



What Next for the Oil and Gas Industry?

John Mitchell
with Valérie Marcel and Beth Mitchell

October 2012



CHATHAM HOUSE

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List of Acronyms and Abbreviations

ACEA	Association des Constructeurs Européens d'Automobiles (European Automobile Manufacturers Association)
ADIA	Abu Dhabi Investment Authority
ADRs	American Depositary Receipt
AEO	Authorized Economic Operator
AIFR	Auto Industry Financial Relief
ARA	African Refiners Association
ASTM	American Society for Testing and Materials
ATTP	Alternative Transportation Technologies and Policies
BCF	Billion cubic feet
BCM	Billion cubic metres
BEVs	Battery Electric Vehicles
BG	BG Group
BNEF	Bloomberg New Energy Finance
BP	British Petroleum
Btu	British Thermal Units
CAFÉ	Corporate Average Fuel Economy
CCICED	China Council for International Cooperation on Environment and Development
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CENPES	Centro de Pesquisas Leopoldo Américo Miguez de Mello (Research Centre)
CEPSA	Compañía Española de Petróleos, S.A.
CITAC	Consuming Industries Trade Action Coalition
CNG	Compressed Natural Gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
COD	Chemical Oxide Demand
CONCAWE	European Oil Company Organisation for Environment, Health and Safety
CSR	Corporate Social Responsibility
DOE	Department of Energy (US)
E&P	Exploration and Production
ECAs	Emission Control Areas
ECJ	European Court of Justice
ECLAC	Economic Commission for Latin America and the Caribbean
ECPR	European Consortium for Political Research
EDHEC	Ecole des Hautes Etudes Commerciales du Nord
EEA	European Economic Area
EIA	Energy Information Administration
ENI	Ente Nazionale Idrocarburi
ENTSOG	European Network of Transmission System Operators for Gas
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency (US)

EPC	Energy Performance Certificates
ERM	Environmental Resources Management
ESPO	Eastern Siberia–Pacific Ocean oil pipeline
ETS	Emissions Trading System
EVs	Electric Vehicles
FYP	Five-Year Programme
GAIL	Gas Authority of India Limited
GCC	Gulf Cooperation Council
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GJs	Gigajoules
HEVs	Hybrid Electric Vehicle
IATA	International Air Transport Association
ICAP	International Carbon Action Partnership
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IEF	International Energy Forum
IEO	International Energy Outlook (US)
IISS	International Institute for Strategic Studies
IMO	International Maritime Organization
INOCs	International National Oil Companies
IOCs	International Oil Companies
IP	Intellectual Property
IPCC	Intergovernmental Panel on Climate Change
IPIC	International Petroleum Investment Co
KIA	Kuwait Investment Authority
KAUST	King Abdullah University of Science and Technology
KPC	Kuwait Petroleum Corporation/Company
KSA	Kingdom of Saudi Arabia
LNG	Liquefied Natural Gas
LULUCF	Land-Use, Land-Use Change and Forestry
MBD	Million Barrels per Day
MCF	Million cubic feet
MPG	Miles per gallon
MPG(US)	Miles per US gallon (= 0.83 UK gallons = 3.79 litres)
MENA	Middle East and North Africa
METI	Ministry of Economy, Trade and Industry (Japan)
MPG	Miles Per Gallon
NAMA	National Appropriate Mitigation Action
NERC	National Electricity Reliability Council
NGLs	Natural Gas Liquids
NHTSA	National Highway Traffic Safety Administration
NOCs	National Oil Companies
NPC	National Petroleum Council
OE	Oil Equivalent
OECD	Organization for Economic Cooperation and Development
OIES	Oxford Institute for Energy Studies
ONGC	Oil and Natural Gas Corporation
OPEC	Organization of the Petroleum Exporting Countries
PDVSA	Petróleos de Venezuela, S.A.

PEVs	Plug-in Electric Vehicles
PHEVs	Plug-in Hybrid Electrical Vehicle
PIW	Petroleum Intelligence Weekly
PSAs	Production-Sharing Agreements
PSCs	Production-Sharing Contracts
QIA	Qatar Investment Authority
QP	Qatar Petroleum
REDD	Reducing Emissions from Deforestation and Forest Degradation
RPS	Renewable Portfolio Standards
SATORP	Saudi Aramco Total Refining and Petrochemical Company
SEC	Securities and Exchange Commission
SPE	Society of Petroleum Engineers
SWFs	Sovereign Wealth Funds
TCF	Trillion cubic feet
TENS	Trans European Networks for Energy
UAE	United Arab Emirates
UNCLOS	United Nations Convention on the Law of the Sea
UNFCCC	United Nations Framework Convention on Climate Change
WBCSD	World Business Council for Sustainable Development
WCI	Western Climate Initiative
WEC	World Energy Council
WEO	World Energy Outlook (IEA)
WOO	World Oil Outlook (OPEC)
WWF	World Wildlife Fund
YPF	Yacimientos Petrolíferos Fiscales (Treasury Petroleum Fields)
YTF	Yet To Find

Executive Summary

The future for the oil and gas industry has changed. For over 100 years the story was one of growth in production to supply a largely Western-driven market, and of competition between private companies for access to reserves. Since 2005, oil prices have moved to a permanently high level. Other industries are capturing some of the demand for transport by producing more efficient engines, vehicles, ships and aircraft, and by supplying alternative fuels. New technologies are providing diverse but uncertain opportunities for producing 'unconventional' oil and gas in many parts of the world. There are also still opportunities for private-sector companies in the traditional oil-exporting countries where the industry is under state monopoly, but generally these will involve cooperation with the state-controlled oil or gas company. Finally, there is a question of who will carry responsibility for the physical security of Middle East oil exports now that these mostly go to Asian markets rather than the US or Europe.

The industry's response to these challenges has implications for the global economy and environment. Oil and gas supply 57% of the commercial energy the world consumes, and their combustion accounted for roughly the same proportion of global CO₂ emissions. Oil and gas exports are more than 15% of the value of global exports and provide more than 25% of GDP in Russia, Central Asia and members of the Organization of the Petroleum Exporting Countries (OPEC). Just over 10% of the value of the world's stock markets is invested in the oil and gas sector. What happens next in the industry will affect the consumers who depend on its products or try to avoid the environmental and social effects of using them, as well as the governments and shareholders who seek tax revenues and dividends from their activities.

The industry cannot develop its strategies independently of governments. The report shows increasing and changing intervention by governments, driven by climate change policies and economic and physical security. Government policies are generated by political processes that cannot necessarily be expected to produce coherent or rational results.

The report does not offer new quantitative predictions. The future cannot be predicted with any confidence, especially while the present (2012) economic difficulties persist. The report's key findings are:

1. The oil industry can no longer rely on its monopoly of the transport market.

Use of oil in transport – half the world oil market and most of its expected growth – is being reduced by competition from other industries. The vehicle industry is replacing oil with more efficient vehicles, and biofuels are replacing oil products as liquid fuels. This is driven both by the increase in oil prices since 2005, and by government policies limiting carbon emissions. Since 2011 all major importing countries have adopted strong policies on carbon emissions and vehicle efficiency. These secure markets for efficient automobiles, rather than for oil. As current policies are unlikely to achieve their aims, it is probable that stronger policies will be introduced. Businesses outside the oil sector are anticipating more severe policies against carbon fuels and are innovating accordingly. The result will be to flatten and reverse growth in the use of petroleum in transport in developed countries, and slow its growth in developing countries.

The major private-sector oil companies have a legacy of refineries and distribution networks in the 'no-growth' markets. Companies will not invest in modernizing these for a short and uncertain future. Refineries will close, brands will disappear, and more products will be imported. Governments will be less able to rely on major international companies to secure supplies.

2. The role of OPEC will change.

The international oil market will continue to be dominated by economics, but the role of OPEC will change. Future weaknesses in short-term demand will be balanced not only by OPEC's regulation of its members' production when prices are weak, but by the response of producers of non-conventional oil, whose high variable costs will drive them to slow drilling and delay new projects. Competition in the medium term will be between investments (made now) in new sources of oil and substitute fuels, and investments that reduce the use of oil by greater efficiency. Competition from outside the oil industry is a real and present threat to demand for oil. Long-term trends cannot be predicted on the basis of business-as-usual extrapolation. Investors look to the industry to show how it will respond.

3. There will be more gas, but uncertainty over where and when.

New perceptions about the potential supply of conventional and 'unconventional' gas (such as shale gas) at relatively low cost are creating the possibility of unexpected expansion of gas markets in most parts of the world. For this to happen each major region needs prices which are low enough to increase demand but high enough to increase supply. Prices at present differ widely between markets. Relying on imports to build new gas demand will seem risky to some countries. In the power sector (which now consumes about 40% of world gas production) the market for gas depends on government policies for coal, nuclear and renewables rather than on factors intrinsic to the gas industry. As many oil and gas companies switch their emphasis from the oil to the gas business, the policies and dynamics influencing the utilities sector – and potentially transport – will be of growing strategic concern. Because a 'golden age for gas' may not prevail soon or everywhere, investors will be concerned about the cost-competitiveness of new projects.

4. Technology and collaboration are the keys to upstream reserves growth.

'Peak oil' is proving a misleading idea. The foreseeable problem is not finite resources but the rate at which these very large resources can be converted into reserves for potential production. Reserves of oil and gas have each more than doubled since 1980 – faster than the increase in production. Technologies are developing which are creating new reserves of 'unconventional' oil, as they already have for gas. These technologies have more places to go, many of them outside the existing oil-exporting countries. These new areas are opening a field of growth for private-sector companies which was not foreseen a few years ago. The companies also still have opportunities for collaboration with state companies, in half of the world's oil reserves, provided they meet each country's terms and conditions and bring technology to complement the state company's own resources. In some countries whose economies depend on oil exports, expansion of production is problematic, because their governments may choose to keep oil in the ground for future production, while gaining time to diversify their economies. Technology is the master key to both sets of opportunities.

With demand vulnerable to other industries, and supply growing from 'unconventional' sources and new areas, there is no long-term escalator for oil prices. There is no clear trend; all depends on investment by competitors for the transport market and on the creation of new reserves.

5. Financing future investment is not a question of quantity but of quality: matching opportunities and risks with sources of funds.

Finance for the private sector in oil and gas depends on investors' beliefs about growth, risk and the prospects for positive change. Inertia is not an option if the industry is to maintain and improve the terms on which it gets finance. Downstream, prospects differ for developed and the developing markets, and upstream for technologies and access to resources in either state-controlled or open-access areas. The private-sector companies need to demonstrate to investors their strategies for managing the declining value of their downstream assets in 'no-growth' markets and accessing the diversity of opportunities upstream. This may lead to radical restructuring of companies and the industry.

Finance for the state companies depends on their place in the national economy, their access to government, loan or bond finance and governments' willingness to involve the private sector.

For investors who look for growth in value or volume, many private-sector oil companies seem configured for the last era and not the next; their public strategies look recycled, not renewed. Few companies seem to question the arguments for vertical integration and there is a legacy of implied obligations to 'meet demand' rather than to engage with the changing forces shaping that demand. Choices are emerging within the industry in which some companies will become energy conglomerates with interests throughout the value chain, while some become focused upstream or downstream companies.

6. *The oil security problem has moved to Asia.*

The geopolitics of oil are changing fundamentally as interregional oil trade divides between the eastern and western hemispheres, with Asian markets absorbing more oil than the Middle East can supply. This changes the security of supply problem. For Western countries, the risk is price, not supply, since disruptions to Asian supplies will affect the world oil price.

Political and physical security measures have not yet caught up with these new realities. Although they are building their own oil stocks, China and other key Asian countries are not part of the OECD/IEA emergency response system.

There is also a political question: how far will the US go to defend sea lanes that mainly benefit Asian countries which import oil from the Middle East? And will Asian countries eventually seek to provide their own protection, individually or collectively? These questions cannot be separated from the wider issues of US military arrangements in Asia and conflicts there, which may prevent the development of cooperative Asian response mechanisms either for physical protection or in order to share supplies.

Conclusion

The oil and gas industry has always changed, and has caused changes in the societies in which it operates. The schismatic changes of the 1970s opened a new era. The combination of changes that the industry now faces requires epic rather than incremental responses, for the industry to evolve and prosper. Those responsible both inside and outside the industry need to try to understand what is happening now and how it may affect the future, to explain their strategies clearly and to adapt to new situations as they develop. In a world where technology and environmental threats are changing industries and society so rapidly, the slowly turning supertanker is not an image that excuses inertia in oil and gas companies and those who deal with them. All who are in the industry or who are involved with it need to share clear thinking about the future.

1 Introduction: The Future Has Changed for the Industry

This chapter sets out the framework for analysis in this report. It sets the context for examining the big changes that mean ‘business as usual’ is no longer a credible future for the oil and gas industry, taken as a whole, and that require it to develop and explain new strategies, both within the industry itself and among those who deal with it.

This report is focused on change. It does not discuss long-running issues which are discussed in many forums, such as the merits of climate change mitigation policies, the effect of financial markets on the volatility of all prices, or government policies which tax the consumption of oil (or subsidize it) or promote alternatives on the basis of environmental or economic criteria which are not applied equally to all fuels.

The short history of the oil and gas industry is an epic narrative broken by transformations brought about by changes in technology, political systems (including war) and the enterprise of those in the industry. For over 100 years the industry story has been of volume growth with discontinuities in the control of markets and resources. With each change some elements disappear as absolutely as the makers of horse-drawn carriages, valve radios and box cameras. Continuities from different eras are reflected in the diversity of the present industry: US companies continue the structure originating from the breakup of Standard Oil in 1911 by the US Department of Justice; European companies have international directions which echo the early exploitation of resources in countries that were either colonial territories or politically dependent on European powers; newer companies which emerged wholly or partly in the private sector after the breakup of the Soviet Union and companies which were created and partly privatized by economic reform in China. Besides these are the National Oil Companies (NOCs), mostly created in the 1970s when the principal oil-exporting countries took back control of their resources from the US and European companies to which they had been conceded in earlier eras. This last change was profound: at the same time rupturing the integrated structure of the major international companies and opening international trade in oil to all comers, where the new state companies were largely sellers and private-sector companies were largely buyers.

For many years the threat of ‘oil running out’ has been suggested as the second big turning point. But this report argues that, on the contrary, it is demand that may be nearing a plateau – at least in developed countries – as the response of other industries to high oil prices and to climate change-related policies ripple through every aspect of economies, so that energy is used more efficiently and other fuels substitute for oil. At the same time the combination of new technology and prices consistently higher than those of recent decades is opening new potential for new oil supplies from shale and other low-permeability formations (‘tight oil’), deepwater and pre-salt oil deposits outside the traditional exporting countries.

The industry is now under pressures that will transform it as profoundly as the changes of the 1970s. The effect of other industries on oil demand, the increasing opportunities for non-conventional oil and gas that offset perceptions of limits to conventional resources, and the shift of growth to Asia will all compel the industry to look for growth in value rather than volume, to distinguish between the expanding markets of developing countries and the declining markets of the private sector in developed countries, and to target technologies to a diversity of resource opportunities outside the state sector and to specialized partnerships within it.

How the industry changes is important for those who invest in it, depend on its products or try to avoid the environmental and social effects of using them, or who look for tax revenues from its activities. Oil and gas supplies 57% of global commercial energy consumption, and their combustion accounts for roughly the same proportion of global CO₂ emissions. Just over 10% of the value of the world’s stock

markets is invested in the oil and gas sector. Oil and gas exports account for more than 15% of total exports, and 25% of GDP, in Russia, Central Asia and members of the Organization of the Petroleum Exporting Countries (OPEC).

This report is not intended to write scenarios or make projections for the distant future. There are so many uncertainties affecting the industry and the world in which it will operate that quantitative projections are of limited use for the decisions which must be made today. Trends and the dynamics of competition are what matter. These are the subject of this report.

Some may find our views contentious. But quantities do matter, and we have used established projections and scenarios from international agencies to illustrate the effect of some of the pressures bearing on the industry, rather than to endorse specific predictions.

Geography also matters. The axis of the oil market is shifting from the trade between the Middle East exporters and US and European importers to one that links Asian developing markets to the Middle East, which no longer has sufficient oil to support these markets' growing needs.

Because the geography of oil production is so different from the geography of consumption, international trade is a continuing feature of the business: 60% of oil consumed is traded between regions.¹ How the international oil market works is critical to the industry and those involved with it.

The balance between state and the private sector has always been a feature of the history of the oil and gas industry. There is no pure private-sector paradigm for oil: even in the United States governments are involved in allocating the resources under the lands they own and in subsidizing the highways on which 14% of the world's oil supply is consumed. In other developed countries consumption of oil in transport is heavily taxed, while in many developing countries it is subsidized either directly or through manipulation of the state monopoly prices.

About 86% of the world's known 'proved' reserves are in social ownership: i.e. owned and controlled by the state or state companies of the countries in which they are located. These countries are unlikely to change their fundamental constitutional right to their natural resources. However, new technology, combined with high oil prices, offers opportunities to the private sector to add reserves in North America and countries where a mixture of state- and private-sector enterprise prevails.

We have not covered every aspect of the industry (for example, oil refining and the gas distribution and retail sector). We have focused on those for which we believe the industry needs to clarify its response to critical changes:

- The effect on the demand for oil of the substitution of oil-avoiding technologies (such as in energy-efficient vehicles) and the use of alternative fuels;
- The resulting split between growth and no-growth downstream markets and its consequences;
- The changing role of OPEC;
- The uncertainties facing gas producers in markets defined by government policies towards alternative fuels for power;
- The perception that limits to the expansion of oil production have weakened;
- The continuing role of national oil companies;
- The financial challenge from investors in the private-sector companies;
- The geopolitical connotations of the shift in oil trade to Asian developing countries

In each chapter we set out the current position, analyse changes in technology, policy and competition, and conclude with the implications for the oil and gas industry.

Chapter 2 looks at the challenges to the oil industry downstream in the transport market. These are driven by economics and the responses of the automotive and other fuel industries to government policies intended to reduce the threat of climate change and dependence on oil imports. These policies seem (in 2012) unlikely to achieve their objectives but are likely to grow stronger when the economic situation

¹ This figure excludes trade within Europe, Southeast Asia, the Middle East and the former Soviet Union.

is less demanding of political attention. Meanwhile industries whose products enable the consumption of carbon fuels to be avoided are thrusting forward new products and technologies as substitutes for oil consumption. In developed countries, demand for oil for transport is likely to decline, while it will increase more slowly than previously predicted in developing countries. Challenges for the industry differ between growth areas in developing countries (mainly dominated by local and state companies), and no-growth areas in developed countries where the main downstream investments of the private-sector companies will decline in value.

Chapter 3 discusses the international oil market and the role of OPEC. Weak demand combined with continuing supply means that longer-term price trends cannot be extrapolated and are unlikely to provide a staircase to the skies for oil prices. For countries whose economies depend on oil export revenues the challenge is to diversify their economies while their own consumption increases at the expense of exports: their national companies cannot deliver growth for ever.

Chapter 4 looks critically at the wide range of expectations about the role of gas in the power sector and of the opportunities for the industry to fulfil that role. The main constraint is that most gas is likely to continue to be produced in countries where it is consumed. International trade is growing but limited by the high cost of transport (though this is falling) relative to the value of the product in the final market. In the major regions the scope for expanding the use of gas in the power industry depends on the availability of local resources together with government policies which promote the use of renewable sources of power and protect or reduce the role of coal and nuclear energy. In each of the major regional markets (North America, Europe and Asia) the problem is to find a price for gas which will both expand its use and increase its supply from sources within the region. Opportunities for new markets for gas, e.g. in transport and chemicals, depend on an expectation of prices that are competitive, and not necessarily linked to oil. The development of shale gas in the US, and particularly in China, may support such opportunities. This means that, although the door appears open for significant expansion of the gas industry in all regions, the size and timing of the opportunities are very uncertain.

Chapter 5 pulls back the curtain on the question of reserves and resources. Public commentaries tend to focus on estimates of reserves. These are indicators of the medium-term potential for growth in companies and countries, but do not reflect the scope for increasing reserves from the much more abundant resources of oil and gas that are now being accessed by new technology. Many of these latter resources lie outside the traditional oil- and gas-exporting countries and represent opportunities for growth in supply to meet demand in the US, and Europe and the Atlantic region in particular.

Chapter 5 also discusses the ownership of the current reserves and the opportunities they present to the private-sector companies in partnership with state companies. For state companies in exporting countries with growing consumption there is the prospect that exports will decline as local consumption rises, unless new reserves are found, or governments relax current policies which conserve oil for future generations. Such conservation is a response to the difficulties of diversifying the oil exporters' economies. The future of many state oil companies is thus closely connected with development of the broader economy of their countries.

Chapter 6 discusses the scope for finding partnerships between private-sector companies and the national oil companies. The latter have needs defined both by the geology of their territories and by their domestic economic roles. They differ in their capacities and competences. The opportunities for partnership with the private sector in one form or another arise where good matches exist between the national companies' needs and what private-sector foreign companies offer. The latter cannot be generalized in terms of finance or technology. Like the national oil companies, the private-sector companies differ greatly from each other. These differences may increase as private-sector companies focus on particular technical, geographic or commercial strengths.

The focus in Chapter 7 is on investors' interests in the private-sector industry. Investors in private-sector companies look for growth and positive change. The challenge for the companies is to demonstrate these in the oil and gas sector. Volume growth is focused in a few regions and many changes are required in companies' portfolios of legacy investments. However, there are large opportunities for investment in some form in partnership with state oil companies, and also for investment in new areas where technology

enables resources to be converted into reserves for future growth. The trends are challenging in terms of the increasing size and technical complexity of projects and the increasing cost of incremental production, so that command of technology is more than ever the key that investors will look for in a company's strategy.

Financial investors are also becoming more diverse and there may be possibilities for them to access projects in infrastructure and biofuels, not necessarily available through the major companies which dominate the private-sector international oil and gas sector. There is a question about whether some of the latter will remain broadly fuel conglomerates or will separate upstream, downstream, gas and oil operations.

Geopolitical and energy security are affected by the changes in the industry discussed in Chapter 8. The shift in the balance of oil trade to Asia means that risks associated with dependence on Middle East oil are concentrated on the Asian markets: the western hemisphere is likely to be more or less self-sufficient in oil for the next few decades. But the developing countries of Asia do not share the mechanisms of the Organization for Economic Cooperation and Development (OECD) for handling supply disruptions, and depend on continuing US military protection of sea routes from the Middle East.

For gas the geopolitical and security spotlight is on particular issues: Russian gas for Europe and its exposure to transit states, and the scope for increasing diversification of Asian supplies from new discoveries around the Indian Ocean and Australasia. So long as international trade in oil and gas continues, competitive prices are likely to be led by the open markets of the Atlantic region. Competition for opportunities to invest in new projects is a different matter and the chapter analyses conditions under which this may or may not merit government intervention.

The report concludes that the constituents of the industry need a new narrative to show outsiders – government, investors and civil society – how they are responding to industrial and policy developments which will affect oil demand, the changing perceptions of future oil availability, and the shift of global oil and gas business to the needs of Asia.

The new narrative is likely to include:

- Focusing the downstream business in developed countries within markets fragmented by competition from industries that replace oil with other products and technology;
- Breaking the corporate integration between downstream and upstream (the traditional vertical industry structure);
- Using upstream technology to match the interests of national companies as well as opportunities to develop new resources into reserves elsewhere;
- Developing clearer and more varied connections between business models and investors;
- Finding clearer parts to play in the evolving geopolitical scenarios between Asia and the Middle East and between Europe and Russia.

2 Downstream Challenges for Oil Business Investments and Initiative

Key points for investment and policy in downstream oil

- The role of oil in transport is being reduced by competition from the vehicle and complementary fuel industries, which are supported by the 2012 level of oil prices and policies to reduce carbon emissions.
- The effect on the oil industry is dramatically different in the no-growth markets of the OECD from that in the growth markets of developing countries, particularly in Asia; the economics of investment in refining in no-growth markets are very negative.
- The oil industry will have difficulty in diversifying into opportunities which are unrelated to its sources, technology or customer interface. Biofuels are attracting investment in process technology by large oil companies, because the result is liquid fuel, but it is uncertain which technology will prove the most competitive, how quickly the industries supplying the feedstock will develop, and what changes will take place in government policies which currently support biofuels.
- State companies dominate the growth markets in Asia, while private-sector companies carry the legacy of investments in the no-growth markets in the OECD.

This chapter considers implications for the downstream oil industry from competition from other industries for the transport market and from policies designed to reduce carbon emissions.

The transport market

The international and national trends to strengthen climate mitigation policies, however complex, fragmented and inadequate to the task, have over the past three years brought business sentiment to a tipping point. It is no longer sufficient to question climate science, scoff at the excesses of the climate change publicists, lobby against disclosure of emissions, or be convincingly sceptical about the progress of international negotiations. The question is how businesses respond to these trends, risky though these responses might be in terms of timing and profitability.

It is not difficult to see growing strength in the response of an increasing number of businesses. The World Business Council for Sustainable Development (WBCSD) places climate change mitigation in a much broader agenda of sustainable development, and its workforces and task groups of major international businesses create the compost for 'bottom-up' growth in new business opportunities.² There are a variety of initiatives by which businesses commit to pay attention to sustainable development, sometimes assessed specifically through carbon emissions. The Carbon Disclosure Project commits businesses to ask their suppliers for voluntary carbon emission disclosure – as is likely to be required in the European Union under the Revised Fuel Quality Directive, which is currently under consideration and review. The intention is to track life-cycle carbon emissions either through actual emission data or through 'default' data typical of each stage of the process.

² WBCSD (2010), *Vision 2050*, World Business Council for Sustainable Development, Delhi.

The pre-emptive business responses are not marginal. Global investment in clean energy rose by 30% to \$237 billion in 2010, of which \$200 billion was in solar and wind in G20 countries, according to Pew/BNEF.³ Nationally, China led the growth, rising 30% to \$51.1 billion, a quarter of the total. By sector, wind power saw the strongest growth, up 31% to \$96 billion (led by China and Europe).⁴

For comparison, capital investment by the 50 leading oil and gas companies is about \$500 billion per year.

The policy push

Major oil-consuming countries are now nominally committed to reducing carbon emissions, though not enough to stabilize global emissions. Many are also concerned about energy security. The combination of international, national and business drives will reduce greenhouse gas emissions and fossil fuel use regardless of the detail of any follow-up to the Kyoto agreement. How far and how fast is difficult to quantify because of the many uncertainties about future technologies, government policies and cost.

Current (2012) climate change policies of governments are summarized in Appendix 1. They will almost certainly prove inadequate, and become stricter in future. Hopefully, some of the contradictions and fallacies of the details of present policies will be removed as better understanding is gained of their environmental effects and economic costs. Nevertheless, it is difficult for businesses to avoid a general trend to invest in markets for capital goods, materials and systems that will reduce the use of carbon in supplying and consuming energy. It is to this that the oil industry, like others, will need to adapt.

Reducing the use of oil in transport

The transport sector is the largest market for liquid fuels. Over 50% of world oil production in 2009 went to transport, Almost 95% of the energy used in transport worldwide was supplied by petroleum in 2009. By 2030 oil's dependence on the transport market may rise to around 60%, depending on the scenarios for climate change policies.⁵ There is no existential threat to the availability of oil for transport because oil can be diverted from other, less valuable markets, where the scope for substituting other fuels is very large. However, policies designed to reduce the emission of greenhouse gases inevitably also reduce the use of oil in transport, which generated 23% of all estimated CO₂ emissions from fuel combustion in 2009.⁶ It is this interdependence that is currently creating a problem for the oil industry.

Petroleum dominates the transport market as a result of a century during which it was relatively cheap, available, and easy to handle and store because of its high energy density and relatively 'clean' properties. Today's vehicle, ship and aircraft industries have grown up as siblings of petroleum. Now they are turning their technology and business models towards avoiding its use. The change in oil prices supports this tendency. Since 2005 the price of internationally traded crude oil has on average more than doubled, in real terms, compared with the previous 20 years (\$31) and is now (2012) three times higher.⁷ Retail prices have increased more, as a result of increases in taxation on consumers (60% since 2007 in the G7 countries).⁸ Within the transport sector oil will face substitution by vehicles (for greater efficiency).

Policies and lifestyle changes are shifting transport off roads, replacing oil by other liquid fuels and by electric vehicles. These changes will slowly affect the flow of money in the transport sector: oil companies will get less, and the vehicle companies more, of what consumers spend on transport. Governments will get less from taxes on gasoline and diesel.

3 BNEF (Bloomberg New Energy Finance), *Global Trends in New Energy Investment*, 2012.

4 For detailed analysis, see Ali Aissaoui: 'Global Trends in Renewable Energy Investment: A Review of the Frankfurt School-UNEP's Report and Discussion of the MENA Case', *MEES*, 23 July 2012. Original Report: Frankfurt School-UNEP Centre, 'Global Trends in Renewable Energy Investment 2012' (fs-unep-centre.org). All data are from BNEF.

5 IEA (2011), *World Energy Outlook*, International Energy Agency, Paris.

6 IEA (2011), *CO₂ Emissions from Fuel Combustion: 2011 Highlights*, International Energy Agency, Paris.

7 2001 \$. *BP Statistical Review 2012*.

8 OPEC Statistical Bulletin 2012 Table 5.7, adjusted for inflation.

In 2011, following the Copenhagen Accord, many countries, including the US and China, adopted policies to reduce greenhouse gas emissions from the transport sector, mainly by requiring new vehicles to meet minimum mileage per gallon or maximum litres per kilometre. These measures are described below in the regional sections of this report for the United States, China, Europe and Japan. As shown in Appendix 2, these and other measures adopted since the Copenhagen Accord will not be enough to limit the probable rise in global average temperatures to 2°C. Stronger policies will be necessary if these objectives are to be achieved. They can be expected when climate change returns to the political agendas from which it has been displaced by the economic situation. They will work through a variety of channels: international agreements, parallel actions by governments, and initiatives by businesses hoping to substitute their technologies for the petroleum dependence of the past.

These changes will be felt most strongly in OECD markets, where they will reduce the demand for oil below its previous trend. In growing markets in developing countries, growth will be slowed. The implications of this contrast are discussed in the first part of this chapter. Appendix 2 provides details of the outlook for oil in transport in the US, EU, Japan and China.

Changes in policies and preferences for transport

Shifting mobility off the roads

Governments in many developed countries, including local governments, seek to reduce highway driving by:

- Favouring public transport with investment;
- Imposing congestion or other charges on the use of highways;
- Not investing in highway expansion, partly because of a departure from the traditional ‘build to meet demand policies’, partly because of budgetary problems;
- Promoting intelligent transport systems, using electronic monitoring and messaging to make the flow of traffic more efficient by communications between the road and the vehicle.⁹

In the US, the use of bicycles has doubled since 2000 and of the buses by 50%, while automobile use has fallen. There have been similar trends in the EU, beginning before the economic slowdown.

The scope for local changes is quite different in the US and in China. In the former the highway system is mature, with car ownership at very high levels. In China, by contrast, car ownership is rising rapidly from low levels; urbanization has some way to go before reaching US levels, and there is an aggressive road-building programme to promote more decentralized development.

In the US, the constraint on further use of the highway system may turn out to be financial. Despite increases in gasoline tax, the revenues earmarked for the Highway Trust Fund have been insufficient to pay for highway investment, which has been subsidized via the federal budget through recurring deficits. An increase in private financing through public–private partnerships seems inevitable, with the result that more roads will be toll roads and the costs of travelling on them will increase.

In China, with many cities yet to be built or expanded, there is more opportunity for providing alternative public transport opportunities to reduce the growth of congestion and urban pollution. This will drive a wedge between increasing car ownership and mileage driven – and therefore fuel consumption.

Changes in choice

There are also changes in the demand for mobility.

- Americans are driving less. In the US vehicle-miles travelled per capita peaked in 2004. On average, 16–34-year-olds drove 23% fewer miles in 2009 than in 2001; fewer of them held driving licences, and they travelled more miles by public transport, cycling and walking.

⁹ For the UK, Department of Transport: Report on Intelligent Transport Systems as required by EU Directive 2010/40/EU.

- The fall in the demand for private vehicles in younger age groups predated the economic decline since 2008, and can be sustained when the economy recovers because mobile phone apps make it easier to identify and use public transport options, with social networking on the internet also substituting for car trips.¹⁰
- The increasing proportion of the population in the higher age groups in the US and Europe, and eventually in China, will also lead to a reduction in individual vehicle use, as driving falls rapidly with advancing age.

How much each factor will contribute is difficult to foresee. There are complex feedbacks. It seems certain, however, that extrapolation of past trends would be wrong for the US itself and for applying historical US trends to new transport use in China.

Shifting the money

Reducing the use of oil may also reduce its price, but not the cost to consumers of using it. Policies – such as carbon taxes or emissions controls leading to carbon prices – will drive a wedge between the prices consumers pay for the cost of motoring (the combination of fuel and buying more efficient vehicles), and the prices producers get for fuel. Some of the difference will be taken by governments in tax, but most is likely to go to the industries whose products and technology enable consumers to avoid oil use. There will thus be a transfer of value from the fuel industry to the vehicle industry.

There is also a paradox for governments which derive large revenues from fuel taxes. If consumption of fuel actually falls, revenues from fuel taxes will also fall. Either the rate of fuel taxation will have to increase, or revenue will have to be found from other sources. These may include taxes on road use or revenue outside the transport sector. So far governments that promote the reduction of oil-dependent transport do not seem to have clarified how they will tackle the resulting revenue problems.

Competition

Efficient vehicles

The automotive industry offers vehicles that achieve the same mileage, performance and size, with less fuel, at costs that can be recouped reasonably quickly at current oil prices. The shift in value from fuel to vehicles creates more jobs and reduces imports in countries that make fuel-efficient vehicles. Government efficiency standards direct expenditure towards vehicles that reduce fuel consumption rather than increasing performance or weight. In 2011 these standards were tightened aggressively in the US, China Japan and the EU (see Appendices 1 and 2). The rough estimates in this report suggest that up to 9 million barrels per day (mbd) of oil demand for transport could be avoided by 2020¹¹ as the vehicle industry applies its continual technical improvements to reduce the gasoline and diesel consumption of the vehicles it offers. Appendix 2 shows the expectations for vehicle efficiency in the principal markets for transport.

Hybrid electric vehicles

Vehicle manufacturers, supported by the power industry, are investing in research and development to develop the most effective hybrid electric vehicle. Many technically different models are on the market in the US, China and Europe. Hybrid vehicles receive a variety of government incentives in most OECD markets: exemption from certain types of tax and credits towards fleet fuel averages required by CAFÉ standards. Most major vehicle manufacturers offer hybrid cars to gain these benefits. In the US, the world's biggest market for hybrids, these policies are predicted to raise the share of simple hybrid vehicles

10 Frontier Group and US PIRG Education Fund (2012), *Transportation and the New Generation: Why Young People are Driving Less and What it Means for Transportation Policy*, Frontier Group.

11 This figure is a rough sum of differences between current policy scenarios and strong policy scenarios such as the IEA '450 ppm' scenario (see note 20). It is not a projection, since the necessary policies are not in place.

(HEVs), where the electricity is generated on board from the petroleum engine, from 1% to 6% of the vehicle stock by 2030, while the share of plug-in hybrids (PHEVs) and all-electric vehicles is predicted to increase from near-zero to 2%.¹²

In the medium term, the main impact on the demand for petroleum is likely to be the increased use of HEVs. They will have an unequivocal effect in reducing greenhouse gas emissions. They do not depend on the use of electricity generated outside the car or truck. The size and efficiency of the battery affect the range achievable without gasoline use. The market is where the majority of journeys are likely to be within the range of the battery and longer journeys can be made with the gasoline-powered train. Hybrid vehicles continue to require combustion engines, petroleum products and existing distribution and retail networks from the automotive and petroleum industries.

The agriculture industry: are biofuels the new agribusiness?

In the short term, the agriculture industry and lobbies offer substitution for oil by ethanol, mainly through gasohol (up to 10% ethanol) or E85 (up to 85% ethanol) and biodiesel. The IEA's *World Energy Outlook 2011* projects that world use of biofuels would increase by 1.7 mbd by 2030 if current policies to subsidize consumption in the US and the EU were continued.¹³

Despite uncertainties about policy (see below), major US and EU companies in the agriculture, oil, process control and chemical industries are investing for the longer term, in research and projects for the development of processes to produce 'second-generation' (cellulosic or algae-based) biofuels which would avoid encroaching on food supply. The competition at this stage is mainly technological: to find the most efficient means of converting large quantities of low-energy-intensity material into a liquid fuel at a marketable price. Large-scale use of biofuels would require not only cost-effective technology but the development of a new industry to harvest and process the source material in areas that are not currently productive. In China, major state agricultural enterprises, and CNOOC, are investing in the expectation of exploiting Chinese straw production. For the oil industry, biofuels have the advantage of being a liquid fuel that can be distributed and processed through the industry's existing infrastructure, with only minor modifications, and some companies are investing accordingly.

Biofuels for transport are limited by contradictory constraints, which affect some more than others. If they are produced on existing agricultural land, they may divert production from food supply, though EU regulations are intended to prevent this; if they are produced on newly cleared land they may not reduce greenhouse gas emissions and may even increase them temporarily because of the emissions generated by the clearance. Costs are often not competitive with gasoline or diesel if the effect of favourable tax treatment is ignored. It is government mandates that drive biofuels into most markets. The exception is the production of ethanol from sugar cane in Brazil. The use of ethanol and ethanol blends is mandatory in this country, where its economics and carbon emissions benefit from the high productivity of the land, its alternative uses, and the use of the waste by-products (bagasse) to generate power; the Brazilian automobile industry has responded by developing flex-fuel engines, and the refining and distribution system dominated by Petrobras, the state company, provides availability.

Government policies to promote biofuels are under challenge and, like policies promoting electric vehicles, will change as the technology and its costs and benefits develop and are better understood.

- US subsidies of \$0.45 per gallon ended in January 2012, but in July 2012 the administration announced new grants for research on 'drop-in' biofuels, mainly for aviation use.
- In the EU, biofuels have been subsidized through excise tax breaks and there has been a mandatory target to use 10% renewables (in effect, biofuels, mainly biodiesel) in fuels for road transport by 2020. The target, provided and supported by farming lobbies, is qualified by criteria on cost-effectiveness and sustainability.

¹² EIA (2012), *Annual Energy Outlook*, Energy Information Administration.

¹³ US Annual Energy Outlook (AEO) 2011 projects 1 mbd increase from renewable liquids in the US alone over this period.

- The EU policy is now (2012) under review. It has been challenged on the grounds of cost, and because it encourage changes in land use¹⁴ in countries exporting biofuels to the EU, with resulting increases in GHG emissions.¹⁵ At the same time the political leverage of green parties in many countries is in decline, usurped by the growth of populist and nationalist movements with quite different priorities.

The gas industry

Where natural gas is cheap there are opportunities for it to replace oil in transport. Shell has recently announced a programme to supply LNG for trucks in the US. In China, despite high gas prices, LNG as a fuel for trucks is being actively pursued. In the past the replacement has been upstream, based on conversion of gas to liquids that are then blended with refined products. With modifications in the design and technology of engines, it is possible to substitute compressed natural gas (CNG) for gasoline in internal combustion engines, and to use LNG in place of diesel in trucks, buses and ships. Vehicles designed for fuelling by gas require dedicated distributed systems. Investment is likely to focus on areas or markets where consumption is concentrated and investments can be linked to local advantages in gas supply.

The power industry

For the longer term, a variety of industrial groups are investing in research to develop plug-in hybrids and battery electric vehicles (BEVs) which could transform the demand for liquid fuels, the shape and constituents of the automotive industry, and the infrastructure of countries such as China, whose transport systems are less dominated by the legacy of fuel infrastructure than in mature economies. Their effect on the environment depends on the fuel used to generate power – unlikely to be oil – and the processes of manufacture and disposal of batteries. Plug-in electric vehicles and all-electric vehicles (EVs) would bring electricity into the transport mix, to replace liquid fuels. They would expand the market for fuels for power generation, including gas where it is cheap. The effect on greenhouse gas emissions would depend critically on the mix of fuels used to generate the electricity in the grid: vehicles powered by coal-generated electricity will cause the emission of more greenhouse gases than conventional vehicles powered by oil products.

The industrial components for electric vehicles – batteries, powertrains, connectors and supply equipment – will be global, but the mix of fuels used in electricity supply will be shaped by local resources and policies, which in turn will depend on the local combination of nuclear, gas, renewables and coal power used to meet the additional demand, and on charging and tariff regimes to use off-peak capacity.

China has a very ambitious EV development programme. The target is for cumulative EV sales to reach 0.5 million by 2015 and 5 million by 2020. The 2015 target will be difficult to meet unless low-end small EVs, which are already running in third-tier cities, are counted.

China is unique in possessing all the elements for an electricity-based transport supply chain: the road system and urban development designed to accommodate a large segment of short-journey travel, charging infrastructure, vehicles and battery manufacture, lithium, coal and nuclear power. All are capable of being coordinated by government (the sector is prioritized in the 12th Five-Year Programme (2011–15). Because the market and manufacturing base are so large, competition will drive down costs and pick winning technologies. All the elements have bases in export industries, so that the shape and timing of the Chinese electric vehicle development will have global reach.

Industrial groups are also researching technologies for hydrogen-fuelled vehicles. Hydrogen produced from hydrocarbon fuels would not necessarily have the desired environmental effect. The effect of producing hydrogen from electricity and water would depend on the power source used in generating electricity.

14 The so-called Land Use, Indirect Land Use Change (LULUC) effect.

15 Friends of the Earth and Actionaid, *The Bad Business of Biofuels*, February 2012; Schrotten, van Essen, Warringa, Boech, Smokers and Fraga, *EU Transport GHG: Routes to 2050*, <http://www.eutransportghg2050.eu/cms/assets/Uploads/Reports/EU-Transport-GHG-2050-II-Task-8-drafftinal14Feb12.pdf>, accessed 6 June 2012.

Aircraft industry

In 1996 the Intergovernmental Panel on Climate Change estimated that the aviation sector consumed 13% of all transportation fuels and produced almost 3% of anthropogenic CO₂. Because of the effect of other gases released by aircraft, the total global warming impact may be two to four times higher than that of CO₂.

In the 1990s aviation was the most rapidly growing sector of the oil market. However, growth rates have slowed in most countries in this century. In the US and Europe aviation fuel consumption fell sharply with the economic slowdown after 2008.

There are no international agreements to restrict emissions from aircraft. The European Union requires, from 2012, all aircraft using EU airports to participate in the EU emissions trading system (ETS); initially international airlines will be monitored, and eventually they will be brought into the allowance system. The EU system has been challenged legally by foreign airlines, but upheld by the European Court of Justice. Some foreign airlines are now threatening retaliation. The International Air Transport Association (IATA) argues that economic measures such as the ETS should have international, non-discriminatory application.

Meanwhile, the aviation industry is working to anticipate policy by achieving carbon-neutral growth from 2020 by:

- Continuing technical improvements in aircraft propulsion, aerodynamics, weight reduction;
- Working with traffic control authorities to achieve more efficient traffic management and operating procedures;
- Seeking better infrastructure at airports.

In the longer term radical designs such as the flying wing (used in the Stealth bomber) may be developed for more general use to improve aerodynamics and thus reduce fuel use and emissions. None of these developments will have much effect soon. Over a quarter of the total aircraft fleet will need to be replaced by 2020, and IATA estimates a reduction of 21% of emissions compared with business as usual.¹⁶ New aircraft models need to be tested and sold into the fleet; it will take time for the most cost-efficient models to emerge from competition. IATA estimates of the impact of technology in terms of emission reductions show wide ranges with indeterminate timing, as Table 1 illustrates.

Table 1: Potential GHG emission reductions due to new aircraft technologies (%)

Retrofits	7–13
Production updates	7–18
New aircraft design before 2020	25–35
New aircraft design after 2020	25–50

Source: IATA, 'A Global Approach to Reducing Aviation Emissions', 2009.

In the medium term the industry is looking for 'drop-ins' – biofuels that may be blended into jet fuel. The international certification body ASTM has produced specification D4054-09 which sets out conditions for adding biofuels to aviation fuels. Various fuels and blends are being tested. As with biofuels for ground transportation, the effect on global warming depends on the origin of the biofuels: few of the first generation biofuels unambiguously reduce CO₂ emissions; the 'second generation' has yet to be developed on a large scale.

¹⁶ IATA, 'A Global Approach to Reducing Aviation Emissions', 2009.

Shipbuilding

In 2009¹⁷ the oil industry supplied almost 3 mbd of residual fuel oil for commercial shipping – 3.5% of world consumption of liquid fuels, accounting for just under 3% of man-made greenhouse gas emissions. These figures are expected to increase if marine transport is not subject to new policies (the EU is consulting on such policies). Shipping emits fewer greenhouse gases than other forms of transport, but does not serve similar markets except on inland waterways, as EU transport policy recognizes.

In contrast to the aviation sector, fuel efficiency and emission reduction for ships are driven by international regulation through the International Maritime Organization (IMO). An IMO study in 2009 estimated that technical and operational measures could reduce the emissions rate to 25–75% below the current level.¹⁸ In 2010–11 the IMO marine environment protection committee developed a set of efficiency measures which will be mandatory for all ships irrespective of flag and ownership. Regulations will enter into force during 2012 and will affect ships of 400 gross tonnes and over. In 2012 the Chinese company SINOPACIFIC launched the first ultra-max bulk carrier to meet these standards, with fuel reductions of 13% without speed reductions.

The regulations do not cap marine emissions. At the Durban Conference of the Parties of the United Nations Framework Convention on Climate Change (UNFCCC) in 2011 the International Chamber of Shipping joined Oxfam and WWF in calling for economic measures – in the form of a carbon charge, rather than a cap, on emissions by ships. The EU, however, is considering ways to incorporate shipping into the ETS, which would impose caps.

A variety of technical measures are available to improve fuel efficiency in ships without any retrofitting or investment. The companies chartering ships are increasingly demanding lower fuel costs, which can be delivered by:

- Sailing at slower speeds – but this has a directly visible economic cost;
- Paying more attention to optimizing ballast, arrival times and journeys;
- Applying antifouling coatings;
- Better use of waste heat;
- Use of shore-based electricity when in harbour.

For new ships there are more options:

- Improved design of hulls, propellers and systems;
- In the longer term, partial replacement of the oil by other fuels such as biomass or even LNG, if the various technical problems are overcome. The US Navy plans to spend \$510 million to promote advanced alternative fuels.¹⁹

The IMO has imposed Emission Control Areas in Europe and the US. Starting in 2015, all cargo entering those ECAs needs to comply with very strict regulations regarding the sulphur content of fuel oil and NO_x emissions. This is a very important challenge for the international shipping industry and an opportunity for the gas industry. LNG is one of the alternatives to fuel oil to meet the ECA requirement.

Implications for the oil industry downstream

Importance of policy

The key story of the opening of the transport market to competitors for oil is the effect of policy on the expectations of the manufacturers of vehicles, aircraft and ships. This combines with the expectation that oil prices have reached a new level that makes more competition economic. There are a variety of

17 Latest year available. Does not include diesel fuel or naval use. Statistics are incomplete: IEA International Energy Statistics.

18 Consortium of Institutions led by MARINTEK, *Second IMO GHG Study*, 2009, IMO, London.

19 'Ray Mabus, US Navy Secretary, defends biofuels investment', *Huffington Post*, 13 March 2012.

mandates for the use of renewable fuels and incentives for the development of HEVs and PHEVs (and batteries for both of them). But the details are uncertain. The incentives are set up on the basis of the knowledge available to the governments at the time, filtered by public perception and interest groups. These will change as the industrial response becomes clear and the cost of incentives becomes large enough to matter at the level of national budgets.

Uncertainty and the sequence of information

The implications of these changes for the oil and gas industries are complex. Volumes matter to the upstream. Volumes also matter to the downstream, but in much more detail. Extrapolations from the past almost certainly do not adequately allow for the development of technology by industry and of policy by government. This especially applies to extrapolation for developing countries such as China where the future will be dominated by vehicles, infrastructure and habits which have yet to be formed, unlike the legacies in the developed countries. Estimates of future demand for petroleum as fuel cannot be made reliably until a better idea emerges of the stringency of future climate change policies, the winning transport technologies, and changes in lifestyles that drive the demand for ‘affordable mobility’. Inertia is powerful, but the forces driving towards reducing the trends in the demand for oil in transport in the longer term are very strong.

The idea that most of the adjustment to lower oil consumption in transport would occur after 2020 suits the automotive industries quite well, as they aim to reduce oil use in transport. It will take time for competition to sort out the dominant technologies and companies and to develop the market. However, the delayed change creates a big difficulty for the oil industry downstream in the US, the EU and Japan, which are the main markets for the international oil companies. They will be expected to maintain the refineries, distribution and retail structures for static or slowly growing markets for the next ten years. The cost of keeping going is not negligible, as changes in the mix of products and new environmental standards will require continual investment to maintain assets whose life will be short.

Geography matters

The downstream oil industry faces a contrast between:

- The transition to long-term structural decline in OECD countries such as the US, where the underlying demand for transport will increase slowly, and oil consumption will be driven down by innovation from the vehicle industry and other transport fuels; and
- The persistence of the old model of growing demand in regions where the transport demand is driven by economic growth and rising per capita incomes, as in China and other Asian developing countries.

The contrast is illustrated by projections by the International Energy Agency (in its *World Energy Outlook 2011* (current policies scenario) and the US Energy Information Agency’s *International Energy Outlook 2011* (reference case), which are broadly similar in concept. Both agencies offer a variety of scenarios for different combinations of policy, supply and demand. We use the IEA ‘450 ppm’ scenario²⁰ as an indication of what stricter climate policies might do to the outlook under ‘current policies’. It is now clear that current policies to achieve 450 ppm are not in place and that this objective will not be achieved. Nor does this scenario necessarily represent how the burden of reducing greenhouse gas emissions will finally be shared between countries.

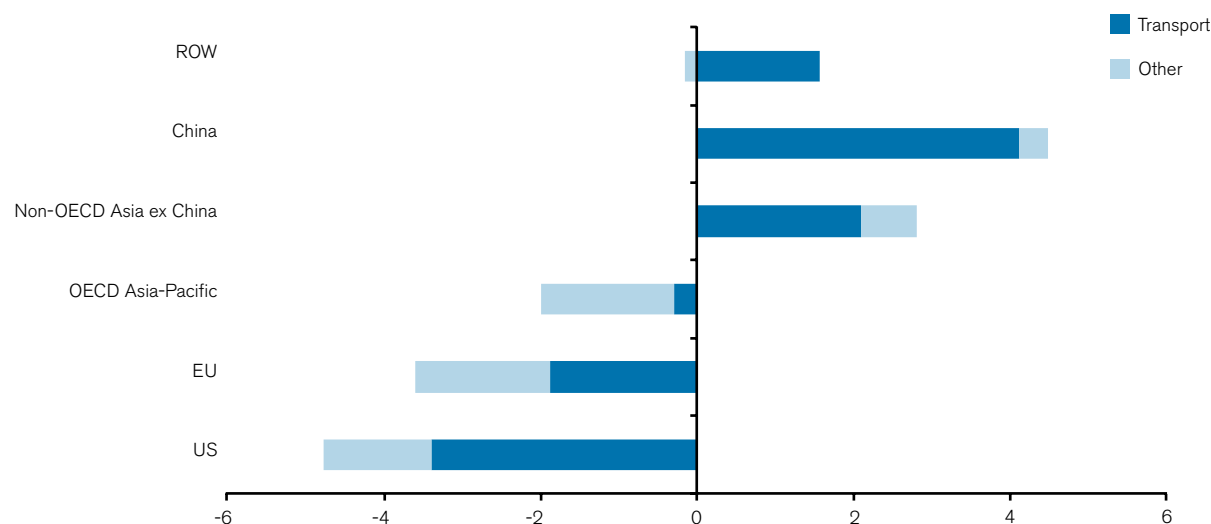
We use these scenarios only to show the contrast between current policies and severe policies which are not yet defined, but which the ‘450 ppm’ scenario represents. (The IEA 2011 scenario for ‘New Policies’, as seen in mid-2011, represents the IEA’s judgment of what might be feasible politically over a 25-year period. This judgment is likely to change, and is not the point of this report, which does not aim to produce new projections.)

²⁰ The 450 ppm (GHG concentrations) scenario, defined by the International Energy Agency, sets out an energy pathway that is consistent with a 50% chance of limiting the increase in average global temperature to 2°C compared with pre-industrial levels.

Figure 1 illustrates how oil use would change between 2009 and 2030 in the ‘450 ppm’²¹ scenarios of the IEA. The more severe policies predicted earlier in this report would be similar for the transport sector, and these numbers give an indication of their effect over a 20-year period – which is unlikely to be the period to 2035 used in the scenarios, since the necessary policies are not likely to be in place soon. Projections by other agencies²² show similar impacts, even when the artificial ‘450 ppm’ target is omitted. As Figure 1 shows, it is the transport sector that dominates the change in oil demand.

Figure 1: Change in oil use, 2009–30 (mbd)

Source: IEA WEO 2011.



These are big changes from the current situation. Table 2 compares them with the current consumption of oil in the transport sector. Over 20 years, policies like those in the ‘450 ppm’ scenario would cut the use of oil in transport in the US and EU by 30%. In China they would halve the growth expected under current policies.

Table 2: Change in oil use for transport, 2009–30 (%)

	Total to 2030 for 450 ppm scenario
US	-31
EU	-31
Non-OECD Asia ex China	66
China	133

Source: IEA WEO 2011.

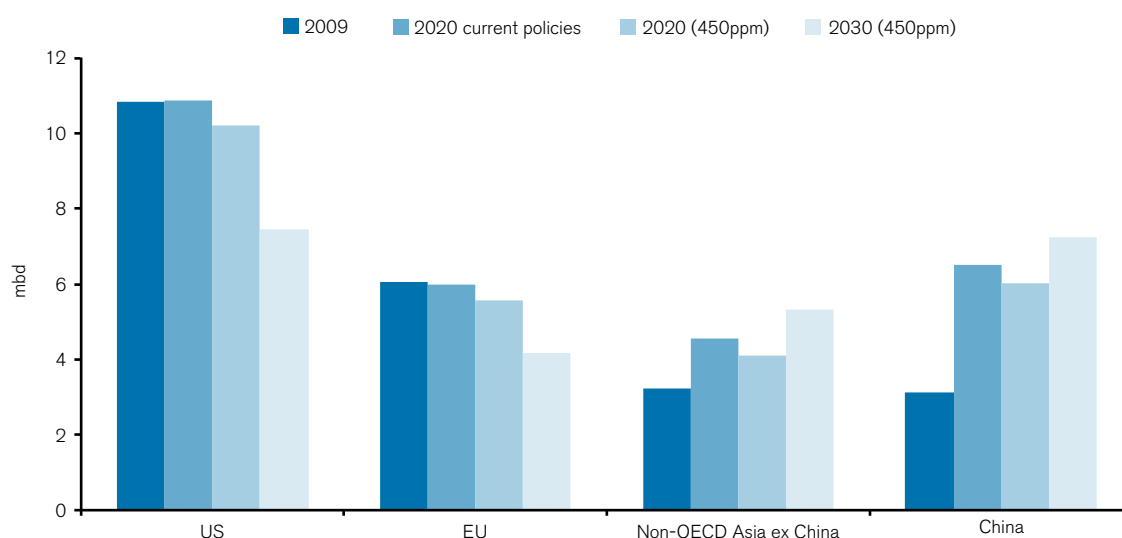
The cliff effect

The timing of more severe climate policies is uncertain but the scenarios show the problem: nothing much happens for about ten years; then, in the developed markets, most change happens in the second decade. Figure 2 shows the changes.

21 Stabilization of greenhouse gases at this level is supposed to give a 50% chance of limiting global warming to 2°C by the end of the century.

22 The US EIA and ExxonMobil, OPEC, *World Oil Outlook 2011: Alternative Transportation Technologies and Policies (ATTP) Scenario*.

Figure 2: Oil for transport



Source: IEA WEO 2011.

This would create an off-the-cliff effect in the US and EU, particularly on the investment necessary to meet demand, either within the shrinking oil system or in the alternatives. In simple terms, under current policies world demand for oil transport would increase by about 8 mbd by 2020 outside the US and EU. With the more severe climate policies typified by the '450 ppm' scenario, the US and Europe would then lose up to 6 mbd in the next decade – a reduction of about 30% from today's levels. In Asia (excluding the OECD) growth in demand would be halved: 6 mbd instead of 12–13 mbd.

No-growth markets: the OECD

In no-growth markets, the approaching decline in petroleum use will erode the value of refining and marketing assets. At the same time retail demand will be fragmented by local policies on transportation systems and the development of locally based competition from alternative fuels and vehicles.

The continuing legacy of downstream assets in Europe is burdened by the need to invest: for the refining industry it is a question not just of managing decline, but of adapting to new demands for fuel quality and automobile performance. The European Fuel Quality Directive, currently going through the legislative process, will apply greenhouse gas reduction targets to life-cycle emissions from transport fuels. Inputs to each refinery will have to be tracked and refineries' exposure to targets will reflect the local availability of biofuels and the local crude supply mix. This will reinforce the fragmentation of markets referred to in the previous chapter. In Europe, refineries also face uncertainty about the balance between diesel and gasoline.²³ In most European countries diesel enjoys a favourable tax treatment, which now may be withdrawn in favour of a carbon-based tax. At the same time gasoline engine efficiencies have been improved by the use of the direct injection system normal for diesel, and there are concerns that other pollutants may need to be removed from diesel emissions for health reasons.

Companies may respond in different ways, according to their legacy of assets and portfolio of opportunities. This will involve further restructuring along lines that have already begun, including:

- Concentrating refining in a core of plants, sectors, networks and technology with continuing advantages: scale, and cost efficiency even in no-growth markets. Companies can secure some segregation of markets for their output by integration with chemical sites, and some advantage in their input by developing the capacity to handle special crude, which would be at a discount

²³ *Petroleum Intelligence Weekly*, 18 June 2012.

in the open market. The key to this strategy is attention to technology.²⁴ Such refineries have the opportunity of capturing some of the value of the final product which the crude exporter cannot reach.

- Closing refineries or selling them to smaller independent companies (if any can be found) which can show a profit on their acquisition cost and will run them for cash until the investment requirement becomes too severe, and to innovative companies using part or all of the facilities to process new materials (biofuels, waste, etc.). In Europe this may not be feasible, so that refineries will close and products will be imported from elsewhere – including export refineries in oil-exporting countries, such as Russia for Europe, Venezuela for the US, the Middle East (or refineries en route) for Japan. The pattern of trade in products will change.
- Closing retail outlets or selling them to independents such as supermarkets capable of carrying the environmental and security of supply risks. This may involve the disappearance of major oil company brands from parts of the market.
- De-integration: the recent demerger of Conoco and Phillips may be the beginning of a trend for some categories of company in some countries. If a strong, margin-oriented, downstream business can emerge despite declining throughput, major companies could gain value by demerging from upstream activities. Provided the demerged downstream company has access to an open market for crude oil products there is little supply risk. Demerging would enable financial markets to recognize the value of the downstream with its appropriate risks, and would give both upstream and downstream managements very clear, but different strategic focus.

The consequence of such restructuring will be that less volume will go through the larger companies and more through the general retail sector. Governments responsible for market regulation and structure will need to give more attention to a wider range of companies, and place less reliance on the former marketing or refining majors.

Growth markets: developing countries, especially in Asia

Mere presence in a growth market is an opportunity, not a guarantee of increasing volume profitably. In China, Southeast Asia and India, rapid growth eases the problem of adjusting to higher standards for product quality and environmental processes. A private-sector company (Reliance) has demonstrated it is possible to succeed in India in terms of both scale and quality investment by investing in new, state-of-the-art capacity.

The key new question is how far the recent shift in international prices will lead local governments to allow product prices to reach levels that allow sufficient funds for the state companies to finance investment, and the private-sector companies, where they have part of the action, to make a profit. Many governments are attempting to increase domestic prices for budgetary reasons (in importing countries such as India), to reduce imports (as in China) or to liberate domestic supplies for export (as in Iran and the UAE).

Major international companies have withdrawn from a number of small markets (e.g. in Africa) and will continue to do so, leaving a challenge for those developing-country governments to achieve efficient operations either through independent domestic companies or through a new set of foreign companies. Where they operate, private-sector companies may achieve profits based on strategic selection of the locations and product streams on which they will concentrate in the business space allowed to them. In many growth markets private-sector companies cohabit with state-controlled companies (sometimes with private shareholders), often in export refineries (as in Indonesia, Saudi Arabia and Venezuela), but sometimes in the domestic market, together with local private-sector companies (as in India).

State companies also have to contribute (along with their other developmental obligations) to the new policies in some countries (UAE) to increase the efficient use of oil and accommodate the use of renewable substitutes, in order to sustain oil exports. This requires an attention to the details of domestic markets that has not necessarily been shown by the upstream-driven state companies in the past.

24 ExxonMobil, Financial and Operating Review, 2011, p. 63.

In Asia the case for continuing vertical integration is different from that in the Atlantic region. Oil-importing countries (mostly through state-controlled companies) will be importing from a small number of also state-controlled companies in the Middle East. Investment in specific refinery technology for specific crude qualities may be better secured by long-term bilateral arrangements than by relying on an open market for crude and very flexible refinery capacity. Open Asian international crude and product markets will continue to exist (there will be enough marginal suppliers and customers, and exports to or imports from the Atlantic region will always provide a marginal alternative. A hybrid structure may develop comprising:

- Long-term crude supply contracts to major Asian refiners, with some price stabilization or profit-sharing trimmings, linked to investment in adapting refineries to particular crudes;
- More investment by exporting-state companies in joint-venture refineries in Asian importing countries, with implied netback pricing;
- Independent refiners protected by local conditions, buying crude as at present.

If a market structure on these lines were to develop in Asia, the opportunities for foreign private-sector companies to share in the market growth would be limited.

3 International Oil Markets

Key points for oil markets and prices

- The continuation of the global oil trade, with its risks and benefits, is inevitable, as is a role for state companies in many economies that are dependent on oil exports. However, the industry is entering a new era when the narrow focus on supply and OPEC needs to be widened.
- Uncertainty about demand will affect investment in new oil capacity generally, not just in OPEC.
- For the industry, competition is now between new oil substitutes such as biofuels, and the take-up of technologies that deliver service while avoiding the use of oil.
- Among oil exporters, OPEC will have a continuing role in supporting prices when demand falls short of capacity, but the producers cannot get any price they want. The success of governments in oil-exporting countries in reducing dependence on oil exports will be what determines the benefits they can achieve for their populations.²⁵

This chapter describes changes the oil industry has to face within an international structure in which the balance between state-controlled companies and private-sector companies is different upstream from downstream and between growth and no-growth markets. Competition in the international oil market will inevitably continue, but the role of OPEC may change.

State and private sector

The state companies' share of known world oil reserves (about 86%) is not reflected in their share of production (55%) because of their more conservative depletion policies and lack of investment, as well as obstacles to private-sector investment by foreign companies. In many economies where there are few alternative sources of revenue, state-sector production is limited to depletion of reserves at lower rates – typically 3–5% – to conserve oil for future production. Private-sector companies are driven to more rapid depletion rates – 10–12% – by economic considerations, including the higher cost of capital and corresponding discount rates.

This situation is a legacy of the period from the nineteenth century to the 1960s when private-sector companies from the US and Europe enjoyed nationwide, or very large, concessions to extract oil from developing oil-exporting countries. International crude trade was carried out mainly within the integrated businesses of the eight major private-sector companies with concessions in the exporting countries and refineries in the importing countries. The open market in crude oil probably constituted only about 10% of international trade.

The shape of the international oil industry changed fundamentally when, from 1971 to 1980, governments in the Middle East, North Africa and South America started to participate in the concession companies. In most cases they ended up with 100% ownership, which was then vested in the state companies. There was a

²⁵ For an illustration of the difficulties, see Ali Aissaoui, 'Saudi Arabia's Economic Diversification: Progress in the Context of the GCC and Challenges', in Giacomo Luciani, ed., *Resource Blessed: The Challenge and Potential of Economic Growth and Diversification in the GCC* (Berlin and London: Gerlach Press, 2012).

transitional period during which long-term contracts continued between the international companies and the state companies in their former concessions. But after the second oil shock of 1978–79 and the resulting price disruptions, these arrangements mostly fell away.

The present structure is unlikely to disappear: private-sector companies will not regain control of the nationalized concessions. Although there has been and will continue to be some overseas investment downstream by state-controlled exporting companies, these companies will not displace the private sector downstream in the OECD markets, or the state-controlled domestic companies in developing markets such as China and India. Trade is inevitable – most of it at arm's length, between state-controlled companies exporting crude and refining companies which, in the OECD, are mostly in the private sector. State-controlled companies, with 55% of world crude production, have only about a third of the world's refinery capacity (mainly in their own countries) and supply less than 40% of product sales, as shown in Table 3.

Table 3: Upstream to downstream, top 100 companies' share of world liquid output, refining capacity and product sales (%)

	Liquids output		Refinery capacity		Product sales	
	2010	2000	2010	2000	2010	2000
Private sector	25	22	32	33	53	55
State companies	55	48	34	26	37	32

Sources: Energy Intelligence Top 100: Corporate Comparison Tool; BP Statistical Review 2011.

The sales figures include crude product bought and resold: both sectors sell more than they refine.

Most exporting-state companies impose restrictions on their sales to prevent the reselling of their exports in the open market. However there are sufficient private-sector and other producers who do not place such restrictions (which are illegal in Europe and the US) to support the open markets with futures and commodity exchanges, which have been established since 1980 in New York, London and Dubai. Most of these unrestricted suppliers are in the Atlantic region, where the decline of North Sea production is being offset by increases in production in the US Gulf of Mexico and the Atlantic basin.

The balance of trade is shifting east: the major integrated private-sector companies have about one-third of their downstream investments and markets in North America and about one-third in Europe. In both they face declining demand. In the Asian growth markets local, mainly state companies hold the dominant market share.

The Asia-Pacific region in 2011 consumed 32% of world oil production, more than twice as much as in 1970. Almost half of world oil imports went to this region. Projections for 2030 point to an increase of around 40% in consumption in the Asia-Pacific region, which will take over 60% of world oil trade.

Competition and OPEC

Competition in the international crude oil market has passed through many phases.

Company control (until 1973)

Each of the foreign companies (usually in a consortium or joint company, such as Aramco, IPC, KPC, Iranian Oil Consortium) decided its production rates and prices, under pressure from the government of the country owning the reserves. The eight major international companies held shares in several national consortia. The international companies attempted to expand the market at prices which would not destroy their profits, in effect operating a cartel-like system.²⁶ The system weakened in the 1960s as other companies

26 Edith Penrose, *The Large International Firm in Developing Countries: The International Petroleum Industry* (London: George Allen and Unwin, 1968).

gained concessions in new areas such as Libya and Nigeria where multiple concessions were granted. New competition eroded prices in the importing countries. Major exporters lowered their posted prices. With their prices essentially fixed by foreign companies, the governments of the exporters depended on growth in volume to increase their revenues, though some improvement came from adjustments to the terms of the concessions (royalties, treatment of tax etc.²⁷). The result was pressure on the foreign consortia to expand production at least in line with expansion by other exporters. The pressure of supply on world markets in turn reduced the price the foreign companies were prepared to pay. The events of 1970s broke this unsustainable circle. The governments of exporting countries temporarily gained an opportunity to raise revenue by increasing prices regardless of the effect on volume, (known as the 'backward sloping supply curve'²⁸).

Transition to OPEC (1969–80)

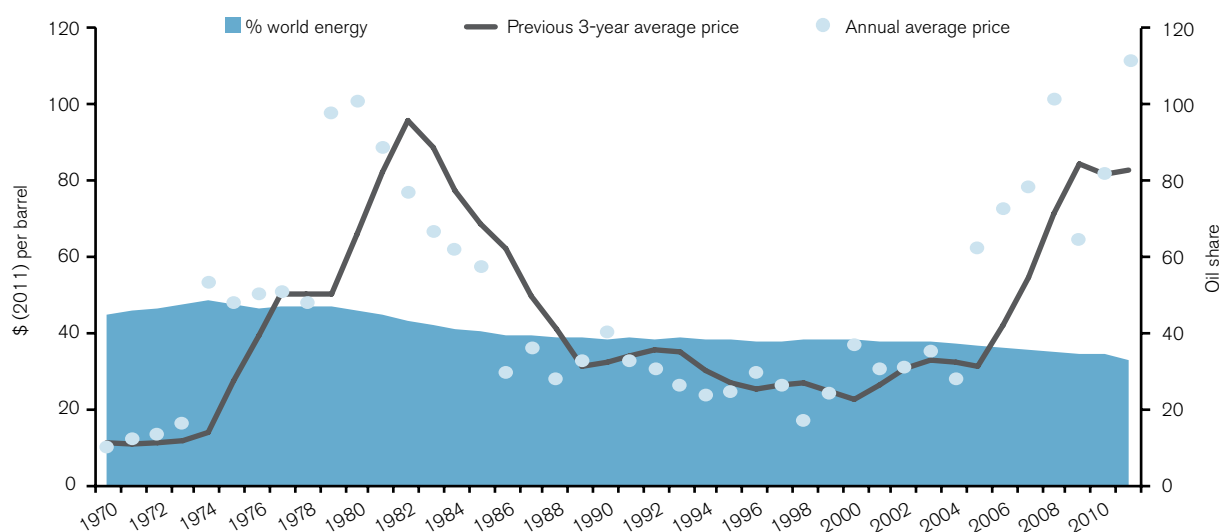
OPEC was founded in 1960 by four Middle Eastern governments and Venezuela as a defensive, and at first mainly ineffective, response to falling prices. By 1970 the supply–demand balance had turned in favour of the producers. The foreign companies negotiated with the producers and reached agreements (the so-called 'Tripoli and Tehran' agreements) for increases in prices and other improvements between 1970 and 1973. In parallel, following a 1968 OPEC declaration, member countries took action (with different phasing in different countries) either to nationalize or to take a majority interest in the concessions enjoyed by foreign companies.

Negotiations on a new price formula broke down in October 1973, coincident with the Arab–Israeli war and the unilateral embargo by Arab oil exporters on exports to countries deemed to be supporting Israel ('the first oil shock'). From that point, prices were set by the exporters alone.

Intra-OPEC competition since 1979

The transitional arrangements collapsed in the disruption to the market caused by the Iranian Revolution of 1978 and the Iraq–Iran war of 1979 (the 'second oil shock'). A period of great instability in prices followed. Spot trading – formerly insignificant – grew rapidly. Oil futures contracts were set up in New York and London: now anybody could buy oil and the exporters had to sell at prices that would clear in the open markets.

Figure 3: Oil prices and share of global energy market



Source: BP Statistical Review.

27 See Francisco Parra, *Oil Politics, A Modern History Of Petroleum*, Chapter 5 (London: I.B.Tauris, 2004, 2010).

28 David G. Victor, David R. Hulst and Mark C. Thurber, eds, *Oil and Governance: State-Owned Enterprises and the World Energy Supply* (Cambridge University Press, 2011).

At first prices rose to levels that broke through the so-called ‘inelastic’ price response of consumers and contributed to recession in consuming countries. This effect continued even when economic growth resumed. The share of oil in the world energy market fell by 10% between 1979 and 2003. The price fell rapidly from the 1980 peak until 1986, when competition between Saudi Arabia and other exporters reached a kind of equilibrium: Saudi Arabia would no longer absorb most of the fall in demand, and negotiations on OPEC quotas would share the structural surplus among OPEC members.

Figure 3 shows the record. The share of oil in the world energy market has declined continuously since 1973, most abruptly after the two oil shocks of 1973–74 and 1978–79. It is simple to see this as the period of two hikes in price, of which the first was not sustained and the second may not be, as oil is replaced by other energy consumption and oil production is stimulated by investments made in the high-price period.

The next stage for OPEC

From 1986 to the end of 2004, crude oil prices averaged just over \$31 per barrel (2011 dollars), though with wide variations, from \$18 to \$41. It would be a mistake to view this average as some kind of norm. From 2005 to 2011 crude oil prices have averaged \$85 per barrel (in 2011 dollars) – more than double the average of the previous 20 years, and with less variation. The obvious explanation is that, except for the years of the world economic crisis in 2009–11, demand has now more or less caught up with supply capacity. Before 2003 capacity exceeded production by around 3 mbd, and in the early 1980s the excess may have been as high as 6 mbd as demand collapsed after the 1978–79 oil shock and subsequent recession.²⁹ The OPEC Secretariat, in its 2012 *World Oil Outlook*, projected an increase from 4 mbd in 2011 to 8 mbd over the medium term (to 2015).³⁰ This includes the 1.5 mbd Saudi Arabia chooses to hold as a strategic reserve (less than 2% of world production). This projection noted the risk of lower world economic growth. Higher excess capacity, and weaker prices, could result.

This was a period when there was a structural surplus of oil production capacity, and a perception of abundance, caused by the combination of substitution for oil and the decline in energy demand following the global economic recession of the early 1980s. During this period the members of OPEC played an important role in agreeing quotas to allocate that surplus capacity so as to avoid free-for-all competition that would cause the price to crash. They performed this role with varying degrees of success, as the fluctuations in price showed – though these might have been greater without the influence of OPEC. A secondary role – more valued by some members than others – was to achieve some moderation of price increases (to protect future demand) by relaxing quotas when demand temporarily outran supply. Both roles depended on the existence of spare capacity. OPEC members did not (and do not) discuss or coordinate the investment plans that would create new capacity, so the potential for longer-term competition remains: members’ shares of the available market were not (and are not) in proportion to the potential capacity that their reserves could support.

OPEC coordination of supply from surplus capacity will remain important because the latter is likely to grow in the medium term. Current OPEC investment plans imply increases in capacity of around 4 mbd by 2015, compared with an increase in offtake of 2 mbd in the OPEC reference case.³¹ Half of this is accounted for by increases in OPEC consumption: the rest is at risk from changes in the world economic situation.

As ‘unconventional’ oils from new areas outside OPEC grow in importance, they will also experience the fluctuations in oil demand that now fall entirely on OPEC. Many of these new supplies are from oil sands, tight oil and similar sources where individual wells have low production rates which decline rapidly if drilling is not sustained. When prices fail to cover these variable costs, drilling will slow and production will fall. Similar responses can be expected in mature reservoirs, both within and outside OPEC, where the productivity of individual wells has fallen and production is supported by more

29 These estimates are not exact.

30 OPEC Secretariat, http://www.opec.org/opec_web/en/data_graphs/646.htm, accessed 21 August 2012.

31 OPEC *World Oil Outlook 2011* (WOO), 2012, Table 1.8.

drilling. The rapid growth forecast for unconventional oil (shale oil, tight oil and natural gas liquids)³² also entails a succession of new projects, implementation of which will be slowed when prices are weak.

These developments challenge the traditional forecasting procedure used by many institutions, which is to forecast demand and non-OPEC supply, assuming full use of non-OPEC capacity, and then calculate the balance as a 'call on OPEC'. First, the definition of spare capacity is becoming too simplistic: one needs to imagine a more continuous supply curve, in which the effect of price on demand interacts with capacity created earlier, and the use of that capacity to offer crude to the market is the result of the behaviour of producers – including those who coordinate their actions through or with OPEC. Secondly, in the medium term (5–15 years) it is growing OPEC capacity (though not necessarily its use) that is likely to be more or less fixed and predictable: the result of members' policies, reserves, depletion policy and investment. Capacity for supply of liquids outside OPEC is less certain, because of its dependence on new projects and technologies.

At the same time medium-term demand will be affected by the length and depth of the economic slowdown and the rate at which new technologies to avoid demand – e.g. by switching to fuel-efficient vehicles – are taken up. Now that these are on offer everywhere they too will respond to oil prices. So we are entering a period where the 'call for new supplies' will be heard outside OPEC by the many suppliers of new oil, natural gas liquids, biofuels and oil-avoiding transport technologies. For them there is no regulator except price.

Through its ability to regulate over a third of the world's oil production, OPEC will continue to have an influence – which no other institution can equal – on what that price will be in the short and medium term. The problem, as always, is that the interests of members are not identical. Their needs for current revenue differ, and their long-term potential for increasing export volumes differs according to their reserves and growth in domestic consumption. In the longer term, limits are becoming obvious as a result of the reactions to the price increases that have occurred since 2003. The OPEC secretariat, in its 2011 *World Oil Outlook*, notes that 'at real prices around \$110/b, practically the entire non-conventional resource base is already economic in terms of long-term supply'.³³

New era

A simple model

One can broadly characterize a model of oil price trends as a 'double envelope in a box', with OPEC supplying about 50% of the world trade.

Competition (or restraint of competition) within the OPEC envelope sets the international crude price in the short term. In the medium term the price coming out of the short-term envelope has to fit in the medium-term envelope of prices covering the costs of investment in non-conventional crude and new remote or deep provinces. The medium-term envelope has to fit in the long-term box, which determines the share of oil in the global energy market in competition with other fuels or more efficient consumption technology, for example in vehicles. In the longer term the oil price envelope also affects the absolute size of the oil market through its influence on total energy prices and the demand for energy – the size of the 'box'.

We are therefore in an era of new fundamentals for the oil market.³⁴ OPEC oil is in competition (but at a higher price than before) with new sources of petroleum liquids outside OPEC, such as the deepwater and pre-salt deposits in the Atlantic, shale oil and oil from tight deposits, and liquids from shale gas. Oil as a fuel is in competition with alternatives: in the transport market it competes with the automobile industry for more efficient cars (driven by climate policy standards) and biofuels; in the industrial market in many countries it competes with gas, where there now appears to be scope for substantial increases in supply without the increases in price that would eliminate its competitiveness.

³² Ibid., Table 1.9.

³³ Ibid., p. 30.

³⁴ John V. Mitchell, *A New Era for Oil Prices*, Chatham House, 2006.

Oil-exporting countries in the future

The problem for the governments of oil-exporting countries dependent on oil revenues has therefore changed: there are new constraints, at the same time as their need for oil revenues is being increased by the need to meet new political and social demands. They cannot rely on continuous or even major increases in price beyond the levels that were current at the beginning of 2012. Nor can they expect perpetual increases in export volume.

Where countries have foreign oil investors there is little scope for governments to improve the terms on which profits are allowed to foreigners, and in some countries such as Saudi Arabia, Kuwait and Mexico there is no foreign participation in oil projects. Governments offering projects have to compete with other countries where there are more diverse opportunities than ever before, supported by new technology, new discoveries and the prospect of a price that at least is likely to remain higher than pre-2003 prices.

Moreover, because domestic consumption in most oil-exporting countries is increasing, their export volumes will decline when production approaches limits set by either policy or resources. Attempts to restrain consumption by increasing local prices have generally stalled because of governments' sense of economic fragility, although there have been some increases, notably in Iran.

The last possibility for increasing government revenue is therefore to reduce dependence on oil export revenues, broadening the tax base while diversifying the economy. This is the new field in which the oil-exporting countries will need to compete: to use less oil.³⁵

35 For a case study on Saudi Arabia, see Glada Lahn and Paul Stevens, *Burning Oil to Keep Cool: The Hidden Energy Crisis in Saudi Arabia*, Chatham House Programme Report, December 2011.

4 Gas for Power

Key points on gas

- Recent and probably future increases in gas reserves (mainly from shale gas) have the potential to support large increases in gas use. However,
 - The scope for the expansion of gas in power will be limited by policies to promote renewables, to protect local coal industries, and to promote or run down nuclear generation;
 - Energy security policies may limit the expansion of gas use where it would increase imports;
 - Regionality of markets will continue, defined by policy, logistics, legacies and new frontiers; interregional trade (mainly by LNG) will loosely link prices in different markets.
- The key question is to find a price for gas in each region that is low enough to expand demand and high enough to call forward increased supply to that region. Because of uncertainties about policies, price and market, costs are critical to producers.
- In countries or regions where the new sources of supply lead to cheap gas, as in North America, the gas industry and the vehicle industries are likely to promote the use of gas in transport – for instance compressed natural gas (CNG) in commercial fleets.

This chapter describes opportunities and challenges that the gas industry is now facing in its most important market: roughly 40% of world gas sales are used to generate electricity.

The problematic outlook

Gas is the second most important fuel (after coal) for power globally and is expected to remain so. Its importance differs greatly between countries according to the availability of local supplies of gas. The potential for increasing gas supply in North America has been transformed by the development of techniques for extracting gas from shale, and it is possible that similar transformations may eventually occur in some other countries. Shale gas contributed 23% of US natural gas production in 2010, and its share could quadruple by 2035.³⁶ Expansion in the US, and in other countries with potential shale gas resources, is dependent on the prices available locally, and on overcoming a variety of environmental challenges related to emissions of methane, disruption of the surface, risks to supply and the potential for increasing the probability of earthquakes. Policies to manage these risks had been proposed by the IEA³⁷ but it is far from clear that these will be adopted quickly in the major potential shale gas areas, or that the necessary infrastructure and technical support can be made available there as quickly as in the US. There have also been significant discoveries in new areas such as East Africa offshore. What is problematic is whether demand will expand to match the new supply potential for the proportion of gas in total world energy consumption. This depends on the progress of electrification and the share of gas in it. This in turn

³⁶ DOE, EIA, AEO 2012.

³⁷ IEA, 'Golden Rules for a Golden Age of Gas', May 2012.

is affected by government climate change policies, which may lead to a ‘Golden Age of Gas.’³⁸ Under such a scenario, gas use would be 10–15% higher than under current policies, with the main increase in sales to the power sector and in China.

Under the 2011 IEA scenario of current policies to 2030,³⁹ gas barely maintains its share of input to the global power sector (Table 4).⁴⁰ However, the share of electricity increases in final energy consumption, indirectly increasing that of gas through its input to electricity generation. The share of oil falls in both measures, but that of coal increases. Taking gas, oil and coal together, the share of fossil fuels in the power-generating sector falls, but there is no fall in the share of fossil fuels in final energy consumption – again because of the increase in electricity use.

Table 4: Share of primary fuels in the world power sector (% , rounded)

	2009	2030	Change
Gas	22	21	-1.0
Coal	47	49	+1.5
Oil	6	2	-3.5
Renewables	4	8	+4.5
Nuclear	15	14	-1.0
Hydro	6	6	-0.5

Source: International Energy Agency, WEO 2011, Current Policies. Reference case projections by the US DOE in Energy Intelligence Agency, *International Energy Outlook 2011* are similar.

Renewables include biomass and waste.

Uncertainty of future policies to reduce carbon emissions

Current policies to reduce carbon emissions are unlikely to achieve the perceived objective of limiting global climate change to less than a 50% probability of 2°C warming. Stronger policies will be necessary for this, and many countries are likely to consider such policies when the current economic climate improves, especially if evidence for global warming becomes more persuasive. The experience of inefficiencies and distortions arising from very specific mandates may lead to more general policies with greater freedom for industries and consumers to find the most efficient ways of reducing carbon emissions. Continuing investment by different industries in a variety of technologies will offer more options than those now recognized. Governments will still have to face the dilemma that restrictive carbon policies will need to be accepted politically without any visible short-term result. Demand for electricity and for the primary fuels used to generate it is likely to grow more slowly than in inertia-driven ‘current policy’ scenarios. Higher electricity costs are likely where markets are created or sheltered specifically to promote renewable or nuclear power rather than being guided by more general restraints on carbon emissions. Higher electricity prices will provide an incentive for stronger policies on energy efficiency to reduce the demand for electricity. ‘Efficiency’ will be supplied by businesses offering hardware and software to control consumption of electricity at the point of use. Government mandates are likely to reinforce the growth of the ‘efficiency’ businesses even more strongly if renewables develop more slowly and carbon capture and storage (CCS) does not achieve widespread application in coal-fired generation.

For the power industry, increasing use of gas is a hedge against these uncertainties because of the availability and cost, and the known technology involved.

38 Ibid.

39 In the IEA WEO 2011, which projects to 2035.

40 This report uses numbers from a variety of sources, not always consistent. Figures for the indistinct future are therefore rounded.

Shale gas

The technology for producing gas from shale deposits, ‘tight’ gas deposits, and coalbed methane has developed to the point where shale resources can be recognized as a long-term source of reserves. The US Securities and Exchange Commission (SEC) now accepts ‘proved’ reserves of shale gas (technically capable of economic production at the year’s average price) as part of a company’s reserves. Potentially recoverable resources of unconventional (shale) gas are at least roughly double the reserves of conventional gas,⁴¹ and are more widely distributed across regions.

It may take time to resolve environmental difficulties, and to spread the technology, management, necessary infrastructure and supporting services outside the US. However, there is little doubt that the world’s gas resources can support higher levels of production than were envisaged five years ago, probably without upward pressure on prices⁴² and without justification for the premiums currently paid in Asian and continental markets, relative to North American prices.

Uncertain role of imports

Only 30% of the world gas consumption is supplied by imports, mainly from neighbouring countries. There are large differences between costs and availability in different regions, but there are common difficulties in building new markets with imported gas:

- The high cost of transport relative to the value of the gas;
- Probably unsustainable differences between pricing systems based on short-term, commodity markets at hubs where suppliers compete (US and UK), and long-term contracts at prices linked to the short-term commodity prices for crude oil (continental Europe and Asia);
- Security concerns about dependence on a dominant supplier: Russia for Europe, Qatar for some Asian markets.

In some scenarios, the pricing problems are mitigated by a growing, diversified and competitive LNG trade which will weaken the links with oil.

Nevertheless, international trade in gas is likely to remain the balancing, rather than the driving force in setting local and regional gas prices. Small changes in an important region will have a disproportionate effect on the international balance – especially if market structures prevent the transmission of these prices to a different market.

Expanding the demand for gas

The question is therefore whether the demand for gas can be expanded beyond the inertia scenarios at a price that will expand the supply.

Seven groups of countries, shown in Table 5, account for three-quarters of the present market for gas in the power sector. Russia, a net exporter, is the largest, with over half its electricity fired by gas. Table 5 shows the current pecking order and how shares are expected to shift under the IEA’s ‘current policy’ projections, with traditional gas markets diminishing in importance and Asian and ‘other’ (mainly developing economies’) markets rising. In important countries, as shown in Appendix 3, the position of gas in the power sector will be the result of competition with coal in the space between renewables (defined and supported by government policies), and nuclear, likewise defined but not necessarily supported by government policies. Coal in some countries will also face the cost of environmental restrictions on mining and on emissions (other than greenhouse gases). Within this framework, the

41 EIA, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*, April 2011.

42 IEA, ‘Are We Entering a Golden Age of Gas?’, Special Report, June 2011.

position of gas relative to coal depends mainly on local availability and costs. Under current policies, including a strong bias towards renewables in Europe, China and the US, and towards nuclear energy in Russia, the outlook for expansion of gas demand as a share of energy into power is focused on developing countries, particularly in Asia, as Table 5 shows.

Table 5: Power-sector markets for gas

	Gas used in power sector, 2009 (bcf)	Gas used in power sector, 2009 (bcm)	Share of world gas supplies used for power, 2009 (%)	Change in share 2009–30 (%)
Russia	13,485	382	34	-5
US	6,778	192	17	-5
EU	5,436	154	14	-1
Japan	2,047	58	5	-1
India	918	26	2	2
China	635	18	2	5
Others	10,025	284	26	5

Source: International Energy Agency WEO 2011, Current Policies.

These projections may understate the potential for gas to enter the transport market in the medium term as a fuel for use in vehicles and ships, and its potential as a fuel for further electrification of the transport system.

Uncertain implications for investment in gas

The scope for investment in the production and supply of gas for the power market is subject to many uncertainties:

- Policy on expansion of nuclear power (already small in relation to other sources), which is limited by the shutting down of plants in some countries, and by the continuing problem of credible waste management programmes;
- Policy on the expansion of intermittent renewables (solar, wind). These create a demand for backup generating capacity and correspondingly flexible supplies of fossil fuels, either gas or coal;
- A possible shift in the competitive balance between gas and coal in the US and China: coal currently has price advantages but is disadvantaged in policy terms by the lack of a convincing story for rapid and economic deployment of CCS;
- Potential limits to the expansion of the markets for Asian gas in a scenario in which China leads with renewable supplies, and shale gas in the longer term, and Japan achieves even greater efficiency in the use of electricity.

Implications for the industry

The scope for expanding the use of gas in power depends on policies which favour or penalize specific types of fuel input, rather than regulating the overall output of CO₂ through allowances or taxes: overall emission restrictions or carbon prices will favour gas over coal but input policies may also favour renewables over gas. Other policies that may affect the expansion of gas in power are those to protect local coal industries, and to promote or run down nuclear generation; and energy security policies that may limit the expansion of gas use where it would depend on expanding imports. Regionality of markets will continue, defined by policy, logistics, legacies and new frontiers; interregional trade (mainly by LNG) will loosely arbitrage prices between gas markets. The key question is to find a price for gas in each region

that is low enough to expand demand and high enough to call forward increased supply to that region. Because of uncertainties about policies, price and market, costs are critical to producers. Gas-importing companies will look for diversity of supply and flexibility of pricing regimes. Generators in Asia and Europe who currently import gas on long-term contracts linked to oil may look for prices linked to fuels which will compete in their power market in the future: in some countries (e.g. the US) this will be coal, in some (e.g. Europe) it will be LNG supplied from a region where gas competes with gas. The outcome may be a hybrid system with some trade where price is linked to oil and some where it is linked to LNG short-term markets.

With nuclear limited, and renewables already stretched to 2030, in the longer term increased use of gas in the power market may be the only basis for more electrification, e.g. in transport.

In countries where the new sources of supply lead to cheap gas, as in North America, the gas industry and the vehicle industries are likely to promote the use of gas in transport – for instance compressed natural gas (CNG) in commercial fleets.

5 Upstream Resources and Reserves

Key points on upstream resources and reserves

- Technology is the key.
- 'Peak oil is' a misleading idea. The potential for future oil production depends on resources being converted into reserves by the application of technology, economics and investment. Oil reserves have more than doubled since 1980 – more than the increase in production: oil is not running out.
- A variety of new technologies is creating new reserves outside the traditional oil-exporting countries: in pre-salt reservoirs, ultra-deepwater, impermeable deposits (such as shale), accessed by a combination of horizontal drilling and 'fracking'.
- Reserves are also increasing in many traditional exporting countries, with new technology focused on their particular conditions, e.g. enhancing ultimate recovery from mature reservoirs.
- State-controlled companies control nearly 90% of current oil reserves, but in the state-controlled sector 50% is open to the private sector in various forms of cooperation with state companies on the terms set by the country concerned, and with specific technology needed by the state company.

Public debate is often focused on estimates and surveys of 'recoverable' oil and gas reserves – usually without reference to the economic and technical factors involved in their definitions. These are often confused with the geological concept of finite or 'exhaustible' resources – for which there are few, and more uncertain estimates.⁴³ This chapter attempts to correct these misperceptions.

The resource base

While resources are determined by geology and by definition finite, reserves are the result of the industry's activity. For the oil and gas industry, additions to 'recoverable' reserves are like research and development in a non-resource industry. They generate opportunities for future investment. Reserves increase as a result of new discoveries, and 'grow' as a result of better understanding of known reservoirs, as well as the application of new or improved technology to increase the proportion of the oil in the reservoir that can be economically produced (the 'recovery ratio'), which varies between 10% and 60% depending on the type of oil and characteristics of the reservoir. Typically, primary recovery rates may be around 20%, a further 15% to 25% may be added by secondary recovery (waterflood and gas injection) and more by enhanced oil recovery (EOR) (e.g. waterflooding, or injection of gas, steam, CO₂ or chemicals).⁴⁴ Reserve estimates may also be revised downwards as a result of better understanding, or additional costs resulting from new requirements for avoiding the risk of environmental damage.

43 There is a detailed discussion of these concepts and the methodology used in the World Energy Council (WEC) *2010 Survey Of Energy Resources*, Chapter 2.

44 P. Zitha et al, 'Increasing Hydrocarbon Recovery Factors', Society of Petroleum Engineers White Paper, July 2011, <http://www.spe.org/industry/docs/recoveryfactors.pdf>.

What are reserves?

Broadly speaking, *proved* ‘recoverable reserves’ means resources where the presence of hydrocarbons has been identified, and confirmed, either by drilling or by the application of well-recognized techniques of estimation, where the technology exists for the production of the reserves, and where that production would be economic at some identified price. Like all definitions of reserves, they are estimates.

Beyond ‘proved’ reserves are ‘probable’ or contingent reserves, where oil (or gas) has been identified and there is a 50% or greater probability that the criteria of proof will be met.

Beyond that are ‘possible’ reserves, where hydrocarbons have not yet been confirmed.

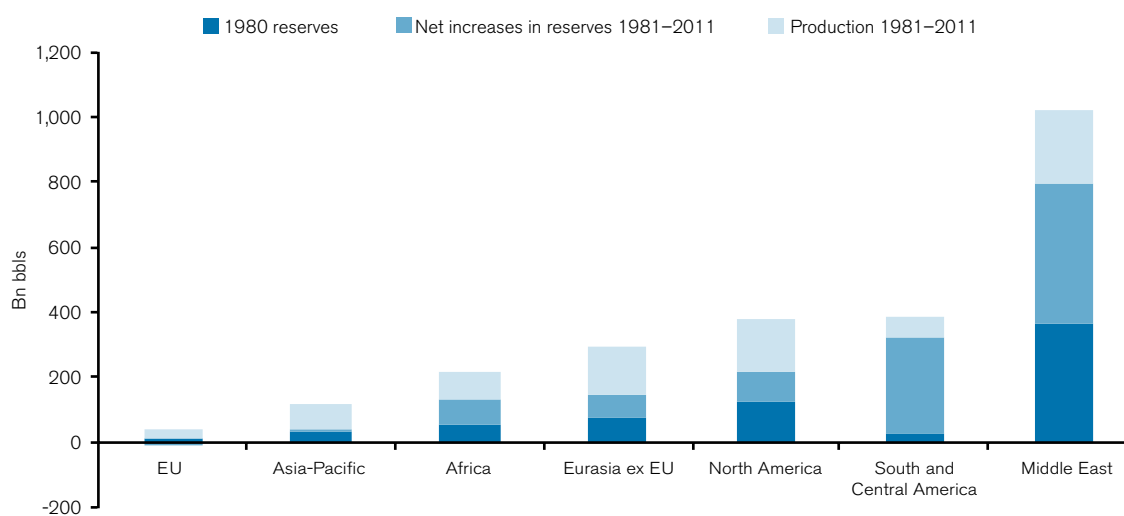
These categories can be mapped on to probability distributions, further subdivided and reconciled to the widely used systems proposed by the Society of Petroleum Engineers (SPE).⁴⁵ Definitions of ‘oil’ and ‘gas’ are being adjusted to reflect the growing importance of so-called ‘unconventional’ oil and gas as well as more complex economic conditions for developing resources.

Financial regulators in the US Securities and Exchange Commission (SEC), the UK and Canada have rules for companies to report proved reserves. Government agencies in the US (US Geological Survey), Norway, Russia and China provide countrywide estimates and systems that differ in detail but can broadly be reconciled with the SPE system.⁴⁶ World and country surveys, such as the OPEC *Annual Statistical Bulletin*, the widely used *BP Statistical Review, World Oil* and the *Oil and Gas Journal* generally interpret these data to show as ‘proved’ reserves those estimates ‘which geological and engineering information indicates with reasonable certainty can be recovered from known reservoirs under existing economic and operating conditions’.⁴⁷ The BP statistics include liquids associated with natural gas (NGLs) as oil reserves: some agencies separate them.

Trends in oil reserves

From 1980 to 2011, the world produced more oil (including NGLs) – 795 billion barrels (bn bbls) – than the reserves had been thought to be in 1980 (683 bn bbls), while 1,774 bn bbls were added. While production increased by 30%, reserves remaining for future production more than doubled to 1,653 bn bbls with net increases in all regions and countries except Indonesia, Mexico, the European Union and the US (see Figure 4). Local depletion was more than offset by global additions.

Figure 4: Movement in oil and NGL reserves, 1980–2011



Source: BP *Statistical Review*, 2012.

45 World Petroleum Council, ‘Guidelines for Application of the Petroleum Resources Management System’, November 2011.

46 Society of Petroleum Engineers, Oil and Gas Reserves Committee, ‘Mapping’ Subcommittee Report, December 2005.

47 BP *Statistical Review*, 2012, Note.

Since 2000, 290 bn bbls have been produced and 655 bn bbls added to proved reserves so that net growth in proved reserves has been just over 50%, while production increased by only 10%.

Historical trends do not fully indicate the potential scale of development of technologies such as horizontal drilling when combined with hydraulic fracturing to develop reserves from shale and ‘tight’ oil deposits.⁴⁸ The US DOE estimates an increase in US tight oil production of between 0.8 mbd and 1.8 mbd from 2010 to 2020. The consultancy Wood Mackenzie estimates an increase of over 3 mbd.⁴⁹

Adding reserves in most of the western hemisphere depends not only on the technical achievement and risk-taking capacity of the private-sector companies, but on the financial and policy framework within which they operate.

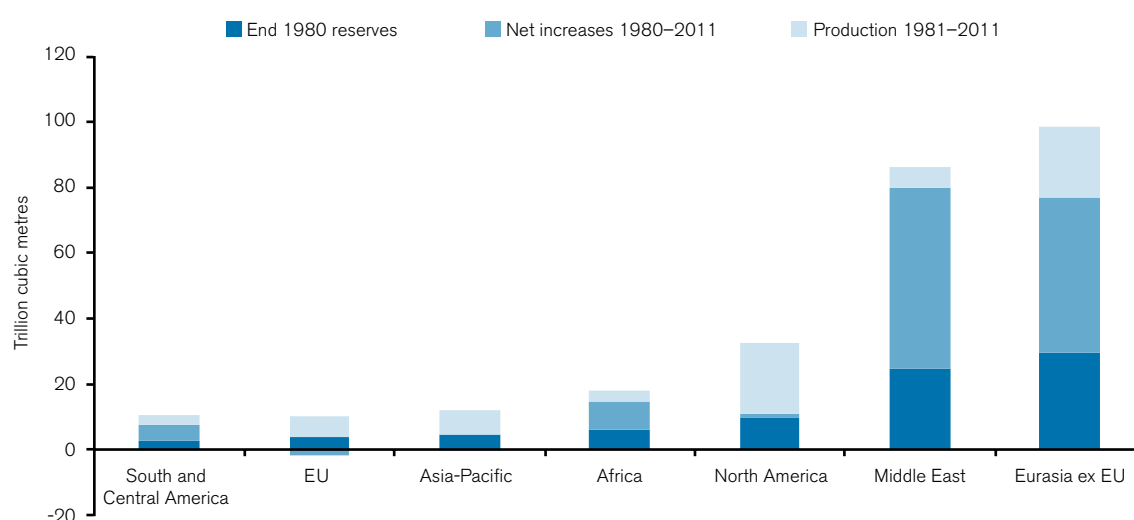
The state companies of the Middle East have a different problem. For state companies limited to their own territory, depletion is limited by whichever is the lower figure: technical capacity or the conservative depletion policies of their governments. Middle East producers have more than replaced depleted reserves, mainly by a combination of discoveries, improved recovery and new reservoir development. Since 2000, net proved reserves have increased by 23%, while production has increased by 10%. Even without any future additions, 2010 rates of production could be maintained for nearly 80 years – longer in the major producers.⁵⁰

Trends in gas reserves

Since 1980 estimates of world recoverable reserves of gas have more than doubled; this is slightly more than the increase in production. Reserves have increased in all regions except North America where they have remained stable thanks to the addition of shale gas as a recoverable resource, and the EU, where they have fallen. The largest increases, almost entirely of conventional gas, have been in the former Soviet Union and the Middle East (see Figure 5).

Potential growth in production does not necessarily match that of reserves. Location is more important for gas than for oil because the higher cost per unit of energy separates gas markets more. Gas reserves are also more concentrated: Russia had 40% of gas reserves outside the Middle East at the end of 2010, while Qatar and Iran had nearly 75% of the gas reserves in the Middle East.

Figure 5: Movement in gas reserves, 1980–2011



Source: BP Statistical Review.

48 ‘Tight’ oil and shale oil have different properties, though both are derived from deposits in shale.

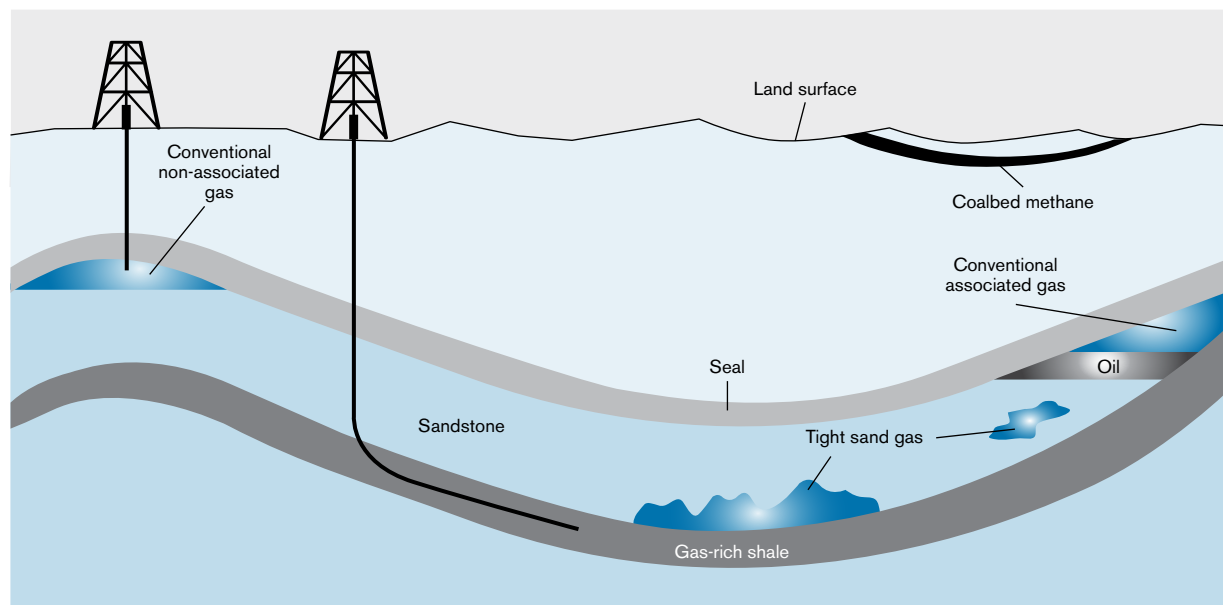
49 Petroleum Economist, *Unconventional Global Intelligence*, <http://www.petroleum-economist.com/Article/3079993>.

50 BP Statistical Review 2012.

Shale gas

The combination of hydraulic fracturing and horizontal drilling is transforming estimates of gas recoverable from shale and low-permeability rocks. Figure 6 shows schematically the different sources of conventional and non-conventional gas.

Figure 6: Schematic for gas resources



Source: US Energy Information Administration and US Geological Survey.

So far these additions have mainly taken place in North America. Evaluation of known shale deposits in other countries – China, Ukraine, Russia, Poland, Australia, Argentina, Saudi Arabia, Iran and Algeria – may lead to significant additions in the future.

However, future additions, even in the US, are very uncertain: the size of the ultimately recoverable resource is not known, and the proportion that can be economically recovered depends on economic as well as technical factors. One interesting effect of such a large resource being available incrementally to a diversity of producers at a diversity of costs is that the US shale resource can be expected to be sensitive to gas prices.⁵¹ The production technique depends on intensive drilling, which can be accelerated or slowed down according to market conditions and expectations.

Development is likely to be slower outside the US where two decades of experiment and investment led to the current production levels of nearly 4 tcf.⁵² The original advantages in the US remain: well-defined rights to properties, a diverse private sector including companies prepared to invest in both large and small projects, a well-established pipeline system near the main deposits, and an immense technical resource. The process requires very large numbers of wells and competent staff, as well as the hardware to deploy these.

In China, which has the largest shale gas potential resources outside the United States, both exploration and development have been slower than government targets. Some areas have been opened to licensing (for Chinese companies), but a large part of the resource is within the licence areas of the three main state companies. Foreign companies are involved in technology contracts for exploration in some of these areas but there is at the moment no indication of how far foreign companies would be able to bring their technical capabilities to invest in shale gas development in China.⁵³

51 US DOE, *Annual Energy Outlook 2011*.

52 Paul Stevens, *The 'Shale Gas Revolution': Hype and Reality*, Chatham House Report, 2010.

53 Fan Gao, *Will There be a Shale Gas Revolution in China by 2020?*, OIES, 2012.

The main effect of the shale gas ‘revolution’ outside North America remains likely to be on the long-term expectations – beyond 2030 – for the global availability of gas and for its geographic distribution.

New exploration or ‘reserve growth’

Volumes of new oil and gas resources identified by exploration efforts have been falling since the early 1980s. In the last decade new discoveries have broadly stabilized, but the world has not been running out of oil or gas, nor of ideas on where to find new hydrocarbons. However, even with no further discoveries or additions, the remaining reserves would correspond to 54 years of current consumption of oil and NGLs and 64 years of gas;⁵⁴ and in reality the industry can expect a longer life. Reserves will last longer because more oil will be found in existing deposits, there will be new discoveries, and consumption will decline as prices rise, inducing more economic use of oil (in transport, for example, as noted in Chapter 2) and the development of substitute fuels. Crucially, there will be more additions to reserves as:

- Estimates of the world reserves grow through better understanding of prospective and existing reservoirs as a result of additional analysis, new technology becoming available, and improvements in the general price and cost environment. The US Geological Survey mean estimate for reserve growth outside the US is 665 bn bbls, equivalent to 40% of end-2011 reserves of oil and NGLs.
- Technology will continue to open the way for the extraction of resources in tight rocks and very deepwater, sub-salt and pre-salt formations, and of methane from coal seams, as well as deepwater exploration in the Arctic regions, to name a few. Unlike tar sands and heavy oil, these are not necessarily more carbon-intensive than conventional resources. Many of these potential reserves are located outside the Middle East in regions not dominated by state control of the oil industry (see discussion in Chapter 6).

Technology

The industry’s future depends on continuous technological improvement, but expert commentators have noted that international oil and gas companies (apart from oilfield service companies) are slow to adopt new technology: twice as long as in medicine, according to a Shell/McKinsey study.⁵⁵ This lag, however, has been closing as more exploration technologies are IT-based.

3D seismic mapping, which has transformed the exploration process, was first used by Exxon in 1967. Its development depended heavily on increases in computing power and reductions in computing cost generated outside the industry. It was 20 years before more than half the seismic surveys in the Gulf of Mexico and the North Sea used 3D seismic.

Horizontal drilling, which has dramatically improved the productivity and reduced the cost and environmental impact of producing wells, has developed over 30 years with the help of two specific ‘breakthroughs’ – a downhole steerable motor controlled from the surface, and technology for measuring reservoir characteristics at the drill tip while drilling.⁵⁶

Fracturing technology has a long history; the first experimental hydrofracking was undertaken on a reservoir basis by a subsidiary of Amoco in 1947. In the US, the technology was supported in the 1970s by the federal government through work at the Sandia National Laboratories for micro seismic imaging and through tax incentives and cash for a variety of private pilot plants. Fracturing via horizontal wells was initiated in the Barnett Shale in 1991 with federal government support. Mitchell Energy – mainly a service company – went on to apply and develop the technology. Many technological elements have been patented and others are still the subject of innovation, particularly with the aim of reducing environmental impacts due to the use of water.

54 BP *Statistical Review* 2012.

55 Cited in National Petroleum Council (NPC), *Global Oil and Gas Study*, Topic Paper 26, ‘Oil and Gas Technology Development’, 2007.

56 NPC, Topic Paper 56.

One reason for the slow adoption of new technology by major operating companies may have been aversion to the risk of applying it in the large projects typical of their operations. There are many other reasons such as economics, and field depletion and reservoir management practices. Some small companies have been more aggressive. The role of Mitchell Energy in developing hydrofracking technology for shale gas is a classic example, though the initial R&D was supported by government rather than companies. Some national oil companies have been aggressive, focusing on the particular needs of their geological situation – for example, the production of heavy oil in Venezuela, and deep offshore operations in the North Sea and the South Atlantic. National companies may also be less concerned with short-term economic costs.

At the same time as the results of new exploration became less fruitful and harder to monetize, major international oil companies were reducing their R&D budgets to focus on shorter-term technical support, with the idea that new technology could be acquired from oilfield service companies. These in turn have increased their expenditure in recent years. Leading service companies have established and expanded their own research centres, linked closely to their potential business in particular geographic areas or technical specialties.

Definitions of R&D vary, so that comparisons are rough, but it seems that in 2010 the top 12 private-sector oilfield service companies' expenditure on R&D was about 1% of their market capitalization. For the international operating companies the figure was under 0.5%.⁵⁷ The outsourcing of R&D has its critics, who ask:

- Are the operating companies retaining sufficient in-house expertise to track new technological developments and appreciate their potential relevance?
- Do the oilfield service companies prioritize technologies for which they envisage many customers, while leaving more focused ideas untested?
- Do the operating companies sufficiently integrate their evaluation of technical risks with management and monitoring techniques needed to minimize the risk of Macondo-type disasters?

Implications for the private sector

Chapter 7 discusses investors' perceptions of the traditional international company ability to 'bring technology' (at least the management of it) in seeking economic partnerships with state companies, especially in countries that are small, new to the industry and lacking local scientific and technical support.

Implications for government policy

Governments face the question of whether the combination of market structures and government institutions in their country provide the incentives for adequate development of new technology and access to it for the operators. In some countries, this may depend on access to technology from beyond national borders. In some, where there is a technological base, oil- or gas-related research is coordinated through specific agencies (such as the US Department of Energy and the Research Council for Norway's OG21 programme). In others, such as the UK, it appears to be left mainly to the private-sector companies through normal tax allowances and normal university funding. Where the industry is under government control additional support may be established separately (as in Saudi Arabia's King Abdullah Petroleum Research Center) or as a part of the state company – as in Brazil through the Petrobras Research Centre (CENPES). The private sector may also commit to local investment in research and professional training, as in BG's initiative in Brazil and the Schlumberger research centres in Russia and China.

For smaller producing countries with state companies the question is whether there is sufficient technical expertise within the licensing state authority to ensure that appropriate technology is found for their specific problems through the joint ventures with international companies that will be their main access to technology.

⁵⁷ Extracted from Joint Research Centre, EU Directorate for Research and Innovation, 2011 EU Industrial R&D Investment Scoreboard.

Oil-dependent economies

Oil dependency is often thought of as a problem for oil-importing countries. In fact it is more problematic for those exporters (as in the Middle East) that lack diverse economies.

The Middle East and North Africa (MENA) has 48% of the world's currently known (end-2011) oil reserves⁵⁸ and is estimated to contain about 20% of the world's undiscovered conventional oil resources outside the US,⁵⁹ equivalent to about 13% of MENA reserves at end-2010. There is no published estimate for reserve growth in the region.

Apart from Iraq, major Middle East oil exporters limit their production in order to conserve resources for the future (and in Iraq the question will arise). Most have a record of adding reserves by improved technology to replace depletion – and more – so that a long plateau of potentially higher production can be supported.

However, exports will be reduced by ever-growing domestic consumption as production approaches the limits imposed by the combination of policies with available reserves. Government fiscal and foreign exchange revenues will fall and the oil-dependent economies will shrink. For some Middle East exporters this decline in revenues may begin within the next couple of decades.⁶⁰ Oil will be conserved for the future until economic diversification is adequate to replace it as a source of revenue and foreign exchange. The main constraint on short-term expansion of oil production to the limits of the resource and reserve availability is the degree of dependence of the rest of the economy on the oil sector (rather than reserves), through depletion policies.

Unless their non-petroleum economies are transformed quickly and to a surprising degree, most oil exporters in the Middle East therefore need to continue to add oil reserves – as they have done in the past – to support future production, at a higher level. Unless they do so, higher production will bring the economic transition nearer and make it more difficult.

The development of this 'dependence horizon' is a change from the decades after the second oil shock of 1979–80, when oil demand fell as a result of recession and the loss of 10% of the global energy market to other fuels. The result then was a structural surplus of production capacity, which caused members of OPEC to restrict production to support the price. With decades of oil production secure under the ground, adding even more reserves had low priority.

Principles of ownership of reserves

Property rights in mineral resources are set within the legal and constitutional history and institutions of the countries in which they exist. There are two main legal concepts: surface ownership and social ownership. The difference between them has a fundamental effect on the structure of the oil and gas industry.

Surface ownership: In some countries, including the United States, Canada, Australia and Denmark, ownership of the land surface carries with it ownership of the subsoil resources. Where the federal or state governments are owners of the surface, they are therefore also owners of the subsoil, just like private owners of the surface.

Social ownership: In the Islamic and European traditions (passed on to former colonies), subsoil mineral resources are in some form of social ownership. They belong legally to the state, or the sovereign (or even God) or the nation, with the government acting as agent or trustee. In some countries indigenous peoples claim, sometimes successfully – on the basis of treaties or practice incorporating them into a nation-state – that the agency of social ownership is the local community or tribe rather than the central government.

Social ownership also applies to subsea resources where it is exercised by national governments according to the treaties establishing the Law of the Sea (UNCLOS) or according to customary international law (some

58 BP Statistical Review 2012.

59 Based on mean estimates, excludes natural gas liquids. World Resources Project, *An Estimate of Undiscovered Conventional Oil and Gas Resources of the World*, US Geological Survey, 2012.

60 John Mitchell and Paul Stevens, *Ending Dependence: Hard Choices for Oil-Exporting States*, Chatham House Report, 2008.

states, including the US, have not ratified the UNCLOS treaties). In some areas (typically where sovereign rights are disputed) bilateral agreements establish a regime for exploration and development.

Economic rights

In social ownership, national oil or gas companies may be established as agents of the government, sometimes with regulatory powers and the ability to enter into agreements with private, including foreign, enterprises. The fiscal arrangements may vary between treating the state-controlled company as if it were a private corporation (typically where it has some external shareholders) and arrangements where the state company's budget is handled through the government budget system. In many countries there is an intermediate position in which the company is left revenues approximating to its operating and capital needs and the government simply takes the rest.⁶¹

The government may also allocate economic rights to private (usually foreign) oil companies through leases or concessions. In these cases, a wide variety of possible arrangements exists, either directly with government or with the state-controlled oil company. For example:

- 'Modern' concessions in which the state economic interest takes the form of taxes, royalties and licence fees;
- Production-sharing agreements (PSAs) or contracts (PSCs), which specify financial contributions and entitlements for the private company. These provide for sharing oil, or profits – generally under some formula that provides for the capital costs undertaken by the private enterprise, generates a minimum revenue for the state, and increases the state share with the profitability of the project. Some include 'stabilization clauses' in which the private-sector company is indemnified against adverse changes in taxation imposed by the state;
- Joint-venture partnerships, in which the state- and private-sector partners share costs and profits according to their equity interest;
- 'Risk contracts' in which the private-sector company undertakes all expenditure and is rewarded on production by a fixed fee per barrel.

All these arrangements involve state approval or intervention on development plans, budgetary processes, the make-up of operating committees, and processes for resolving disputes. Usually there are obligations for local procurement and employment, and agreements have fixed terms. Exploration and production contracts are sometimes separated.

Where there is no state company, and the resources either privately owned or leased and licensed by the state, private owners typically pay taxes related to actual profits. Royalties, levied as a percentage of the value of production, are paid to the owner of the resource.

For a private-sector company an important point is whether the terms of the agreement or contract or lease give it an economic right to the reserves, including changes in their value. In such cases the company may 'book the reserves' in its financial reports, as it assumes that there is sufficient confidence in the agreement to indicate future production potential (even though the future tax and royalty regime may be uncertain, as in the UK).

Who owns the reserves?

Oil ownership

The top 50 companies controlled 94% of world oil reserves in 2010,⁶² up from 86% in 2000; of the world's oil reserves 86% are state-owned, while the proportion under private ownership in the top 50 companies is roughly 8%: if all smaller companies are included, private-sector ownership would be about 14%.

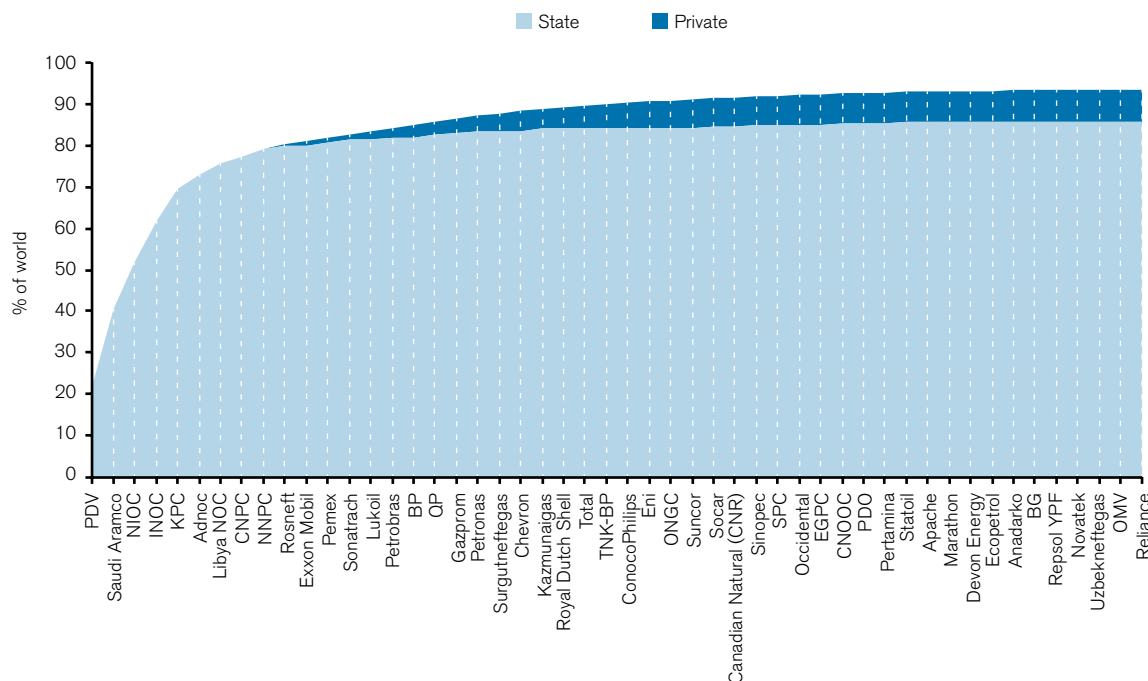
61 For a discussion of the issues involved in these relationships, see Glada Lahn et al., *Good Governance of the National Petroleum Sector*, Chatham House Report, 2007.

62 As reported in the *BP Statistical Review 2011*.

The top five companies (all state companies) hold 75% of the world's oil and liquids reserves.

Figure 7 shows an approximate distribution of oil and NGL reserves between the top 50 companies. Percentages are approximate as definitions are not always precise.⁶³

Figure 7: Ownership of world oil reserves, 2010: top 50 companies, percentage shares



Source: Energy Intelligence Top 100: Corporate Comparison Tool.

For private-sector companies reserve additions may be small in relation to the world but large in relation to the companies concerned; the reverse applies for the major state companies: their proportionately small additions matter to the world.

Worldwide, the growth of proved oil reserves has been in the state sector, while private-sector reserves have fallen. Companies with majority private ownership⁶⁴ have seen their share fall about 4% between 2000 and 2010, as the volume of their oil reserves fell by 20% (from 95 to 74 bn bbls). The state companies saw an increase of 40% in their share, with volume increases (from 859 to 1,200 bn bbls) more than three times greater than the entire private-sector reserves in 2000. Nearly a third of this increase (94 bn bbls) was due to the inclusion in proved reserves of an estimate of reserves recoverable from the Magna project in the Orinoco heavy oil belt in Venezuela.

Private- and state-sector cooperation: oil

Since 1990 there has been an increasing range of opportunities for private-sector cooperation with state-controlled companies to develop state oil reserves through different mechanisms (see Box 1). International practice, as well as the interests of the state company, tend to favour the use of a competitive process to select foreign partners, but this is sometimes sidestepped by government policy.

Terms for company investments are fluid, but the limits on both sides seem better understood than a decade ago. Changes and uncertainties have probably slowed development, but led to a more stable basis for future cooperation.

⁶³ Where the company has a state shareholding, the reserves are allocated to the state proportionately to that shareholding.

⁶⁴ This uses a slightly different definition from that used in Figure 7. Here, and in Figure 8, reserves are allocated according to the majority ownership of the company.

Box 1: Models of cooperation

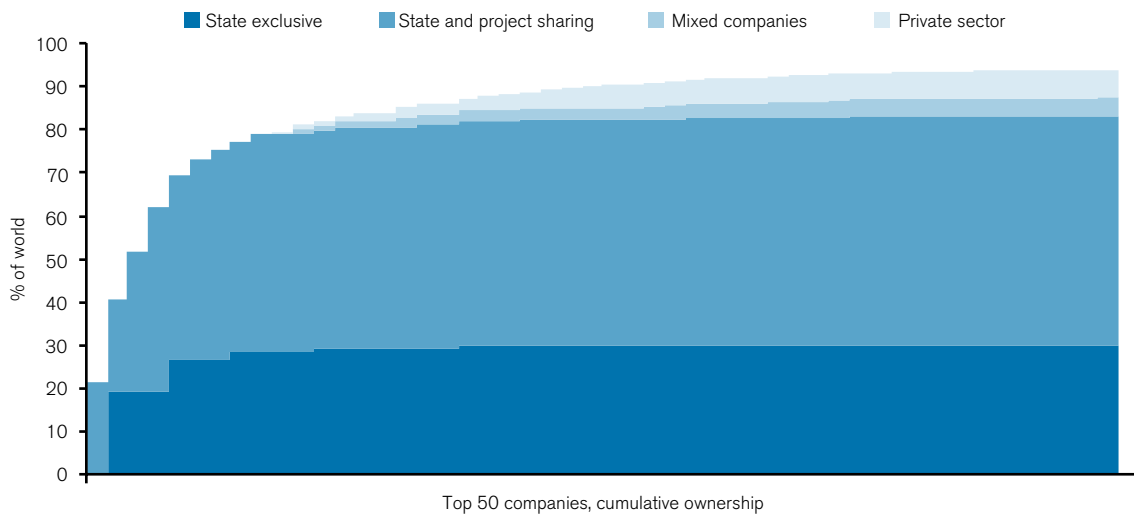
Private financial investors own and trade in shares in certain state companies which are organized as corporations, with shares traded in public stock exchanges: Petrobras, Statoil, Gazprom, Petrochina (a subsidiary of CNPC), Sinopec and CNOOC Ltd (a subsidiary of CNOOC) are examples. In these cases the government directly or indirectly holds a majority controlling interest, but accountability and transparency conform to the rules of the exchange in which the shares are traded. The private investor shares in all the profits (or losses) of the company.

- In Russia the oil sector was essentially privatized, opening the way for national and foreign private and strategic investors in Russian oil companies, such as TNK-BP. Earlier, production-sharing agreements were established – mainly in Sakhalin. In 2012, Rosneft, the state oil company, concluded large-scale joint ventures for exploration in the offshore Arctic with ExxonMobil, Statoil and ENI.
- In Azerbaijan and Turkmenistan the newly independent governments mainly followed the state-project partnership model, while in Kazakhstan this was combined with opportunities for private-sector companies to include foreign investors.
- The Venezuelan heavy oil region was opened to production-sharing and 'mixed company' agreements with PDVSA.
- The end of Petrobras' monopoly in Brazil opened the way for foreign companies to compete for new reserves, as well as for partnerships in Petrobras' projects. Petrobras was restructured to increase the shares held by private investors.
- The privatization of parts of the Chinese oil industry enables private investors to buy shares in some Chinese oil companies, particularly those with international ambitions.
- The gas initiative in Saudi Arabia created the opportunity for foreign participation (but not ownership of reserves) in exploration for new gas reserves in certain areas.
- The end of sanctions in Iraq released opportunities for development in known fields to fee-orientated contracts and for risk-sharing contracts in new exploration regions.
- There were new discoveries offshore West and East Africa, many by small foreign companies. These are being developed by international E&P companies in the absence of established and technically resourced national companies.

These developments have not always gone smoothly. Terms which started out well for foreign companies have in many cases got worse as oil prices increased, the state oil company grew more confident, or overall government policy changed. The main examples have been Russia's *de facto* nationalization of Yukos, Venezuela's renationalization of heavy oil fields (which, however, left the private sector with a substantial interest), and Argentina's nationalization of the Repsol shareholding in YPF in 2012.

Figure 8 shows a rough estimate of how oil reserves held by the top 50 companies were accessible by different mechanisms in 2010. Reserves held by smaller companies were in fact probably in the private sector in the US, Canada, Europe and Australia, so that the true share of the private sector was nearer 12% than the 6% shown in the graph. 'Mixed' companies refer to state companies in which private investors may hold shares. 'State & project sharing' refers to state companies which engage with private-sector companies in projects, joint ventures or production contracts. Figure 8 suggests that despite the very high proportion of oil reserves held by the state, there is substantial scope for private-sector companies to participate in developing and adding to them. How best to do this is discussed in Chapter 6.

Figure 8: Access to oil reserves, 2010: top 50 companies, cumulative ownership

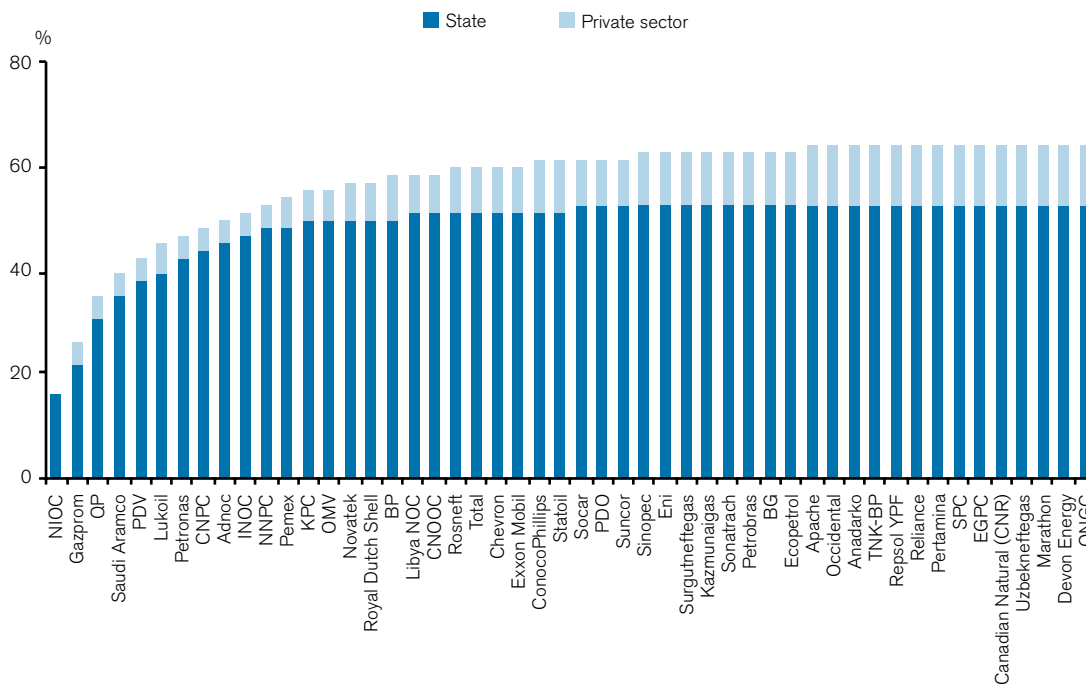


Source: Energy Intelligence Top 100: Corporate Comparison Tool, accessed April 2012; author's analysis.

Gas ownership

States dominate the ownership of gas resources, but governments own only 53% of the world's gas reserves, compared with 86% for oil. The state share is less because of the size of gas reserves in the US and Canada, where private ownership is the rule. For the same reason, the top 50 companies held a smaller share of the world total in 2010 – 64% for gas, compared with 94% for oil. Gas reserves are more widely distributed: the share of the top 50 companies has not changed since 2000 (whereas it grew for oil), and the top five companies hold only 43% of world gas reserves, compared with 75% for oil.

Figure 9: Ownership of world gas reserves, 2010: top 50 companies, cumulative ownership



Source: Energy Intelligence Top 100: Corporate Comparison Tool, accessed April 2012; author's analysis.

In contrast to oil, the private sector has held its small share (about 11%) of world gas reserves, thanks mainly to the increase in North American reserves recoverable from shale by combining hydraulic fracturing with horizontal drilling. Between 2000 and 2010, private-sector reserves rose from 277 to 326 billion cu. ft (allowing for rounding errors), while state-sector reserves rose from 3,330 to 4,060 billion cu. ft.

More countries offer opportunities for foreign investors and operators in the gas sector than in the oil sector. However many of these projects have uncertain profitability because of their commitment to supply and expand local demand at favourable prices.

Box 2: Adding oil and gas: 'oil equivalent'

Companies whose oil reserves are falling while their gas reserves are rising have developed the habit of headlining their reserves in terms of 'oil equivalent' (OE). Equivalence is usually based on thermal equivalence at the point where the fuel is delivered to the market. Though this varies for different types of crude oil and gas with different properties, a typical formula for general analysis is that a billion cubic feet of natural gas is thermally equivalent to 190,000 bbls of oil. However, this does not signify economic equivalence. The value of the energy embodied in oil (a large part of which enters the high-value transportation market) is different from the value of the energy embodied in gas.

There is no global gas price, and the difference between oil and gas energy prices is greater in the US than in continental Europe or Japan. A ratio of 1.3 oil to 1 gas has been typical of US prices over a long period (low US gas prices have widened the margin recently).⁶⁵ This ratio is used in Table 6 as a general indicator of the discount which should be applied to the gas component in an economic aggregation of oil and gas reserves. On a thermal equivalence basis, the fall in private-sector oil reserves since 2000 is far more significant than the growth in private-sector gas reserves, giving an overall fall of 11% in private-sector combined oil and gas reserves. Price adjustment increases this to a 13% fall. Individual companies may have widely different results from the aggregate. For the state sector, the increase in oil reserves outweighs the increase in gas reserves, giving an increase of around a third in oil equivalents by volume and value, as shown in Table 6.

Table 6: Different oil equivalences

	Gas billion cu.ft		Price-adjusted OE		Thermal TOE	
	Private gas	State gas	Private PAOE	State PAOE	Private TOE	State TOE
2000	277	3330	136	1346	148	1492
2010	326	4060	121	1793	136	1971

Source: Adapted from *Petroleum Intelligence Weekly* data.

Strategy and technology

Everywhere technology is critical to adding to oil and gas reserves in the future.

As noted, state companies control 86% of current oil reserves. About 50% of world reserves are open to private-sector companies as partners or contractors to state companies, but one key will not open every door, since state companies' interests are defined by their countries' particular geology and

65 Statement of Howard Gruenspecht, Acting Administrator, US Energy Information Agency, Department of Energy, before the Committee on Energy and Natural Resources, United States Senate, 29 March 2012.

policies. Although a common element among national oil companies is to achieve a clear division of responsibilities between the government owners and the management of the company,⁶⁶ there are broad generic differences, with three rough categories:

- Major companies such as Saudi Aramco, and smaller companies such as Statoil, have clearly defined technical challenges, as well as the scale and technical base to address many of them internally and to assess well the potential of external innovations. Their governments have clear depletion policies.
- Some other national oil companies are limited by budgetary considerations (governments take the money and starve the companies), and political difficulties prevent long-term problems from being addressed.
- Newly established state companies in countries without great technical resources may find the participation of international oil companies the only practical gateway to advanced technology.

Strategic objectives and capabilities vary also in the private sector: here companies are free to explore or add to reserves in a variety of countries, but access to technology and finance is critical to getting opportunities. Some small private-sector companies are exploration-oriented with the objective of farming out or selling out successful discoveries. For them new technology may have high rewards and give them an advantage over larger but more cautious companies. Their situation is different from companies that buy up depleted oilfields from major companies, where the key technical questions relate to reservoir management and improving recovery techniques.

Major private-sector international companies need to find mechanisms to match the potential – and therefore technology needs – of particular country and company situations with the best that is available in global science and technology. In many cases this may involve partnerships with state companies.

66 Victor et al., *Oil and Governance* (see note 28).

6 Finding the Right Partners for National Oil Companies

Valérie Marcel

Key points on partnerships for NOCs

- The competitive landscape for oil companies has changed: the oil majors are surrounded by many new types of companies, both in the areas opened by new technology and in the traditional areas where there are opportunities in partnership with state companies.
- Technology is the key to both sets of opportunities. State companies are looking for partners who bring technology (including the knowledge of large projects and safe operations) specific to their needs. State companies' needs differ and private-sector companies, like service companies, need to match their offers to those differences.
- State companies also expect private-sector companies to contribute to the national development objectives to which the state companies are committed. This involves local sourcing, development of skills and supporting long-term diversification in the economy. Agreement on what is expected, and how its delivery is monitored, are critical to a sustained relationship.
- Partnerships or joint ventures with foreign companies depend on terms set by the state company's government, and their execution by the said company. These will differ from country to country. International foreign companies can no longer impose their own norms on these arrangements.

In mature petroleum provinces, NOCs are operating with higher competency levels. They are increasingly sophisticated customers of oil-service providers and partners with foreign oil companies. Moreover, the publics in both mature and emerging petroleum provinces often expect national participation in the development of their resources. They also expect the development of hydrocarbons to generate greater national development impacts. This bolsters the dominant position of NOCs, which have historically been entrusted with national development. To penetrate these markets, foreign oil companies need to demonstrate that they can offer what producers need, whether technology, human resource development, cost control, capital or refineries. The difficulty for the legacy players – from the old ‘Seven Sisters’⁶⁷ – lies in the widening scope of development objectives that producers want met by foreign oil companies and the narrowing patches of land open to straightforward production-sharing agreements.

The legacy players are no longer the only act in town. This is underscored by the increased activity of NOCs outside their own national boundaries, leading to a greater blurring between international private oil companies and these ‘international’ national oil companies (INOCs). Some of the latter are part-privatized, others fully state-owned, some state-backed and others operating like private companies.

The private companies have long been differentiated by scale and this continues to be true. *Supermajors* are fully integrated, global players that are so big they only mobilize for large-scale projects. *Majors* are fully integrated as well, but often willing to invest in smaller projects. *Midcaps and independents* are non-integrated companies with relatively low refining capacity that develop, supply and produce oil and natural gas.

⁶⁷ Anglo-Persian Oil Company (now BP); Gulf Oil, Standard Oil of California (SoCal) and Texaco (now combined in Chevron); Royal Dutch Shell; and Standard Oil of New Jersey (Esso) and Standard Oil Company of New York (Socony) (now combined in ExxonMobil). At their peak in the 1960s these companies controlled over 80% of the world's oil reserves.

The smaller independents are often the most versatile players. They come in different sizes with different characteristics and can go after opportunities which big companies are too big or too selective to reach for. One category, the *Gleaners*, will acquire depleted fields from large companies and try to squeeze out some extra production with lower cost. A different group of frontier exploration companies looks for exploration licences in areas where the probability of large discoveries seems low or the fiscal and regulatory regime is uncertain owing to a lack of previous oil industry development. These invest just enough to reduce uncertainty for larger players. But they are not equipped to take on major geological or capital risk.

The newer breed of oil industry player is the *Technology Independent*. These relatively small independent companies develop technological expertise in selective spheres – as seen, for instance, in their recent development of shale gas in the United States.

Oil-service companies are changing too. For a long time they were simply the purveyors of technology services to oil operators. Operators, whether national or private, managed the projects and chose the technology. Increasingly the large service companies have taken on project management responsibilities. Some have also begun to offer contracts whereby they take on capital risks against performance-based remuneration, as do oil companies.

Here we will review the landscape of the oil industry and the prospects for partnerships between national oil companies and foreign oil companies. Key is that these various players are suited for different types of petroleum activities. Their size, technological capabilities, access to finance and cost of capital, for example, give them different advantages.

The following section shows that the pressure of stimulating national economic development will lead some national producers to leverage access to the upstream to attract foreign direct investment in other sectors. The section on ‘Meeting geological challenges’ discusses frontier opportunities and assesses which type of company is prepared for these. The section on ‘Matching competencies and needs’ reviews the needs of producers and suggests appropriate business partners, whether independent, oil major, international NOC or service company.

Meeting national development needs

A new paradigm of cooperation

In April 2011, Saudi Aramco’s CEO, Khalid al-Falih, clearly articulated the growing interest of producing governments and their societies in investments that aim to do more than extract resources. He pointed to the need for activities that promote local economic development and job creation: ‘Striking a balance between natural resources, food, water, energy, economic growth and the environment.’⁶⁸ He highlighted the ‘emergence of a third-generation of social expectations’, which required a new paradigm of cooperation to address the corresponding challenge. Implied was the suggestion that IOCs and oil service companies (and even Engineering, Procurement and Construction contractors) should accept a share of the responsibility that the NOCs carry for promoting the socio-economic development of the countries in which they operate. He cited human resource development, cross-training and joint research projects as potential areas of NOC–IOC partnership. He did not put on the table the idea of leveraging access to upstream assets against economic development programmes, but other producers will be more open to the idea, looking for upstream partnerships that will provide jobs and spur economic opportunities nationally by developing ancillary industries and providing training to nationals.

Attracting investment to ancillary industries

The rapid rise in domestic energy demand in Saudi Arabia (8% p.a.) and elsewhere in the Middle East (where prices are subsidized) also creates new investment needs in producing countries. While the removal of subsidies and energy conservation are clearly the most needed policies to change the course

of domestic consumption patterns in the Middle East,⁶⁹ these countries will also seek to diversify their energy mix, turning to nuclear and solar energy, and to develop unconventional gas (shale, tight gas) to meet domestic needs.

There is clearly a widening remit for investors. Classic corporate social responsibility (CSR) programmes saw investors contribute to national welfare through relatively modest and autonomously run schemes that did not challenge state authority and were not substitutes for the state, but that aimed to provide sufficient benefit to local populations to boost the investors' reputation nationally and increase the lifespan of their activities in the country. Host countries increasingly demand more: more control, more investment, more benefit. Oil companies have been under pressure for some time to hire locally and train nationals, but they will increasingly be asked to create national supply chains, invest in infrastructure, provide cheap loans, and support or even jumpstart the creation of new domestic industries. Brazil and Norway have already adopted stringent local content requirements and an increasing number of countries are in the process of doing so. The producers' growing concern for improving local content and benefits has created a market for private-sector consultancies that help oil companies achieve better results in this area.

Many producers would like to entice oil companies to build new refineries or invest in other downstream and midstream infrastructure. Refinery projects provide a secure outlet for large exporters. They are often customized for the less attractive (heavy or sour) crudes that would not always find a buyer. These refineries offer the exporters the option of discounting the price of their crude domestically, without undercutting global crude markets. These projects are also more attractive for the IOCs if they offer discounted crude feedstock for refineries and distillates feedstock for petrochemicals. For small producers, refineries offer greater energy security. They produce gasoline for local markets at prices that are more favourable than fuel imports.

Only very large companies can leverage the necessary capital and project management experience to engage in joint ventures for a refinery or an integrated petrochemical project. But are the majors really interested? They are investing in downstream and chemicals where demand is growing fast: largely in China and Saudi Arabia. For example, CNPC, Shell and QP have invested in the China Integrated Refining and Petrochemical Project; Total and Saudi Aramco formed SATORP to develop a greenfield refining and petrochemical project in KSA; Dow and Aramco formed the Dow-Aramco Integrated Petrochemical Complex in Jubail; Saudi Polymers Corp joined with Chevron Phillips Chemicals and an SIIG subsidiary in Saudi Arabia. These large companies are also engaged in Singapore (ExxonMobil Chemicals and Shell Chemicals in two separate petrochemical projects) and Algeria (Total and Sonatrach in the Arzew Petrochemical Complex).

In sub-Saharan Africa, refining capacity is not meeting demand. But the majors have largely divested from the downstream in Africa. The Chinese state-owned company CNPC is among the few bucking the trend by investing in refineries in Chad and Niger. The African Refiners Association (ARA) is challenging investors to develop existing refineries in Africa to meet new cleaner product specifications and develop the vital distribution infrastructure needed to supply the fast-growing African product demand.⁷⁰ CITAC Africa Ltd., a consultancy retained by the ARA, suggests demand for refined products in Africa will see an annual growth of 3.4% by 2020. A possible game-changer is the scale of discoveries made on the east coast of Africa, in Uganda and Kenya, which led the independent Tullow Oil, China's CNOOC Ltd. and French major Total to consider investing \$5 billion in building pipelines that would form a regional oil export hub to transport this crude to world markets. These producers will seek to secure investments in refining as part of these deals.

Attracting investment in infrastructure

In Iraq, the majors and the INOCs have gained access to vast reserves, though not with the industry's preferred production-sharing terms. In Iraq's 2009 licensing round, bidders were requested to offer soft loans (for a total of \$2.6 billion in 2009), which would be paid in oil and used to finance reconstruction

69 Glada Lahn and Paul Stevens, *Burning Oil to Keep Cool; The Hidden Energy Crisis in Saudi Arabia*, Chatham House Programme Report, December 2011.

70 CITAC news release, 7 March 2012, http://citac.mbendi.com/a_sndmsg/news_view.asp?l=123267&PG=165.

projects. But the companies were not required to take on midstream infrastructure commitments. Today, many oil companies investing in Iraq face difficulties in meeting their upstream production targets because of a failure of infrastructure to keep up with the pace of their activities. In the light of the Iraqi government's inability to complete the needed infrastructure projects, it might have been preferable to structure upstream projects to include infrastructure components. That said, companies need financial incentives to deliver infrastructure projects, and government authorities must manage the projects competently.

The agreement with Shell for the development of a gas network, and ExxonMobil's water desalination project to support oil recovery in mature fields were both exceptions in which infrastructure was tied to the upstream – though these projects have failed to get off the ground. Indeed, the Iraqi government took away ExxonMobil's \$10 billion water contract in 2012, purportedly because of disagreement over costs and the company's failure to coordinate the delivery of the project. Iraq instead sought bids from international consultancy firms to manage the project.

Shell's agreement to capture flared gas and bring it to domestic and international markets was also mired by lack of clarity on terms and the opaque negotiations involved. It further emerged from leaked diplomatic cables that the Iraqi authorities were not equipped with the necessary economic knowledge to negotiate the terms of the contract with Shell.⁷¹ In Iraq's successive bidding rounds, opportunities were missed to coordinate upstream, midstream and downstream development. Faced with bottlenecks in transport and export facilities, companies' upstream plans are held back, and they may yet be forced to take on midstream and utilities projects.

Chinese NOCs and cross-investments

INOCs may be better designed to make these investments in national development profitable – they do this kind of thing at home. Such multi-layered objectives have been most notable in Chinese investments in the energy sector. Their attempts to lock in oil imports to China have been well documented; however, there is more to the international expansion of Chinese NOCs. As Yale University's BinBin Jiang argued, even the most 'state agent' of the NOCs, CNPC, is driven overseas by the prospect of earning higher profits and enjoying greater autonomy from the state in its operations, and not so much by state diktats.⁷² Chinese NOCs' international investments also seek to foster economic interdependence between the host country and China, which will lead to increased trade and investment opportunities for other Chinese businesses.

To the extent that cross-investment materializes so that the host country's industry can benefit, this strategy will satisfy the goal of producing countries, as identified by Saudi Aramco's CEO, of leveraging the upstream sector to promote local economic development. In this respect, the track record to date of these cross-investments is not necessarily positive. Some commentators have argued that Chinese company investments in Africa were accompanied by flooding of local markets with cheap manufactured goods from China.⁷³ As a closer look at the cases of Nigeria and Angola will demonstrate, investments must be carefully managed by both parties to be mutually beneficial.

From 2004, Asian companies gained a foothold in Nigeria's upstream oil sector in return for investments in downstream and infrastructure projects. But several blocks awarded to Asian companies were later cancelled. With no infrastructure projects getting off the ground, the scheme proved a failure. This was largely because of the Nigerian government's inability to manage the scheme, poor understanding on the part of the Asian companies of the political situation in Nigeria (in that political elites would attempt to capture benefits) and the lack of formal mechanisms to ensure the deals were enforced.⁷⁴ A parallel can be drawn here with the difficulties faced by the majors in getting infrastructure projects off the ground in Iraq, which were attributable in part to the poor management of the agreements by political authorities and to difficulties in reaching an agreement with companies over costs.

71 Ben Lando and Ben Van Heuvelen, 'The secret history of the Shell gas deal', *Iraq Oil Report*, 23 September 2011; available at <http://www.iraqoilreport.com/energy/natural-gas/the-secret-history-of-the-shell-gas-deal-6221/>.

72 In Victor et al., *Oil and Governance*, p. 381.

73 Owusu Carmody, (2007), 'Competing Hegemons? Chinese Versus American Geo-Economic Strategies in Africa', *Political Geography* 26.

74 Alex Vines, Lillian Wong, Markus Weimer and Indira Campos (2009), *Thirst for African Oil; Asian National Oil Companies in Nigeria and Angola*, Chatham House Report.

In contrast, the Chinese companies were successful in Angola, where China facilitated soft oil-backed loans for infrastructure development and Sinopec obtained equity stakes in several blocks. The relationship was carefully managed for the mutual benefit of Angola and China, with careful interlinking of diplomacy and business.⁷⁵ Angola always remained in the driving seat, negotiating the terms of deals from a strong negotiating position.⁷⁶

State companies with deep pockets

Chinese companies in Angola were willing to provide oil-backed loans to help with post-war reconstruction at a time when Western donors were reluctant to offer finance.⁷⁷ Similar deals were struck in Venezuela, Petrobras, Ecuador, Russia, Argentina and Kazakhstan, which secured Chinese capital against oil shipments. As in Angola, the deals were often backed up by trade opportunities and China is now Latin America's third largest foreign investor (ECLAC).

While analysts have for some time suspected the Chinese companies of overpaying for assets,⁷⁸ others found no evidence of systematic or intentional overpayment.⁷⁹ Their cost of capital is undoubtedly lower than that of the majors, and they are willing to commit more of it in order to draw down their large foreign currency reserves. The availability and cost of capital for such NOCs allow them to offer loans for infrastructure development, and this poses a clear challenge to IOCs.

The experience of Asian companies in Africa and Latin America shows that, while they have successfully gained access to reserves in some instances by wielding promises of credits and investment for development, they have also acquired equity participation by farming in to existing projects and acquiring companies with stakes in assets, as do private IOCs. The result is not, as some Western capitals had feared, a checkerboard dominated by Asian NOCs. The oil majors continue to dominate in both regions. Also, Asian NOCs have not been equally successful. Chinese companies have outpaced Indian companies, which are more risk-averse. Chinese and Indian companies alike have faced some difficulties in dealing with governments that are not managed by a strong central power and where the NOC is not a capable manager of state resources (in contrast to Angola).

Chinese companies, as well as other large NOCs, will increasingly face the reputational and business risk related to investing in countries under unilateral sanctions (e.g. Sudan, Iran) and where political rulers do not manage investments and profits to the benefit of development. Failure to address the problem of capture by elites contributed to the investments falling apart in Nigeria, for instance. In their African investments, Chinese companies have conducted sub-standard labour and environmental operations in the mining sector as a result of weak Chinese and domestic regulations. The Chinese government is increasingly wary of the potential fallout of poorly managed foreign operations, and regulations are changing. In 2007 China's Ex-Im Bank issued guidelines on impact assessments, and China's State Environmental Regulatory Committee and the State Environmental Protection Administration stipulated stricter lending policies.⁸⁰

Meeting geological challenges

The frontier is looming for mature producers

As the large reserves deplete, state companies will turn increasingly to frontier exploration and the development of resources that require technically difficult or innovative technology (shale oil and gas, tight sands, ultra-deep water and Arctic offshore as well as enhanced recovery⁸¹ from depleting fields). A few state companies with sufficient size and technical depth are developing the capacity to handle their

75 Ibid.

76 Ibid.

77 By 2009 China had facilitated at least \$13.4 billion in loans to Angola (Vines et al., 2009).

78 Wood Mackenzie study in 2010.

79 Julie Jiang and Jonathan Sinton, *Overseas Investments by Chinese National Oil Companies*, International Energy Agency, 2011.

80 Barbara Kotschwar, Theodore H. Moran and Julia Muir, 'Chinese Investment in Latin American Resources: The Good, the Bad, and the Ugly', Working Paper 12-3, Peterson Institute for International Economics, February 2012.

81 Using the injection of gas, chemicals or heat.

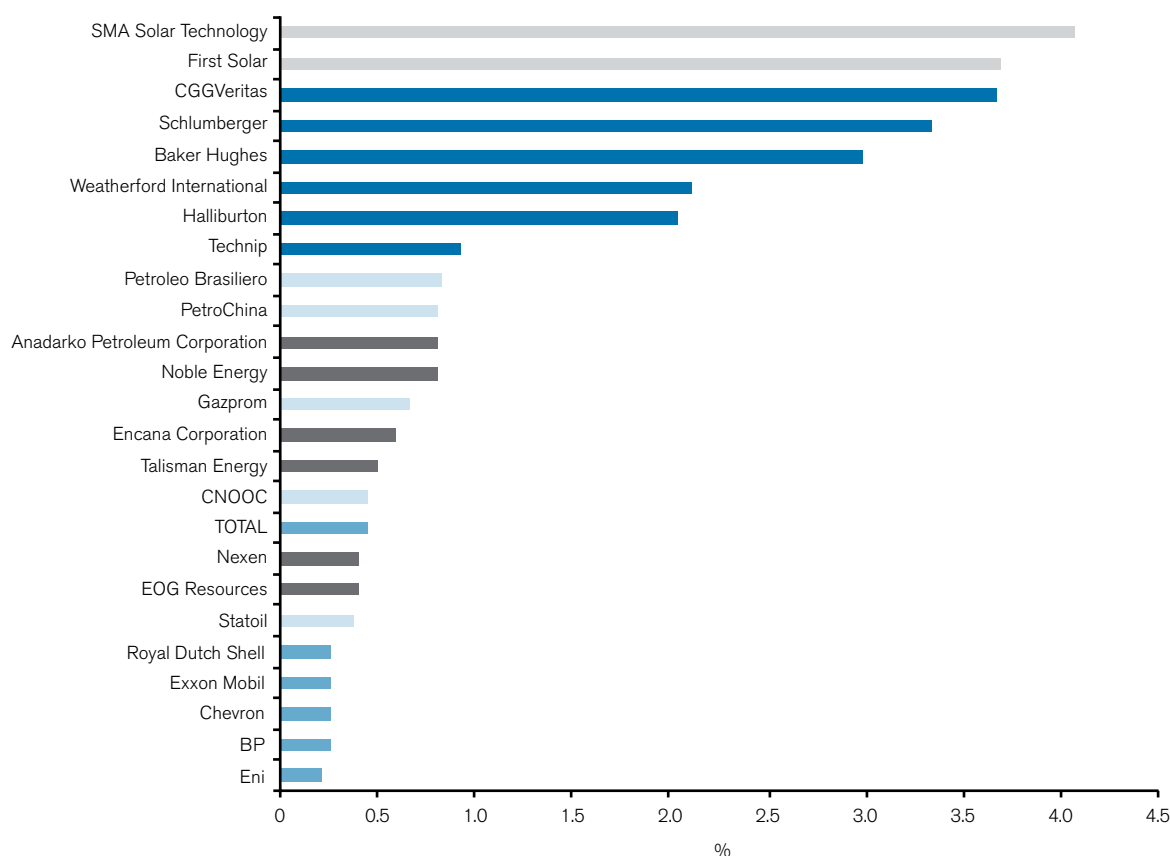
particular challenges. Generally, however, the geological challenges may induce more state companies to become more open to investors.

Host governments may also change their views. New reserves, difficult oil and gas or development choices in the later days of enhanced recovery will involve significantly increased risks. As Nolan and Thurber explained, when making exploration or development decisions for frontier petroleum activities there are only very imperfect analogues available and with uncertainty the risk is greater.⁸² The state's appetite for risk of this order will depend on how much its future revenues will depend on frontier petroleum activities. To handle these, the state will need to require its NOCs to develop risk management and technology skills so they can face the technology and costs management challenge (and continue to invite only service contractors), or it will need to give foreign companies a stake in the reserves. In the latter case, a state would most likely turn to the majors to help manage risk, but the future may offer more competition from INOCs and the new hybrid oil-service risk companies.

Which companies are prepared for the frontier opportunities?

If demand for technology solutions and risk management skills does in fact grow, international oil majors, independents, service companies and INOCs can be expected to prepare by investing appropriately in developing their skills. Conversely, for those countries choosing to go it alone, their NOCs should be strategic in developing in-house technology to address future geological challenges. It is instructive to compare the R&D programmes of various companies in assessing which of them are focused on these issues.

Figure 10: R&D expenditure for various types of companies as a ratio of net sales, 2010



Source: European Commission; Zacks; Research Infosource Inc.

82 Peter A. Nolan and Mark C. Thurber, 'On the State's Choice of Oil Company: Risk Management and the Frontier of the Petroleum Industry', Chapter 4 in Victor et al., *Oil and Governance*.

A common metric for innovation is a company's R&D expenditure, which is essentially how much a company spends to develop new products and services each year. It is exceedingly difficult to obtain detailed data about this spending because such information is usually considered proprietary. Also collecting comparable international data is daunting because of variations across countries in categories and definitions for R&D funding.⁸³ With these imperfect data, Figure 10 shows the high commitment of alternative energy companies (in light grey) and oil-service companies (in dark blue) to their R&D budget as a share of total revenues. It also shows how well some select (and perhaps unusual) national operators (in light blue) compare to the oil majors in terms of technology development. PetroChina stands out as the top spender in absolute terms on R&D in 2010 among all oil and gas companies. While Figure 10 indicates a higher focus on technology among the independents (in dark grey), the data for these companies are from a different data set. Moreover oil-major and NOC revenues usually include trading, refining and petrochemicals, whereas the revenues of service companies or independents do not. The way this influences the comparison is not clear cut: trading adds considerably to total revenues, though R&D spend for chemicals tends to be higher than for other business segments.

Innovators

Innovation is a greater differentiator than R&D expenditure. Companies often need only innovate in one specific technical area. Some independents and small service companies have specialized technology and skills that may slip under the radar of the larger players for some time, active in what looks like a marginal play – for instance, shale gas in the US. Mitchell Energy was a front-runner in the development of shale gas technology and while George Mitchell poured \$7–8 million of his own money into technology development, the company was also supported by the US Department of Energy, which subsidized the first horizontal well it drilled in the Barnett Shale in Texas. Independents are nimble thanks to their characteristically decentralized corporate structure, and it was this characteristic that allowed quick, in-the-field decision-making in the shale gas sector.

Some NOCs are also true innovators. Petrobras, for instance, is developing a unique expertise in pre-salt ultra-deep reservoirs. This technology can help access new reserves abroad and serve to diversify the company's asset base. Petrobras, like Saudi Aramco, Petronas and the Chinese NOCs, conducts R&D in-house, and all these companies also benefit from the wider national research capabilities located in specialized universities and research centres (to which they contribute financially). In Saudi Arabia, the King Fahd University of Petroleum and Minerals and King Abdullah University of Science and Technology (KAUST) are sources of technology innovation and train bright people in the relevant skills.

Developing human capital is a key factor in enhancing technological capacity for both IOCs and NOCs. Nurturing the appropriate corporate culture is paramount and can be a particular challenge for NOCs (though it is not an issue only for state-owned companies). To deal with the challenges of new geology or new types of partners, for instance, companies must encourage employees to have a flexible attitude and a willingness to try new things.

Knowing what technology to invest in

Studies by Booz & Company on innovation find that strategic alignment and a culture that supports innovation are key to financial performance. Investing and boosting innovation in the areas identified as strategically important to a company bring about better results. This alignment appears strong in some INOCs, which have identified technology needs on the basis of the reserves they already hold. In contrast, IOCs (and INOCs with dwindling reserves at home) must first identify which reserves they will focus on for future growth. The uncertainty of the future resource base can make their technology development look like a gamble.

Recent NOC investments and acquisitions in unconventional oil and gas serve to illustrate the difference in focus. China and Saudi Arabia have identified potentially significant shale resources at home and their NOCs seek means of acquiring the technology and the know-how to develop them. The oilfield service company

83 Kelly Sims Gallagher, John P. Holdren, and Ambuj D. Sagar (2006), 'Energy-Technology Innovation', *Annual Review of Environmental Resources* 31.

Baker Hughes opened a research centre with Saudi Aramco in Dhahran, focused on understanding and developing unconventional resources, in particular shale gas. Alongside CNOOC and Sinopec, Saudi Aramco expressed interest in acquiring Frac Tech International in December 2011. In 2011 Saudi Aramco began exploring for tight and shale gas in the northwest of the kingdom, without the help of foreign oil companies.

Alliances that trade frontier skills for access to reserves

China took a different approach to secure shale technology, relying on partnerships and more aggressive acquisitions. Chinese companies invested in shale projects in the US, where the technology for developing shale gas was pioneered. PetroChina cooperated with Shell on several projects and bought a 20% stake in Shell's Canadian shale gas project. In 2012 CNPC signed a production-sharing contract with Shell to explore and produce shale gas in China, and BP, Total and Chevron have also collaborated with Chinese companies to search for shale gas in China.

These partnerships are not necessarily win-win. While securing access to new shale resources in China is attractive, the pairing of a qualified national operator with an oil major risks cannibalizing the latter's future markets elsewhere. Indeed, the transfer of skills and technology to Chinese rivals will inevitably shorten the lifespan of the majors' technological advantage.

ExxonMobil and Russian national oil company Rosneft have forged an even more ambitious partnership in 2012, with cross-investments giving the supermajor access to Russia's offshore exploration projects in the Kara Sea in the north of the country and in the Black Sea in return for a stake for the NOC in some of ExxonMobil's US and Canadian assets. Rosneft said that its participation in the project might lead to the development of technologies for unconventional reservoirs in Russia.⁸⁴

On a strategic level, the gains here may again be greater for the NOC than for the private major: Rosneft increases and diversifies its foreign assets, takes a stake in unconventional oil projects and learns skills and technology from one of the industry's leading companies. As Rosneft president Eduard Khudainatov pointed out, he was certain that '15 years of Rosneft and ExxonMobil partnership' would allow the Russian company 'to become one of the global leaders in the oil and gas industry'.⁸⁵

A greater variety of investors at the ready

The oil and gas industry is more competitive than ever. Oil majors face limited opportunities in the large reserve-holding countries as NOCs becoming qualified national operators, able to draw on the expertise of service companies to fill their technology needs, acquiring smaller companies to access technology and skills, and building their skills through joint ventures abroad. As noted earlier, the majors also face competition from INOCs willing to offer soft loans and infrastructure. In the new plays on the margin, the role played by the oil majors is increasingly to farm in once the scale and risk justify the investment. For instance, independents and exploration independents have in recent years taken on the exploration and political risks in new frontiers in Africa and elsewhere, selling part or all of their assets once the find is large enough to justify the majors' commitment of human and financial resources. Similarly, after the technologically oriented independents created a shale gas revolution in the US and invested in oil sands in Canada, large oil majors started taking over many of the assets.

Schlumberger's Andrew Gould noted that while in the past only the majors had large project-management capabilities, capital expenditure trends show that more and more companies are undertaking larger and larger projects, often in remote or complex environments. More than 40 companies are now managing development projects worth more than \$1 billion. NOCs and independents are taking the lion's share of the operator market; indeed these companies are now responsible for over 75% of total upstream capital expenditure (capex).⁸⁶

Investment trends point to the oil majors turning their attention westward, to areas not dominated by national operators. Research by Wood Mackenzie indicates that more than half of the IOCs' long-term

84 *Upstream*, 20 April 2012.

85 *Ibid.*

86 Andrew Gould, 'The Energy Landscape', Text of presentation given at Barclays Capital Commodity Conference, New York, 1 March 2012.

capital investments are going into developing deepwater, shale/tight oil, shale gas and oil sands.⁸⁷ While the majors would presumably prefer to acquire equity in oil and gas assets through traditional licensing and production-sharing agreements in mature basins in the eastern hemisphere, access is largely closed or restricted to service contracts.

This huge shift in investment focus to unconventional reserves in the west may in fact play out to the advantage of the majors in the long term, since the lack of choice forces them to invest in their technological edge, playing to their strengths. These technologically risky and capital-intensive projects will enhance the IOCs' technological expertise in new and unconventional oil and gas exploration and development.

With time, the traditionally state-controlled areas too will face these geological challenges. Geology works against many NOCs, which will need the support of oil majors to face depletion challenges and new types of reserves. As noted in the cases of China and Russia, the IOCs' mastery of the technology and skills needed for the development of ultra-heavy, sour, tight and ultra-deepwater resources opens new markets in the producing countries in the eastern hemisphere. Here production in increasingly mature reservoirs will decline, forcing NOCs to turn to new types of geology with which they are unfamiliar. The most capable NOCs will be able to deal with this challenge without the IOCs or take over from them once they have mastered the geological challenge thanks to partnerships – but many others will not.

The next niche of the oil majors as partners will be in this inevitably temporary phase, when needs arise in the producing countries and the majors offer greater skills than the competitors hot on their trail. The door will close over time, as the technological – as well as cost- and risk-management – skills of the oil majors in today's geological frontier become more commonplace. They can extend their advantage, however, if they keep developing new solutions.

Matching competencies and needs

Different types of host governments will turn to different investors, depending on their needs – whether technology, capital, risk management, large project management, training, infrastructure, national development or political complementarity. Table 7 lays out some complementarities based on the level of national capabilities and the geological context.

Table 7: The choice of investor depends on the level of national capacity and the geological context

Preferred investors in different contexts	NOC characteristics			
	Reserves characteristics	New NOC, low operating skills	Mature NOC	
<i>No R&D</i>			<i>R&D</i>	
Exploration	International NOCs Independents	INOCs Independents	Service companies	
Frontier (e.g., enhanced oil recovery, sour gas, heavy oil, geographically challenging, tight oil and gas)	Majors International NOCs Independents	<i>Acquire:</i> Majors INOCs Independents Risk service companies	<i>Acquire:</i> Independents INOCs Risk service companies Service companies	
Development large reserves	Majors International NOCs Independents	Service companies For contribution to economy, welfare: International NOCs		
Declining reserves, small fields (secondary recovery, low cost)	Gleaners	Service companies		

Large reserve holders with mature NOCs

Large reserve holders with long-established NOCs will only turn to service companies if their NOCs can manage them and are qualified operators. In this type of mature petroleum province, operations are largely run on a business-as-usual model, with development, transport and marketing the greatest activity types. While exploration is not insignificant, it is not likely to be the main focus of an NOC's activities. As such, the NOC must manage some geological risk, specifically through whatever exploration it carries out and through reservoir management during development, as well as other uncertainties related to future market conditions and the financial risk involved in field development.⁸⁸ The greater the competence of the NOC in this context, the better able it will be to manage service providers to apply the appropriate technology when new geological challenges emerge. Oil-service companies can also provide training and joint R&D (and capital can be borrowed by the NOC if necessary when large reserves are known), and such companies have increasingly applied large project-management skills, but they are not the perfect suitor for a government in search of risk management for frontier reserves.

Should the government need infrastructure and national development, many international NOCs are designed to offer this along with upstream investments. Broad investment packages could also conceivably come from countries such as Japan, which could exploit their wider industrial interests (construction, steelmaking, electronics, and chemicals) in a cluster around their private oil companies.

Large reserve holders with new NOCs

In the case of large reserve holders with young NOCs (see Table 7), the NOCs will not be able to manage the risk involved in the exploration and appraisal of a new petroleum province. Inviting foreign investors to take a working interest in the project reduces the capital exposed to a potential loss and brings in expertise to handle operations. Large reserve holders are most likely to turn to the majors and INOCs first, as these are equipped to manage high capital and geological risks. Independents which were involved in the exploration and discovery of reserves may stay on for development (usually farming out a working interest to a larger player), but they are at a disadvantage in terms of late entry because of the scale of investments and the associated capital risk. Countries with medium to large reserves, such as Mozambique, could do well with a small IOC or independent.

Producers at the exploration stage, with the size of deposits still uncertain, are attracting international NOCs, exploration-focused independents (which will look to sell part or all of their assets once a discovery is made, or even before), and independents with technological competence. Majors have become exploration-averse when the prospectivity is uncertain, whereas independents play on the margins and take exploration risk. For instance, in 2011 the independent Tullow increased its reserves and resource by 959% without acquisitions,⁸⁹ while the majors struggle to maintain at least 100% reserves replacement. The big majors will not mobilize their personnel and capital for a smaller-scale activity. Now that the independents have established Africa's east coast (the Kenya and Ethiopia Rifts, Mozambique offshore) as a hot play, the scale is more attractive to the majors, which have more resources and ability to bring Mozambican gas to market.

In countries with smaller, declining reserves IOCs have sold their assets to small independents (the Gleaners), with low costs, which can profitably extract oil with established technology. In countries with competent, mature NOCs, this secondary recovery can be handled by the NOC with the support of service companies.

NOC acquisitions to access technology

As discussed earlier, some international NOCs and national operators are looking to take stakes in assets or acquire small companies that would help them learn how to develop their unconventional reserves. These joint ventures between NOCs and Technology Independents may offer a good alignment of

88 Nolan, Thurber, in Victor et al. *Oil and Governance*, p. 127.

89 Tullow Oil, <http://www.tullowoil.com/index.asp?pageid=113>.

interests. The latter have developed innovative drilling and extraction techniques, but do not have large capitalization and need capital injections in order to progress. GAIL (India) Ltd, for example, formed a joint venture with US independent Carrizo Oil & Gas that gives the Indian NOC access to acreage and a 20% interest in producing wells. The Chinese companies in particular are able to meet these capital needs. In order to avoid a protectionist backlash in the US, the deals are structured so that the Chinese companies do not themselves take a stake of the American companies. As the CEO of Chesapeake, Aubrey McClendon, explained, ‘They didn’t come over here and try to buy Chesapeake. ... They came over here to buy a minority, non-operating interest in an asset and not take the oil and gas home.’⁹⁰ That said, they may take the technology home.

Small independents operating outside the US can be more easily acquired by INOCs without provoking political sensitivities. In early 2012, the Dublin- and London-based Cove Energy threw up a ‘For Sale’ sign for the whole company. Thanks to its stake in the Rovuma Area 1 offshore Mozambique, Cove attracted interest from the Indian NOCs ONGC and Gail India, Thailand’s PTT-EP and Shell. That the relatively small NOC player PTT bid against Shell was revealing of the growing confidence of NOCs. PTT eventually won the bid. Similarly, in 2010, state-owned Korea National Oil Corp. acquired the UK-listed Dana Petroleum in an unprecedented hostile takeover by an Asian NOC. In this deal, the independent gains diplomatic support from Seoul when approaching Middle East and African governments for licences and the Korean parent increases its production volumes and diversifies its assets.⁹¹ In 2011, CNOOC acquired Canadian oil sands producer OPTI Canada, which has a 35% working interest in three Athabasca oil sands properties. In 2012, CNOOC moved to acquire Nexen, one of Canada’s largest oil and gas companies. The \$15.1bn bid, China’s biggest foreign takeover attempt yet, is likely to receive the support of Nexen’s shareholders and management, but Prime Minister Stephen Harper has suggested that federal approval will be conditional on reciprocal treatment of Canadian companies in China.

NOC–service company partnerships

Oil and gas service companies also have a key role to play. They have long denied wanting to encroach on the territory of IOCs. However, there are signs to the contrary. Large oil-service companies have been developing integrated project management services, once the domain of IOCs. They can discreetly carry out projects in countries where foreign investment is politically sensitive – without booking reserves or production.

Until now an important difference allowed these entities to be easily distinguished: IOCs took on risk, while service companies were simply paid a fee. Interestingly, the new joint venture between Schlumberger and Petrofac will have a service company offering ‘risked service’ contracts.⁹² Petrofac has been a proponent of these contracts, where service companies take up-front capital risks in exchange for a financial upside linked to project performance, but do not book reserves or production. Petrofac estimates some 2,400 small and medium-sized fields would be suitable targets for risked-service contracts. These fields are too marginal for the oil majors and beyond the financial or technical capabilities of the producers. International NOCs are also partnering with service companies to access technology for unconventional resources. The Malaysian NOC Petronas Carigali, for instance, has a partnership agreement with Halliburton to evaluate and develop global shale resources. The two companies will also set up a shale R&D and training centre in Kuala Lumpur.

In any case, opportunities will still be segmented, as the majors will be best suited for large projects, and the risk-service companies will pick up smaller-scale projects. Companies will benefit too from establishing their technical expertise in certain types of reservoirs, as producers will have specific needs associated with their special geology.

However, having the right competencies to meet the technological or development needs of the producers does not guarantee a successful partnership. The terms have to be mutually acceptable. The urgency of the

90 *Wall Street Journal*, 6 March 2012.

91 *PfW*, No. 4, 30 January 2012.

92 *PfW*, 16 January 2012.

government need for these competencies and the domestic political context will determine how attractive the terms are – i.e., whether service contracts, high returns or reserve booking.

Investors must also pass the political test. Constitutional obstacles to foreign investment or nationalistic political sentiment towards the oil sector may prevent production-sharing contracts, in which oil companies book oil reserves. In such cases, service companies and INOCs are better suitors. In Iraq, where nationalistic sentiment about the oil sector was high, the government offered service contracts and clearly favoured consortia with NOCs as prominent partners. In the first round, one out of three licences were awarded to a consortium with an NOC; in the second round NOCs were involved in every licence; and the 2010 round for gas again figured a cast of NOCs.⁹³

Some IOCs are not satisfied with these terms – as ExxonMobil signalled when it risked losing its large contract with the federal government for West Qurna I by signing production-sharing contracts for smaller fields in the Kurdish region. For the consuming country's international NOCs, and specifically for Chinese companies, international acquisitions primarily aim for equity stakes, but they take on service contracts more willingly than IOCs.

The oil price is also an important factor in determining the types of contracts and terms on offer. In a high oil price context, producing countries and their NOCs can more easily finance their operations without foreign investors. Assets are also worth more, and this is reflected in the greater bargaining power of producers. Broadly speaking, terms are likely to be least attractive in countries where nationalism is strong, where the state or NOC can deliver the welfare and development services the government requires, where the NOC is prepared to handle commercial and technical risks, and when the oil prices are high. Foreign investors are likely to be more welcome in countries where the approach to the oil sector is businesslike rather than political, where development needs are urgent, where the NOC cannot handle all the risks, and when oil prices are low.

Implications for both sides

A sense of urgency about developing reserves can spur changes in contract terms, though a key argument made here is that international oil majors will need to adapt and match their offering to the needs of different types of producers – and indeed to specific producers. The bargaining power of the producer changes with increased certainty about the resources, but also with higher oil prices and a greater number of bidders (and types of bidders). It also increases as the investor sinks more costs into a project. Greater bargaining power on the producer side may require the majors to be more flexible on contract terms in countries with proved reserves, political obstacles to booking reserves or a competent national operator.

Across the board, the oil majors must adapt to the competition and differentiate themselves – either through technological achievements or experience that allow them to stand out as best in class for certain types of frontier reserves, or through their ability to develop and bring to market recently discovered reserves. But technical and business skills are not all that is needed: human resources and development will be important selection criteria for many producers. To compete with international NOCs and service companies, the majors will need to integrate the delivery of such targets into their business plan. Gone are the days of public relations-oriented CSR programmes that stand far away from the company's strategy and operations teams; oil companies will need to find ways to devise more ambitious training and local content strategies and to make them beneficial and intrinsic parts of their business.

The implications for oil companies seeking access to new acreage boil down to finding the right match for their interests and capabilities among a growing diversity of producing countries. Successful partnerships need a fit between both sides with regard to their respective priorities and capabilities. They intersect on issues such as technical competence (in some cases this amounts to project management and operations, in others risk management and innovation), financial objectives (from the producer's

93 Valérie Marcel (2012), 'Memo on Gulf Oil Producers' Investment Flows', Workshop on Oil and Political Relationships, Council on Foreign Relations, 19–20 January 2012.

perspective, this may mean securing a commitment to finance exploration, while the investor will seek to be incentivized to deploy technology) and national development (utilizing and developing local capabilities, investing in long-term diversification). The national oil company's skills and needs will necessarily evolve, which may pose a challenge to a long-term partnership.

Agreeing on whether national development investments are peripheral or central components of the partnership is paramount. Critical steps for obtaining mutual benefit from the broader-scope partnerships include setting targets for elements such as technology transfer and local content, clarifying the costs of these commitments, and monitoring progress carefully. In that broad development partnership, the oil partner is orchestrating a range of services, and this requires the NOC to coordinate all relevant government bodies (or ensure a ministry is tasked to do so). On both the technology and national developments fronts, it is also essential to clarify the mechanics of performance rewards: what are the priorities, how is performance judged and recompensed? Alignment on expectations helps to clarify the terms of the partnership as it matures. It is also good to include provisions for breaking up, when competences and needs no longer match up.

7 Financing the Future

Beth Mitchell

Key points for investors

- Future demand for oil and gas is uncertain, reducing the gearing of oil and gas companies to economic growth; companies will have to generate their own growth.
- National oil companies control access to most current reserves. IOCs may be able to gain some access to these by improving their partnership offer.
- Most accessible projects are difficult or unconventional; improvements in every aspect of process excellence, from structuring deals through technological superiority to project management and safety, will be necessary to underpin success.
- Companies with great management do survive and prosper despite an industry changing out of all recognition. They are not necessarily those that made the best long-term predictions, but those that escaped the shackles of past beliefs about their industry and adapted, often radically, to the changes.

This chapter examines how external investors regard the oil and gas industry and whether the flow of funds from investors to projects can be improved. There may be significant differences between these external views and the beliefs of industry participants. These may arise from differences of context: within an oil company, oil- and gas-related investments form the opportunity set, whereas external investors encompass a much broader range of companies. Differences may arise from timing within the economic cycle: cyclical companies would be relatively less attractive in a recession. Sometimes investors are much more optimistic or pessimistic than industry participants for a period. They are not always more correct than industry participants but it does happen, particularly at times of great change, when extrapolating from past experience is misleading. In many industries that have changed enormously over the last 25 years managements were in denial about changes for a surprisingly long time, and responded quite aggressively to investors' questions. The truth will out, however.

The focus is on the IOCs, in which investors can buy shares directly, though it is impossible not to contrast their financing strengths and challenges with those of the NOCs.

Old questions, new answers

Although the question of resource allocation has often been asked by the oil industry, it must be revisited regularly as circumstances change. The challenge for participants is to avoid being biased by the human inclination to extrapolate the current (whether assumptions, market structure or consumer behaviour) into the future. It really can be different this time, with significant structural change causing previously very stable businesses to disappear; witness the disruptive effect that the internet has had on the business models of the music industry and print media (destructively) and on retailing (much more mixed, but impossible to ignore). Interestingly, the successful surviving companies were not those that were best at predicting the long-range future, but those that understood and responded to the current and near-term changes and were flexible and brave enough to keep adapting.

Clearly this is particularly challenging for large-scale, capital-intensive industries where the time lag between decision and change is long, as are asset lives. Taking the chemical industry as an example, the

impact of new entrants and the need for radical choices shows the clear division between winners and losers. Conversely the paper industry demonstrates the depressing result of persistent overcapacity and returns below the cost of capital over a shockingly long period.

For the oil and gas industry the challenge is complicated by the wide variety of players with very different agendas, some non-rational in purely economic terms. There have been real and significant changes.

The investment proposition: better or worse?

The quoted IOCs are not highly rated: is this because the shares are cheap, or because the market believes that the companies' prospects are worsening? And if the latter, are the markets right?

What characteristics do investors value? Growth and positive change.

Broadly, the characteristics investors look for are *growth and positive change*: growth including market growth, market share growth, pricing power or cost control (or both), giving potentially improving margins, product differentiation, innovative capacity (indicated by patents and intellectual property) and lack of political risk; and change including restructuring and market consolidation. In the case of commodity companies, much of their appeal lies in their profits being geared to economic growth through volume and price.

The mid-2012 ratings of IOC shares indicate that investors do not believe that the companies in which they can invest, as currently constituted, offer the prospect of an attractive rate of growth or of positive change.

There are exceptions within the sector, for example BG and Tullow, where the growth trajectory is clearer and the markets have given their shares higher ratings. Their challenge will be to continue to grow and to manage investors' expectations appropriately.

An unsupportive overall economic environment

Investors worry that the oil and gas sector will see less growth, and in different regions.

Investors see the next period as being one of lower overall growth, with a very marked shift away from OECD towards non-OECD countries. The latter have different demand patterns and market structures; new capacity (downstream) can not only be built in the right location, but be more advanced technologically in terms both of efficiency and of being configured to meet the impending climate change requirements. IOCs risk being left with stranded assets, and even where companies succeed in exiting their less advantaged OECD plant they may be denied investment access to the growth markets such as Asia where a domestic NOC has a more dominant position. There has been a long list of companies trying to sell downstream assets in Europe, for example, but even where a buyer is found, the issue of overcapacity (estimated to be 12–16% in Europe⁹⁴) is not solved by a change of ownership. As in the paper industry, even the better assets are disadvantaged by this.

Where there is growth, investors will ascribe value.

In an era of low growth, investors will ascribe high value to companies that can demonstrate growth, but are less likely to be attracted to companies perceived to be very dependent on economic growth to drive volumes and/or prices.

Investors believe that the market share of oil is increasingly under pressure.

As has been described in Chapter 2, the market share of oil is under considerable and growing pressure. This will come both from competing fuels, driven by the impetus to reduce carbon emissions, and from

94 Bank of America Merrill Lynch, 'European Refiners: Advantaged Assets Have Quality Yield Potential This Cycle', 9 November 2011.

energy efficiency becoming embedded throughout the economy: in transport, in appliances, in industrial production and within the home. However chaotic the formal process of climate change limitation is at government level, manufacturers have clearly decided to follow this trend, and with incomes squeezed and energy costs high, efficiency is a desirable characteristic to embed in pretty much everything.

Climate change measures: a huge, unpredictable threat

Not if, but when: investors dislike political/regulatory risk.

The overarching pressure on the industry from governments' regulatory responses to the threat of climate change is the largest and most unmanageable risk for investors. Notwithstanding short-term reluctance of governments to impose any measures that might constrain economic growth, at some point the cost of imposing such measures will be outweighed by the potential costs of not doing so sooner rather than later. It is analogous to the impact of the internet on everything, in having direct and indirect effects that are both unpredictable and likely to be severe. The degree of impact and the political (rather than just economic) imperatives are a dangerous combination. Badly designed measures could distort markets and investment decisions, causing long-term structural problems, and the ripple effects and law of unintended consequences are inherently unpredictable. It is possible that the demand response to climate change measures will be very strong, exacerbated by taxes and mandatory technical requirements which make the total cost of consuming any carbon-based fuel expensive to the user and much higher than the reward earned by the energy provider. This will greatly increase the focus on energy efficiency throughout economies. *Thus the demand for oil becomes less geared to economic growth.*

Demand for gas may be a beneficiary, but more supply may outweigh this.

Gas is broadly a demand beneficiary of climate change policies, but as already noted, this does not mean that the price goes up, given that increasing supply may outweigh this. In the face of these risks all companies can reasonably do is to understand the variables, lobby against the worst proposals and be vigilant as effects ripple through, especially where other sectors are dragged in. Exiting projects high on the cost curve and other less advantaged assets would render companies more robust to lower demand growth and prices. It is worth re-emphasizing that while in the short term governments may be loath to sign up to expensive policies, the direction is clear and companies are already embedding energy efficiency in their products and processes.

An increasing focus on energy security can cause distortions

Another threat that arises is governments' increasing focus on energy security; this is something of a reversal after a period when globalization and deregulation were dominant. For the oil and gas industry this could manifest as investments that distort regional markets – for example in pipelines or refineries – for non-economic reasons, or it could be that governments limit external participation in certain segments of their markets, constraining the IOCs' ability to shift towards the higher-growth markets.

The ascendancy of the national oil companies

Investors see that significant value has shifted to the NOCs.

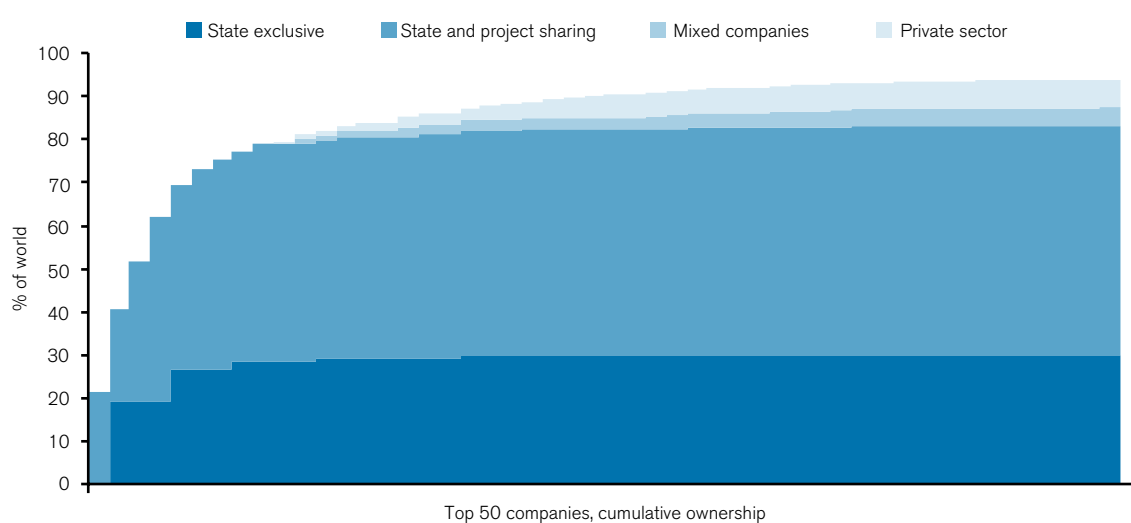
Not only are the vast majority of discovered oil and gas projects located in countries with their own NOCs, but the combination of increasing value retention by the sovereign resource holders and the increasing sophistication and expertise of the NOCs has shifted value away from the IOCs, affecting both access to projects and the profitability of participation. Of course there has always been political risk and raising of the tax take during the life-span of projects, but recent years have seen a very sharp reduction in both the upside gearing to the oil price and the profitability for IOCs. The most extreme examples of this are the Iraq concessions, rewarding companies with fixed fees per barrel, which are essentially service

contracts with no gearing to the oil price. Although several Iraq concessions were given back or not taken up, ExxonMobil signed up to a number, seemingly as a demonstration of good faith to earn the chance to gain more beneficial concessions in the future. Companies may think such deals give them a ‘foot in the door’, but the handle remains on the inside.

It is certainly true that historically there has been cyclical in the terms offered to the NOCs by the IOCs, driven by the need for capital and expertise versus the desire to retain value by the sovereign resource holders, but it is fair to say that there has been a significant step change in the terms of trade and that any amelioration will be from a less advantageous level.

The IOCs are not completely excluded from all these opportunities but they do have to gain their invitation. As shown in Figure 11 (repeating Figure 8 above), about 30% of current reserves are state-exclusive but about 55% are state plus project-sharing or mixed companies and are to a varying extent accessible to the IOCs.

Figure 11: Access to oil reserves 2010: top 50 companies



Source: Energy Intelligence Group Data.

Investors see a reduction in the upside gearing of the IOCs’ share price to the oil price, though downside risk remains.

From an external investor’s point of view, the reduction of the gearing of the IOCs to the oil price detracts from one aspect of their investment appeal, though the downside risk remains (except in the case of pure service contracts). Clearly the degree to which this is the case depends entirely on the portfolio of projects for each company and thus investors need detailed guidance from the companies to understand, as far as commercial sensitivity permits, how they should model the revenue and profit variance given changing oil prices. With sovereign resource holders’ value retention now at such high levels it is arguable that the largest shift has already happened, and with access to funding and expertise still important, it might even be that terms shift back towards the IOCs to some extent; certainly it remains crucial that the IOCs can demonstrate their value added very clearly and that the projects are low enough on the cost curve to be robust both at lower oil prices and in the face of increased tax take.

Investors understand that NOCs are increasingly sophisticated.

Clearly they are all different, in their capabilities, degree of separation from state imperatives and degree of development. These are discussed elsewhere in this report but for the purposes of this chapter they:

- Compete for funding for domestic projects in the face of a collapsing loan market and persistently higher borrowing costs;

- Vary in their ability to reduce or abolish domestic fuel subsidies which could have a material impact on their domestic fuel demand;
- Are diversifying abroad in some cases, given that energy security is a government imperative, and hence competing with IOCs for projects. Their ability to offer infrastructure investment and other 'soft power' incentives distorts this market;
- Are subject, in their domestic markets, to non-economic pressures to contribute to the national good.

A general assumption about state versus private-sector companies might be that the former are less innovative than the private sector, but in the case of the NOCs their investment in R&D and in technology, specific to their needs, far exceeds the R&D investment of the IOCs which, for many years, have focused on cost-cutting and have sub-contracted to service companies such as Saipem, Halliburton, Technip etc.

Investors worry that 'NOC plus service company' excludes IOCs from future projects.

While it seems unlikely that the service companies will be able to deploy large-scale capital into projects, as the IOCs can, where capital is not a major requirement such a structure may be appropriate. For example, as described in Chapter 6, the joint venture set up by Petrofac and Schlumberger involves risked-service contracts and Petronas Carigali and Halliburton have set up a partnership agreement for shale resources.

The scale of investment for the energy industry in 2011–35 is not unmanageable

The IEA (WEO 2011) estimates \$37.9 trillion, or just short of \$1.5 trillion per year, in total investment over the period. It is interesting to note that investment in the power sector is the largest part of the \$37.9 trillion, about 45%, with \$10.0 trillion (26.4%) for oil and \$9.5 trillion (25%) for gas between 2011 and 2035 (in 2010 dollars).

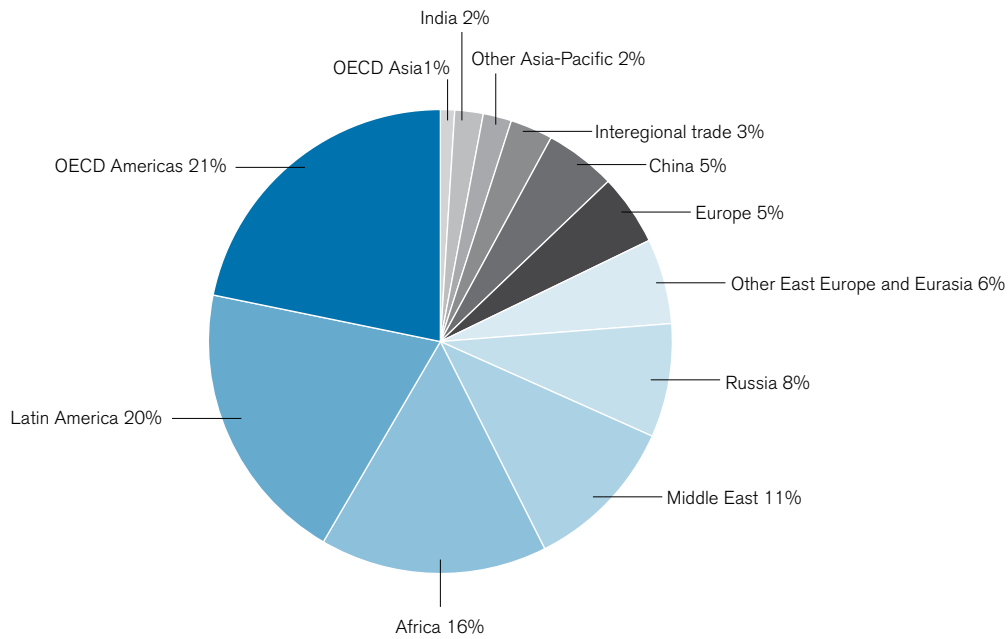
Table 8: Cumulative investment in energy supply infrastructure by fuel in the 'New Policies Scenario, 2011–2035'

	2010 dollars: billion	%
Oil	9,996	26
Gas	9,497	25
Power	16,883	45
Other	1,522	4
Total	37,898	100

Source: IEA WEO 2011.

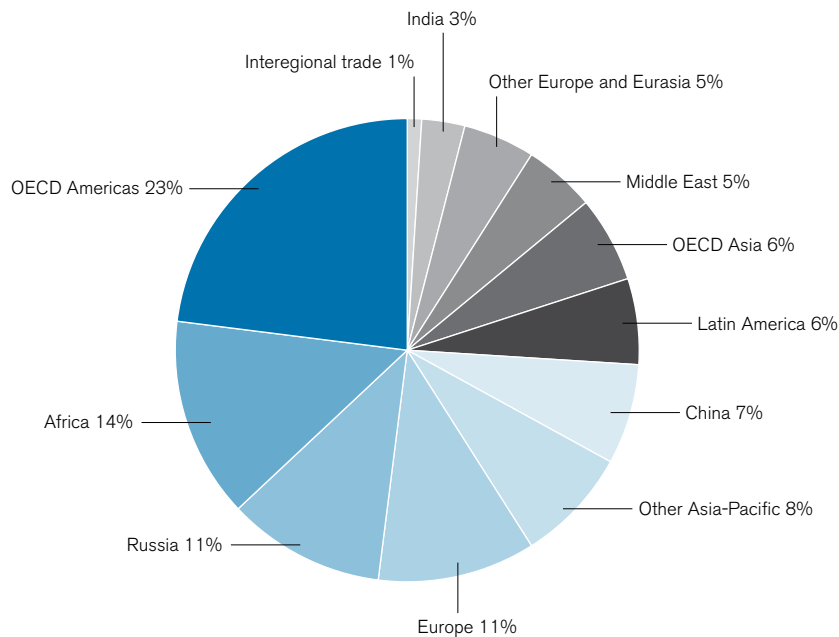
A total of \$780 billion per year for oil and gas may well prove to be high (these figures are based on the 'new policies' scenarios): stronger climate policies would reduce demand for oil and gas. The estimates are designed to balance supply and demand over that period, so clearly if growth is slower and demand is reduced, the requirement for additional capex will be less. These are, however, large numbers (equivalent to investing twice ExxonMobil's market capitalization each year) in the context of, for example, OECD gross capital formation of around \$8 trillion per year. Figures 12 and 13 show the regional distribution for oil and gas.

Figure 12: Oil capex, 2011–35



Source: IEA WEO 2011.

Figure 13: Gas capex, 2011–35



Source: IEA WEO 2011.

Investors worry that IOCs have limited access to new projects.

The regional distribution in Figures 12 and 13 shows clearly that access to resources is predominantly with the NOCs. At a time of increased resource nationalism this is both a major barrier to the IOCs' ability to access future projects and a funding challenge for the NOCs. It contrasts with the current balance in which about half of production is by IOCs and smaller independents. The question for the IOCs is whether there are enough accessible projects to keep them growing, whether they can achieve some kind of accommodation with at least some of the NOCs to gain some access to currently unavailable projects or whether the IOC sector will wane in scale (with consolidation, perhaps, but a diminution nevertheless).

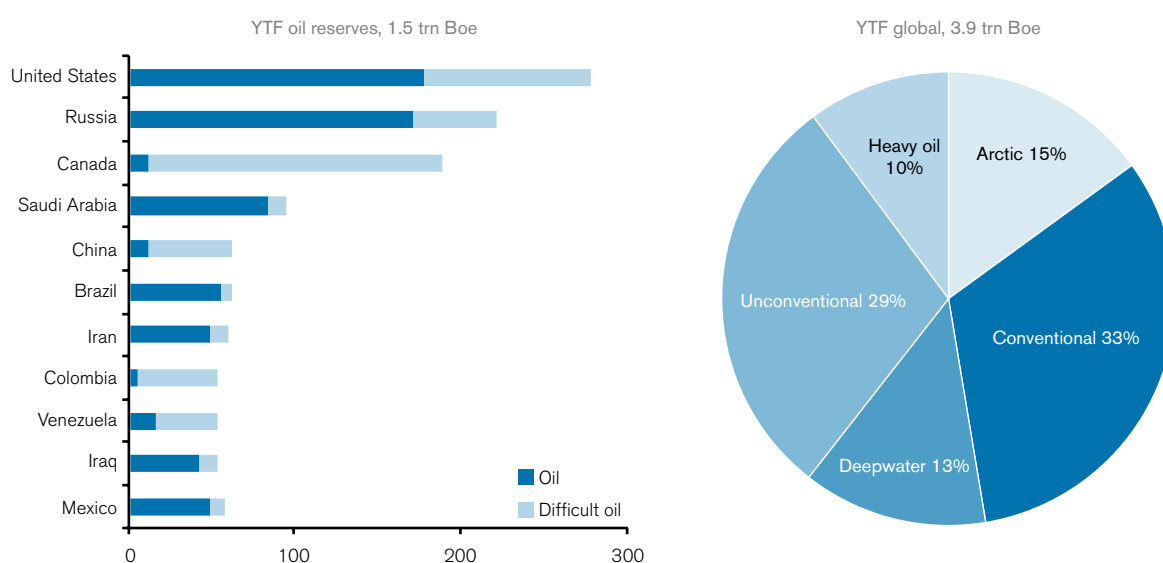
The scope for finding reserves changes the regional balance but increases the technological prize

Investors worry that the IOCs have outsourced too much technical innovation and need to rebuild process excellence: this is crucial for the next era.

Figure 14 shows that while global yet to find (YTF) opens up more opportunities in accessible countries such as the US, Russia and Canada, two-thirds of these are in the more challenging types of resource: deepwater, Arctic, heavy oil and unconventionals. While deepwater and some oil sands are estimated to have operating costs of around \$30/bbl, the new shale plays in the US, Canadian oil sands and the Arctic are at the higher end of the cost curve and are thus more vulnerable to lower oil prices.

The technological and environmental challenges offer an opportunity for the IOCs to use capex and project management excellence as a differentiator.

Figure 14: Global yet-to-find oil reserves



Source: Energy Intelligence – Research and Advisory.

Investors have been invested in and are well informed about the rise of the service companies.

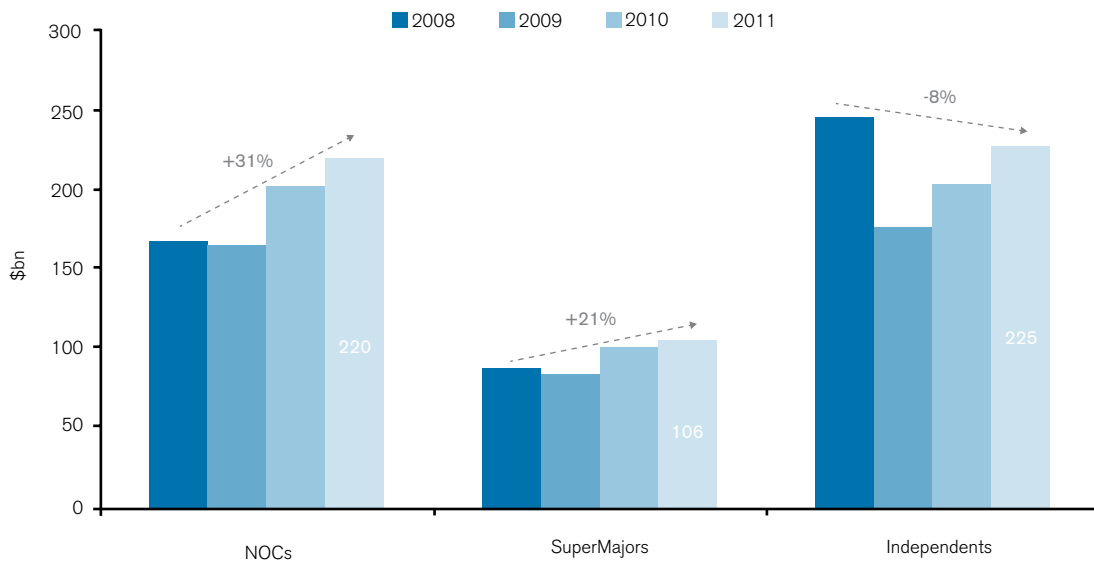
While R&D to sales ratios are hard to derive in a valid comparable form, it is certainly true that the outsourcing used by the IOCs to cut costs over the last 30 years has led to a major shift in R&D to the service companies. Schlumberger, for example, spends about US\$1bn per year in R&D even after the financial crisis, similar to the R&D spend of ExxonMobil (though ExxonMobil may cavil about definitions) and the service companies in aggregate file more patent applications than the IOCs.⁹⁵ The service companies have been instrumental in the development of many of the most important innovations of the last 30 years: horizontal drilling, 3D seismic imaging, hydraulic fracturing and reservoir simulation, for example.

The combination of a narrow margin of excess capacity and a very sharp price rise both attracted capital and brought previously uneconomic projects in from the cold. This has led to a very large increase in the scale of global E&P spending: a compound growth rate of 14% between 2000 and 2011 (from \$130 billion to \$545 billion in nominal terms, with 2012 spending estimated to be close to \$600 billion).⁹⁶ Within this the dominance of NOC spending is clear, as Figure 15 illustrates.

⁹⁵ Source: *The Economist* online, 'Oilfield services – the unsung masters of the oil industry', 21 July 2012.

⁹⁶ Schlumberger Business Consulting.

Figure 15: Upstream capex by type

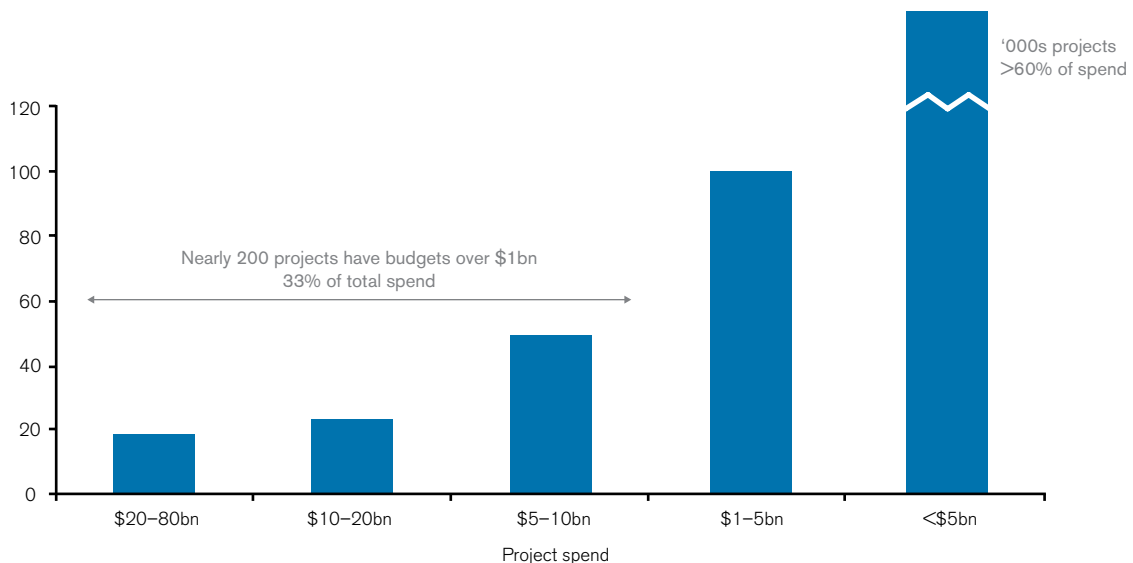


Source: Schlumberger Business Consulting (speech by Andrew Gould, Barclays Capital Commodities Conference, March 2012).

The size and complexity of projects is increasing; not only are these very large-scale blocks of risk capital, but investors worry that this raises the risks of delays and budget overruns.

Both the scale and technical complexity of projects have increased vastly (see Figure 16). Whereas in 2001 only ten companies had annual capex budgets of more than \$4 billion, now more than 30 companies do. Notwithstanding the impact of rising costs on this increase, this scale of financing brings challenges for the companies (especially in an era of much tighter credit conditions) and risk for external investors. Investors have suffered before from companies not being as clear as they might have been about projects running behind time and over budget. While the difficulty of managing such large projects is obvious at a time when input costs were escalating rapidly, clear communication is key to managing investors' expectations.

Figure 16: Project size

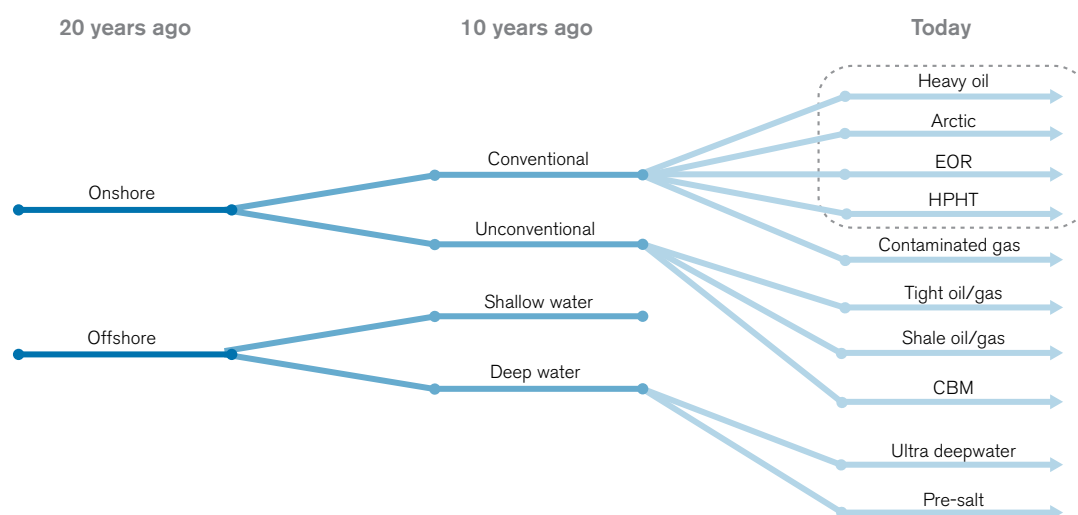


Source: Schlumberger Business Consulting.

Technology excellence is vital, differentiation could be key and investors worry that decades of outsourcing have shifted R&D and technical expertise to the service companies; this becomes more of a problem as projects become more challenging.

Future projects are increasingly technologically challenging, whether very deepwater, at extreme low temperatures or in regions with extreme environmental sensitivity (see Figure 17). For the IOCs to gain access to such projects it is imperative that they build specialist, differentiated expertise in technological development, in project management and in safety procedures to complement that of the NOCs (Statoil's expertise in deepwater is an example of this). While commodities themselves do not have product differentiation or patents as such, there can be effective and valuable intellectual property (IP) in exploration and production technology and in the skills involved in project management and production processes; these can differentiate between companies' levels of success. Demonstration of such capabilities is valuable to investors as well as to potential NOC partners. While we are in no way suggesting that the IOCs bring all technology in house or seek to become more like the service companies, the increasing challenge of future projects requires a very high level of technical expertise, from project design, specific technology, subcontractor choice and continued monitoring to all aspects of safety. IOCs need to demonstrate process excellence, becoming more of a 'systems integrator plus' model than a more fully outsourced model.

Figure 17: Technology development



Source: Energy Intelligence North Sea Market Review 2012.

Cost inflation may abate.

Cost inflation, rather than increasing volume, is the major driver of increasing capex estimates, extrapolating the trends of the last decade when global costs of developing oil and gas infrastructure more than doubled.⁹⁷ Costs rose across the board: materials, personnel, equipment and services, correlating closely with oil prices, levels of exploration and development, and wider economic growth. It is likely that the rapid increases in commodity costs contributed to the proportion of greenfield projects which go over budget: a recently quoted 'general rule' is that 30% of greenfield projects have budget overruns of more than 50%.⁹⁸ Most contracts have a pass-through clause for commodity inputs, so when prices rise rapidly, the service company retains its margin but costs exceed the project budget. Whether increases can reasonably be expected to continue at such a pace is less clear. With slower growth, cost increases of materials and personnel may be less fierce and in a more competitive environment widening contractors' margins may also come under pressure. It seems certain that project costs will continue to rise, but it is impossible to do more than guess at the extent of such increases.

97 IEA WEO, 2011.

98 Schlumberger Business Consulting.

There is potential for considerable improvements in all aspects of project design and management, and this could be an opportunity for the IOCs to become not only more effective on their own account but better partners for NOCs in future projects. Certainly better safety measures and demonstrated expertise in environmentally sensitive regions will be beneficial in dealings with the other arbiters of access to projects: regulators and lobby groups. In the newer unconventional projects there could well be significant technological and process improvement, reducing the breakeven cost.

Cashflow is strong enough to underpin necessary capex.

Although overall, cashflow from operations has been sufficient to fund capex, it is clearly very dependent on oil price. The Apicorp estimate of capex in the Middle East and North Africa (MENA), which is project-based, is \$105 billion per year. The equity part of it, some 57% of the total, is projected to be fundable if the oil price stays above \$90/bbl.⁹⁹ The NOCs also have other calls on their cashflow, such as funding national development in different forms competing with the 'equity' portion, financed internally from retained earnings and state budget allocations.

It is interesting to note the strength of the NOC cashflows in Figure 18. With other tax revenues under pressure in the difficult economic climate likely over the next few years, governments may increasingly use these cashflows for purposes other than reinvestment in the oil and gas sector, but clearly over this time horizon the state sector looks very well positioned.

Figure 19 shows similar estimates for the private sector.

Figure 18: Capex and cashflow: state sector (\$ billion)

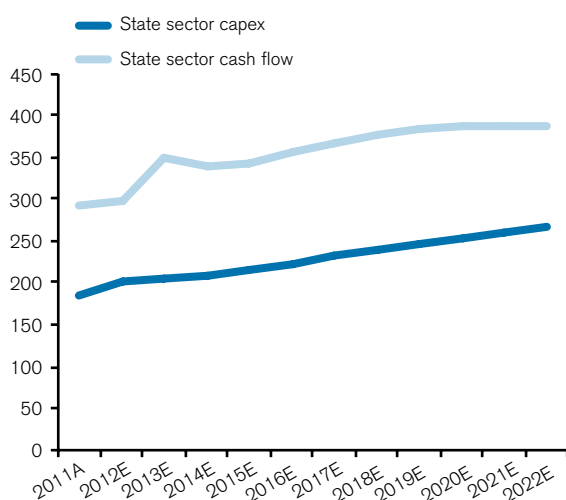
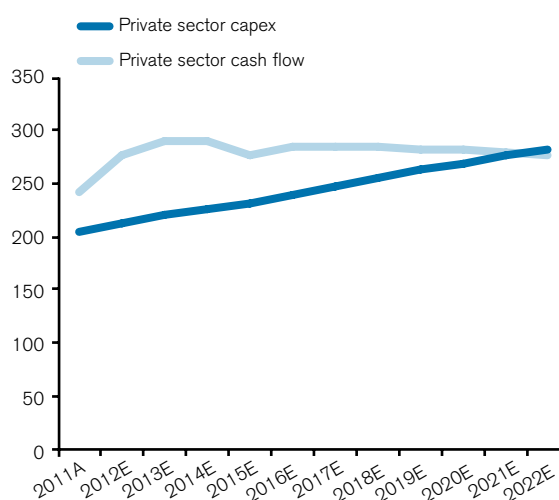


Figure 19: Capex and cashflow: private sector (\$ billion)



Source: Derived from Bank of America Merrill Lynch modelling: oil price assumptions of \$118/bbl, \$120/bbl, \$100/bbl, \$95/bbl for 2012, 2013, 2014, and 2015+, respectively.

This modelling indicates that \$110/bbl is needed for the European majors to cover capex and dividends, though they have the option of flexing dividend growth and making disposals as well as delaying projects if the oil price is lower. This can be seen in the private-sector diagram in the latter years, where the oil price assumptions are lower and cashflow stagnates.

99 Ali Aissaoui, 'MENA Energy Investment in a Global Setting – Assessment and Implications for Policy and Long-term Planning', APICORP's *Economic Commentary*, March 2012.

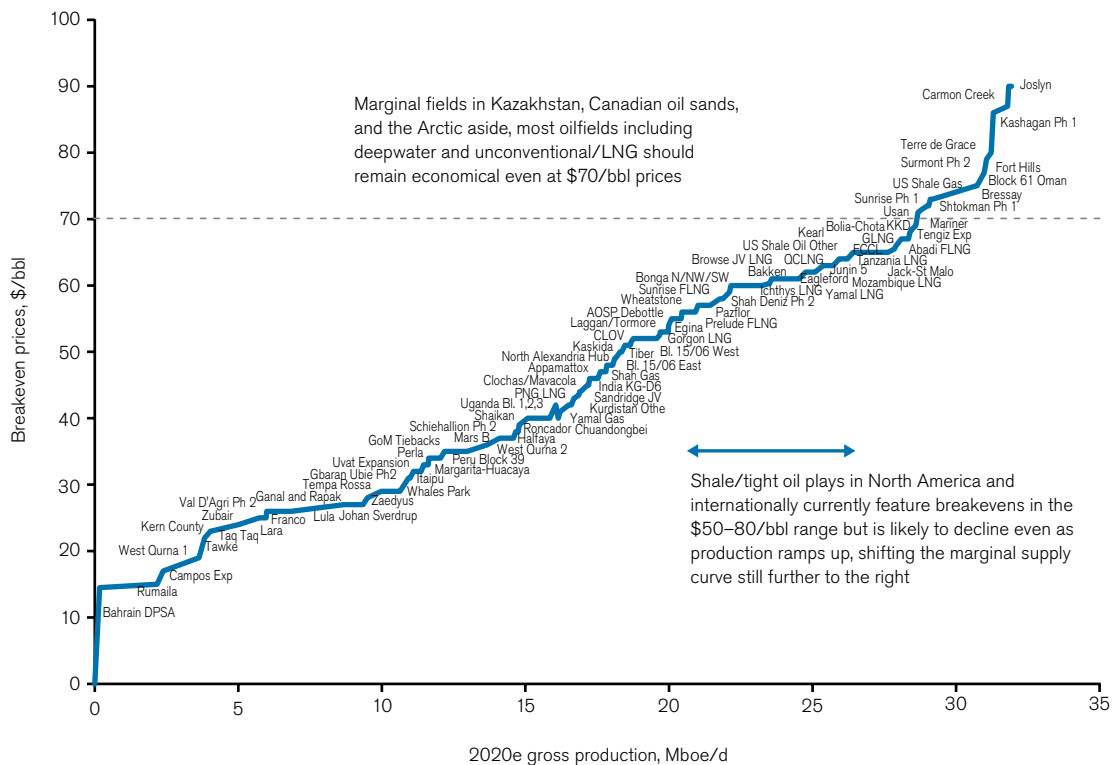
Investors worry about how the oil industry will cope if the long-term oil price stabilizes at much lower levels.

The industry cost curve (Figure 20) shows that the bulk of projects fall below the \$70/bbl level, so could withstand somewhat lower oil prices. North American shale and light oil projects have breakevens in the \$50–80/bbl range, and it is possible that technical progress and production experience may reduce this over time. Most of the deepwater, unconventional and LNG should be economic at the \$70/bbl level, with the most marginal projects being Kashagan and other fields in Kazakhstan, Canadian oil sands (Carmon Creek, Joslyn at about \$90/bbl) and the Arctic (Shtokman). The \$90/bbl level is that of the marginal barrel for the fulfilment of demand predicted in the WEO ‘new policies’ scenario but if the lower price is as a result of lower demand, capex is likely to be delayed (as has been seen with the announcement by Gazprom of the indefinite delay of the development of Shtokman¹⁰⁰).

Investors worry about IOCs having a portfolio too weighted to the high end of the cost curve.

Figure 20 shows estimated breakeven costs for over 100 oil projects now under development, compared with the projected production from those projects. All break even below \$100 (‘breakeven’ does not imply an attractive return on capital or a risk premium). Nearly 30 mbd of production comes from projects which break even below \$70. The critical question for companies is where their projects stand on the cost curve, and this will differ from company to company.

Figure 20: Estimate of breakeven price for incremental oil production projects



Source: Citigroup, 'Zeroing in on Long Term Oil Prices', 4 June 2012.

Gas

Investors understand that gas is always going to be regional and requires more infrastructure; they worry that vastly more supply destroys projections of return on capital for such projects.

Producing gas and bringing it to market requires far more infrastructure than oil: pipelines, LNG trains and terminals etc. Historically much of this infrastructure investment has been funded by selling the gas forward under long-term supply contracts to gas retailers, reducing the funding input of the upstream partners. With the common carrier requirements for pipelines in Europe there are increasing concerns about and erosion of long-term contracts as buyers can see the disruptive effects of large-scale shale gas in the US. Deals do still happen, e.g. the recent BG LNG terminal in Australia funded by selling gas forward for 20 years to a number of Asian companies including Kogas.

Most of the large gas distributors/retailers have been investing upstream to manage their price risk, which makes perfect sense. The vulnerability of a mid-stream company to rapidly rising gas prices was shown clearly in the losses seen by Centrica, subsequent to which the company has added to its upstream gas assets. Some of the gas-producing NOCs (e.g. Algeria) own established subsidiaries to sell gas at the other end of the pipelines (separation from pipeline ownership is required).

Who has the money? The changing investment constituency

History shows that although the resources are where they are, development follows access and the availability of funding; thus there is a disproportionate amount of development in the US despite the projects' position on the cost curve because the market is open and competitive with well-developed capital markets providing funding for a range of different risk characteristics. It is likely that a variety of balancing influencing forces will come into play. If demand is much lower, investment will be delayed, so funding requirements will be lower. If investment is delayed there will be less cost pressure. If investment is inadequate and the oil price rises, projects in more open markets will become profitable. If the NOCs really find funding projects difficult, they may be forced into offering better terms to the IOCs.

From an era of credit expansion to an era of deleveraging: structural, not just cyclical

The next period is likely to be weighed down by the hangover after the credit party of the last decade and thus characterized by deleveraging at both government and bank level, so it is probable that debt funding will be scarcer and more expensive than it has been (quantitative easing being more than absorbed by attempts to repair previous damage to banks' balance sheets). Although it may feel as though there has been a large adjustment already, most countries are only just beginning the process, with the US further ahead than most.¹⁰¹ Increasing bank regulation is inevitable; while it may solve the last problem retrospectively (and will probably cause the next one, unintentionally), there will certainly be indigestion in the system while it is designed and implemented. However, as a credit bubble leads to massive mispricing of risk and the financing of many poor projects (usually property), a tighter environment should still enable robust projects to be funded.

Within this tighter credit environment, the different categories of investors will continue to have different time horizons, risk tolerances and specific mandates (see Appendix 4). They may be investors in specific assets, providers of loans or bond finance (in which case their main concern is viability of the project or company) or investors in quoted companies (with a far closer tie to the short- and medium-term prospects for that company). Although investors are often characterized as being short-term, their focus must match that specified in their investment mandates, though they will always place that in a longer-term context. Unless they are running industry-specific funds, investors are able to compare the growth prospects, risks and valuations across a very broad range and have wide experience of industry life-cycles and responses to change. Quoted companies in the oil and gas sector need to explain to investors

¹⁰¹ McKinsey, 'Debt & Deleveraging: Uneven Progress on the Path to Growth', January 2012.

how they are responding to the structural changes outlined in this report and reshaping themselves to be well positioned to participate in the growth of the next era; investors see their current structures as more of a legacy of a previous era when the IOCs were proxy NOCs for their sovereign nations, and find it hard to believe that this is the best structure for the next, very different period.

How can the IOCs adapt and attract investment?

Co-investment with NOCs

The paradox is that the IOCs are generating cash and deleveraging at a time when they can borrow better than the comparable sovereign, but their cost of equity is high. To reduce the cost of equity, the companies need more growth, which leads to the question of whether it is lack of access to projects, the terms on which access is offered, or areas of growth being masked by other underperforming assets, that is the main problem, or all three. This has not been adequately answered by the companies. It is important for the IOCs whether a funding gap really exists for the NOCs (which does not seem likely), and whether at some point some NOCs will have to improve either access or the terms of projects for the IOCs. For each individual IOC, the critical factor will be developing an offer that provides access to such opportunities. ‘Partnership’ implies some symmetry in a relationship that can never escape the realities of resource control by the NOCs.

Quality versus quantity

In the last era managements focused on volume growth and cost-cutting, but, given the change in the terms of trade with the sovereign resource-holders and the need for IOCs to gain access to projects (and avoid disasters), the next period should be judged by profit and cashflow growth (given the uncertainties, this means focusing on projects at the lower end of the cost curve) and investing in rebuilding in-house technological expertise, project management skills and safety procedures (especially given the extreme conditions in which many future projects are located). This may involve reversing the outsourcing of so many service functions but these will be differentiating characteristics. When growth is scarce, investing for growth can be appealing to investors while cost-cutting in the absence of growth starts to look like a counsel of despair.

Integrated company – or fuel conglomerate?

The justification for being present in so many areas of the value chain without being truly integrated is unclear. Notwithstanding some specific examples of functional integration, company structures look like the legacy of a time when markets were much more closed and the IOCs were proxy NOCs. The question about company structure should at least be asked (again), given the bleak prospects of downstream oil in the IOCs’ legacy markets in the OECD.

However unpleasant, this will involve reconsidering the whole portfolio on a ‘would you start from here?’ basis, applying rigorous hurdle rates with appropriate risk premia (given the uncertainties outlined in this study) rather than internal hurdle rates designed to favour retaining the current portfolio. It may not be the easiest time to sell (many of the assets marked for disposal by BP to meet its Macondo liabilities are still available, whether because of the price or the lack of funding for potential buyers is not clear), but disposing of underperforming assets would clearly release funds for internal investment. It is interesting that, at the same time as there are some worries that needed projects cannot be funded, cashflows appear strong for the IOCs (and more so for the NOCs) unless oil prices fall materially. The IOCs have started this process with some sales of downstream assets (e.g. Exxon’s disposal of its Japanese retail business, BG selling downstream assets and some refinery disposals in Europe) but to change the shape of such large companies more needs to be done.

How could biofuels fit the model?

Although the IOCs have made investments in wind and solar, the main thrust of their efforts is in biofuels. This makes perfect sense, far more so than wind or solar, particularly within the fuel conglomerate model. With blends mandated in some regions already and the potential for more such requirements, the

companies are very wise to be involved in the technological development of biofuels. Their investments broadly fall into two categories: ethanol-related (generally based in Brazil, e.g. BP, Royal Dutch Shell) and those involved in developing efficient processes to extract energy from non-food sources such as cellulose (BP, Royal Dutch Shell, Total), conversion of vegetable oils (ENI, Total) or algae (ExxonMobil). The research centres for these are often based in California (where investment in biofuels is mandated) or in joint ventures with specialist companies.

All the companies emphasize their commitment to biofuels but they also highlight the challenge posed by the much lower energy density in non-fossil fuels, with biomass delivering an average of 5–7 gigajoules (GJs) per million metric tons when it still contains water (wet biomass) and 17–20 GJs per metric ton when dry, compared with 42–45 GJs per metric ton for crude oil.¹⁰² In addition biomass tends to have high logistics costs relative to value as it comes from diverse sources, so if the carbon performance of the whole production life-cycle is included, only the most energy-efficient cultivation and conversion processes can be feasible. There are differences in emphasis; for example, ExxonMobil is very focused on the potential of algae, which it states produces bio-oil with similar molecular structures to petroleum and refined products, and which it estimates to have a higher potential yield – 2,000 gallons of fuel per acre per year of production (gallons/acre/year) – than palm (650 gallons/acre/year), sugar cane (450 gallons/acre/year), corn (250 gallons/acre/year) and soy (50 gallons/acre/year)¹⁰³ and has the advantage of not being a food crop.

From an investor's point of view it would be worrying if the companies were not exploring the potential both as possible incremental business and as a defence against government or regulatory requirements. What investors will be concerned about is whether these investments will be material within an investment time horizon, and what the returns will be. What investors do not want (in any industry) would be early-stage projects to be over-hyped, or very large investments made which are later written off.

BP made the most explicit commitment to a financial target for investment in alternative energy, with \$8 billion committed over ten years from 2005; \$6.6 billion has already been invested, so the target will be reached earlier than 2015. Although not huge, the investment was 4% of BP's total capex, not immaterial, and not disproportionate to the short- and medium-term share of biofuels in the downstream market. BP plans to invest about \$1 billion per year in its alternative energy businesses (subject to opportunities).¹⁰⁴ Royal Dutch Shell has invested \$2.3bn in biofuels over the last five years and has a continued commitment to investigating their potential.¹⁰⁵ Investors will appreciate clarity about the capex invested by all the companies, and the time to maturity of such projects, so that the potential risks and returns can be understood.

Can M&A and mergers boost growth?

M&A has always been a huge factor in the oil and gas sector and remains so even after the financial crisis. Definitions differ: Merger Market gives figures of US\$423,291m for 2010 and \$408,004m for 2011 in the energy sector (out of total global M&A of \$2,277,156m and \$2,236,591m) while Thomson Deals gives figures of \$408,627m for 2010 and \$330,601m for 2011 in what it defines as energy and power (versus totals of \$2,737,357m and \$2,539,058m).

Investors worry about companies which rely on acquisitions to generate growth.

Although investors recognize the power of well-made acquisitions both of assets and companies to enhance or even transform, in general acquisition-driven growth is accorded a lower rating than organic growth. Investors have been burnt by companies that were overwhelmingly acquisition-driven (in many sectors), often making analysis of the underlying growth nigh on impossible and raising questions about sharp accounting.

102 Total website: Alternative Energy section.

103 ExxonMobil website: Algae biofuels section.

104 BP website: alternative energy section.

105 Royal Dutch Shell *Sustainability Report 2011*.

Investors are concerned that acquisitions are often overpaid for, so that even strategic progress is diminished.

Even where an acquisition makes perfect strategic sense, it can be value-destructive for shareholders where the price paid is too high. What shareholders dislike intensely is a large acquisition, always a corporate triumph, followed not many years later by its value being written down massively (sometimes by more than 90%). This is true across the market, but the oil and gas sector is certainly not immune. The time period can also be short; an example is the recent large write-down of shale assets by BHP, only owned for eighteen months.

Could there be large mergers? It is often the case that when an industry faces these major pressures there is an industry-level restructuring; for example, the chemical industry is unrecognizable from its structure fifteen years ago. Clearly investors in the target, who take the cash, are pretty happy at the time, but whether the resulting company gains a higher rating depends on whether the combined group gains a faster growth trajectory, and how easily it can dispose of unwanted businesses. A larger, unfocused company will not attract a higher valuation.

In the face of such uncertainty, and given the different starting portfolios of the various companies, there can be no one right answer. The large IOCs look structurally unclear and ripe for change. Markets being as they are, if the companies do not do this themselves, at some point someone else will. The answer may be to become a large-scale upstream specialist, able to take on the risks of a very large project within a very large portfolio (to some extent BG is moving that way with its upstream growth and disposals of downstream assets), or a fuel conglomerate with very highly advantaged assets, offering shareholders a combination of earnings growth, dividend growth and share buybacks. Some parts of the value chain may belong outside this structure: as retailing has fitted well with hypermarkets, perhaps some refining (especially OECD) will fit better with NOC ownership, or be better suited to being in smaller regional companies well matched to specific requirements. The markets respond to a clear narrative. Conoco and Marathon are testing the former model at the upper end of the mid-cap scale, but we have not yet seen such developments among the largest IOCs.

Conclusions

At its simplest, the world will still want oil, though its demand profile will come under pressure and the price is unlikely to rise as much again as it has in the last decade. The world will also want a lot more gas, but as this is available the price may go down rather than up. As projects become both larger and more risky, there is an increased need for well-functioning partnerships (for both risk management and access to funding).

The NOCs have access to resources, but they vary greatly both in technical expertise and in access to funding. Resource nationalism has enhanced their power but their growth may be limited in the future by the need to partner in increasingly large, difficult and expensive projects. After a long period where the terms of trade have moved only one way, perhaps there is scope for some rebalancing to attract capital and quick access to applying technology efficiently.

The IOCs have expertise, though this can be enhanced, *and access to private capital*, which they can deploy in high-risk upstream projects, too large for the independent E&P companies. They also have less attractive legacy assets and a corporate structure that seems unattractive to investors. By building up their technical and project management skills still further they may be able to gain access to some of the NOC projects, as well as being better fitted for the more challenging projects in YTF. All of the companies have the potential to restructure their portfolios to offer a clearer investment proposition, robust in the face of the great uncertainties outlined throughout this study. There is not one right answer: a large-scale upstream specialist could earn a high rating and a very high-quality fuel conglomerate with a high dividend payout would attract investors with a yield bias. In an era of low growth, companies with growth are typically well rewarded by the markets.

Financial investors have access to funds, but not to the extent that they have had. Risk aversion is high after the previous period of credit expansion and its normal consequence of risk mis-pricing, and in the

face of so many economic and political uncertainties. With growth scarce, investors will be likely to prefer growth and quality. Both could be offered by the IOCs, though with varying degrees of restructuring, but their different portfolios and strategies require more detailed analysis and better communication with managements.

What is clear is that a 'do nothing' option is only delaying the inevitable, and that the IOCs risk being left behind in an energy ecosystem with clear paths for the NOCs and for smaller independents – whether higher-risk, early-stage E&P companies such as Tullow or 'gleaners after the harvest' using technical progress to extract the latter resources from mature fields. Certainly IOCs can acquire portfolios of early-stage assets by taking over small independent companies, but this involves paying a premium and cannot provide enough scale to solve the problem. With such extensive uncertainty it is unlikely that anyone or any company can predict the distant future with any accuracy. The responsibility of managements is to understand the present and immediate future very clearly and be ready to adapt to changes as they emerge. Clearly this is particularly difficult in a capital-intensive industry with long-life assets, but that is the challenge. As the chemicals, steel, airline, and media sectors have proved, industries can change out of almost all recognition and strong global companies can emerge despite enormous challenges. But there is large question mark over which IOCs will still exist in twenty years.

8 Geopolitics and Geo-economics

Key points on energy security

- The main implications of the eastward change in the energy security problem are for governments: the industry will have to be aware and adapt to their reactions. However:
 - In the event of another supply interruption, there is likely to be severe disruption in Asian markets, as only Japan and Korea would be involved in IEA emergency responses. Political interventions would be likely, with conflicting obligations as in the second oil price shock of 1978–79. Companies exporting to or importing into Asia need to review carefully what their legal and political obligations would be during any disruption.
 - The industry and governments might benefit from studying together how to improve regional responses, either through formal links with the IEA or through some form of regional protection.
 - The industry needs to keep track of the larger and possibly changing geopolitical implications of reliance on US military protection for oil export routes from the Middle East to Asian markets.

The oil and gas industry will continue to evolve within the framework of interventions by governments in their own territory and their interaction with other governments. Although the specific features of energy, oil and gas will elicit some of these interventions, they will also be driven by wider policies. One of the challenges for the industry is to understand the scope and force of these policies.

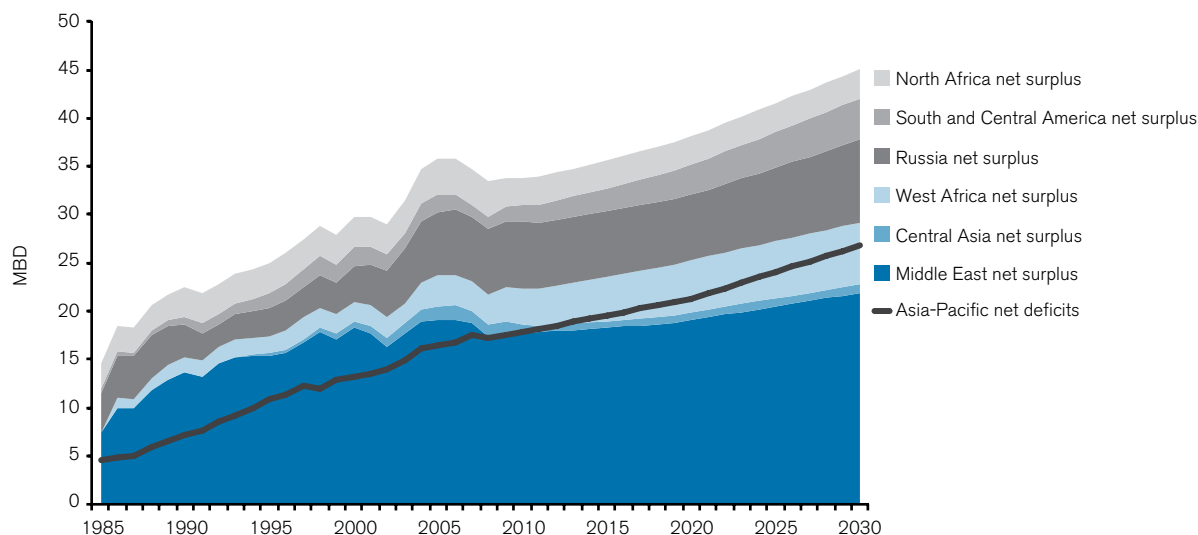
Chapter 2 described the force of new price levels and climate change mitigation policies, and their effects on the transport market are discussed in Appendix 2. Climate change is not the only subject of government intervention, but it is the one, in recent years, where there has been the biggest change. Other chapters have shown how the continually shifting balance between governments and market affects all stages of the industry and its customers.

The main theme of this chapter is the geopolitical implications of the growth of oil consumption in the Asia-Pacific region. Production in the region will not match the increase in consumption, so imports will increase, and by 2020 Asian imports will account for roughly 60% of interregional oil trade. This is not a new phenomenon, but it has reached a kind of ‘tipping point’. From 2010–11, the oil deficits of the Asian markets exceed the oil surpluses available from the Middle East, and this gap will continue to widen.

Figure 21 illustrates this crossover of trends by comparing the export surpluses of different regions with the oil deficits of the Asia-Pacific region. These numbers have been adjusted for logistics (supplies locked in through pipelines etc). The North Africa/Mediterranean region includes available exports from Syria and northern Iraq, and from Azerbaijan through the Baku–Çeyhan pipeline. Sudan exports are grouped with the Middle East surplus. The central Asian surplus is what remains uncommitted after exports to the Mediterranean through the Baku–Çeyhan pipeline and to China through the pipeline from Kazakhstan; Russian exports are reduced by the availability shift to Asia through the ESPO pipeline. The Asia-Pacific deficit is net of the Central Asian and Russian pipeline supplies.

The actual level of trade is probably about 10% higher than the sum of these surpluses: Low sulphur crude is exported from west Africa to Asian markets, and some Saudi Arabian oil is supplied to the refineries in the United States which are owned by Saudi Aramco.

Figure 21: Regional surpluses and Asian deficit



Sources: US DOE *International Energy Outlook 2011* and *Annual Energy Outlook 2012*; BP *Statistical Review of World Energy*; author's adjustments.

Competition for resources (investment opportunities)

The inevitable increase of Asian purchases of oil from suppliers in the Atlantic market is accompanied by increased investment from Asian companies, most of them state-controlled, in the resources in the western hemisphere. According to an IEA 2011 survey, Chinese state-controlled companies had equity production of 1.4 mbd in 20 countries: Kazakhstan, Angola, Sudan and Venezuela are major established sources where Chinese companies produce a significant fraction (more than 10%) of production in these countries.¹⁰⁶ The Chinese companies have also invested more recently in Iraq, East Africa and western Canada.

Chinese competition has an edge over American and European companies since Chinese state-controlled financial institutions can make parallel investments, on favourable terms, in the producing country's infrastructure. This is important as developing oil exporters seek to diversify their economy. The Western oil companies generally do not have the capacity to deliver the same level of support for development outside the oil sector as Chinese and some other Asian companies.

In some cases Chinese or other Asian companies invest in expanding production in countries where European and American companies hesitate to invest because of physical conditions, or the risk of US and UN sanctions, or because companies are committed to codes of behaviour they would have difficulty in implementing in certain countries. The net result may be to increase the global supply of oil but to limit the opportunities for private-sector companies based in the US and Europe.

Competition for supply

Access to trade is different from access to investment opportunities. In the western hemisphere the trade in oil is largely free from government intervention: there are open and competitive markets, with many private-sector buyers and sellers. Short-term prices are established in commodity exchanges in London

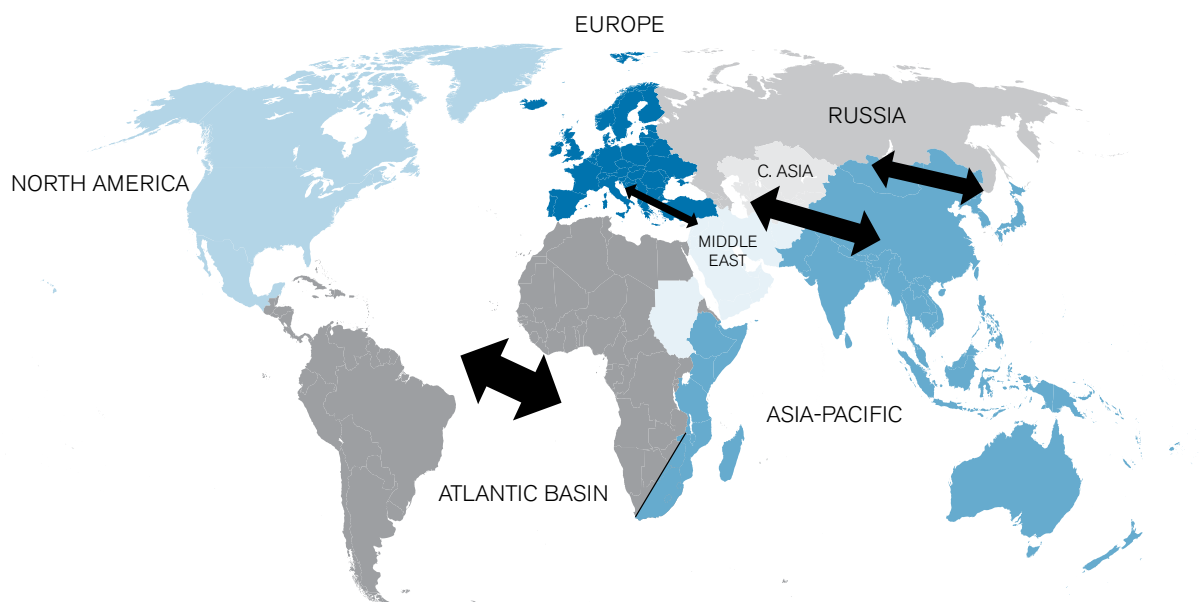
¹⁰⁶ Julie Jang and Jonathan Sinton, *Overseas Investments by Chinese National Oil Companies*, International Energy Agency, 2011.

and New York, and by price disclosure commercial reports. These prices have global influence. As long as the free market in oil in the western hemisphere continues, this competition from Asian buyers may be regarded as a normal phenomenon, driven by the economic needs of Asian consumers. Asian purchases in the western hemisphere will form a relatively small proportion of the trade (about a quarter by 2030).

In the eastern hemisphere the situation is somewhat different. By 2030 something like 60% of the world's oil trade will take place within the Asia region and between Asia and the Middle East. These are regions where, aside from OECD members (Japan, Korea, Australia and New Zealand), state-controlled companies dominate as buyers and sellers. Short-term prices are revealed through the Platt reporting system for Dubai crude, the Dubai mercantile exchange contract for Oman crude, and (through the links by contracts for differences and swaps) between these prices and the much more widely traded Brent price revealed in London. There are two problems: the volumes of Dubai and Oman crude are small relative to the Asian market, and there is not much diversity of supply.¹⁰⁷ The major exporters to Asia are state companies which impose restrictions on the resale of their crude – in other words, they only sell to refineries, bypassing traders who would make a profit on the trade. In the future, the volume and diversity of freely tradable crude may increase with supplies of private-sector equity crude from Iraq, Russia and East Africa. Meanwhile, the restraints on resale and trade in the Asian market may partly explain why prices are higher than they would be if there was more competition: from 1988 to 2012 the price of Saudi light crude to Asian buyers loading at Ras Tanura averaged 3% above the price paid by US or European buyers.¹⁰⁸

The shift in the centre of gravity of oil investment and supply on the global oil map focuses around a 'hinge' consisting of countries which, for economic and logistical reasons, could equally supply to the East or the West: their stability, policies and rate of investment in oil production are of interest globally. The demands and opportunities of these countries need the attention of Asian as well as Atlantic importers.

Figure 22: The new balance of the international oil trade



Note: The arrows show that oil exports from those regions can go either east or west. The size of the arrows is very roughly proportional to their importance (in volume terms). The map is indicative only.

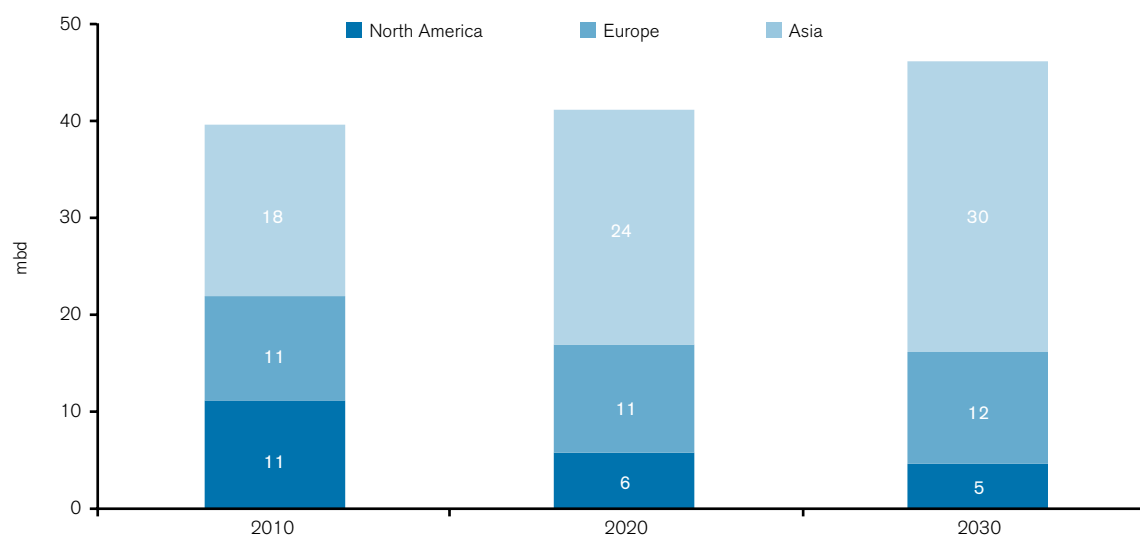
107 Basam Fattouh, 'The Dubai Benchmark and its Role in the International Oil Pricing System', Oxford Institute for Energy Studies, 2012.

108 *Petroleum Intelligence Weekly* data source: crude values at port of loading.

Energy security

The rebalancing of the oil trade also affects energy security. On current policies, it is the Asia-Pacific region that is due to become much more dependent on all imports. For Europe, thanks to flattening and declining oil demand, dependence on international markets is not expected to increase even though production will fall. For the United States, dependence on the global oil trade is expected to decrease as a result of the growing supplies of oil from North America itself. This rebalancing is shown in Figure 23.

Figure 23: Regional deficits requiring supply from global oil markets



Source: US DOE *International Energy Outlook 2011* and *Annual Energy Outlook 2012*; BP *Statistical Review of World Energy*; author's adjustments.

The supposed risks of Middle East supplies

Until now the risks of disruption of supplies from the Middle East, for whatever reason, applied to both the Atlantic and the Pacific markets. Now it is the Asia-Pacific markets that face the greatest risk. Over half the oil consumed in the Asia-Pacific region is imported from the Middle East, compared with 10% for the Atlantic. Atlantic imports from the Middle East¹⁰⁹ are almost balanced by the Atlantic exports of light crudes to Asia.

Table 9: Oil trade, 2010

	mbd	% of importer's consumption	% of total oil imports
Atlantic imports from Middle East	4.6	10	16
Atlantic exports to Asia	3.8	14	24
Asian imports from Middle East	14.3	52	57

Source: BP *Statistical Review 2012*.

The Atlantic importers have an economic interest in avoiding or mitigating the effects of disruptions of supply to Asian markets because international oil prices will respond to Asian market shortages. Importers in the western hemisphere would have to pay international prices to maintain their share of the available supplies.

¹⁰⁹ These include about 2 mbd to the United States for refineries owned by Middle East exporters and about the same quantity to Europe, balanced by Atlantic exports of light sweet crude to the east.

However, there is a contrast between the arrangements for dealing with supply interruptions in the two hemispheres. In the west, OECD members account for 80% of consumption and 90% of oil imports. The International Energy Agency (IEA) is a subsidiary of the OECD.¹¹⁰ IEA countries maintain oil stocks equivalent to 90 days of imports. The IEA's emergency response mechanism (ERM) provides for a coordinated release of stocks in the event of disruptions of physical supply. EU member countries hold 90 days of consumption and have a potential for responding to disruptions if the ERM mechanism does not operate. Asian OECD members (Japan, Korea, Australia and New Zealand) are also part of this mechanism.

China, India and other Asian importers are not part of the IEA system because they are not members of the OECD (although technically bilateral agreements between the IEA and each of these countries would be possible). There is currently no regional political organization under which an emergency sharing mechanism could be built.

China began building strategic stocks in 2001, but there is no mechanism to bring this oil into any regional or global sharing system. The IEA estimated from public sources that by end-2010 crude stocks in strategic storage were 103m bbl (about 95 days of consumption), and increases in capacity to 207m bbls by 2013 and 500m bbls by 2020 were planned.¹¹¹ A disruption of Middle East oil supplies would therefore lead to free-for-all competition for the available oil in the Asian hemisphere. The severity of Asian disruption would lead to very high prices which would not only attract supplies from the Atlantic but also be translated directly into the international oil prices that Atlantic countries would have to pay.

Is equity oil secure?

Chinese and other Asian companies' equity oil in foreign producing countries is not necessarily useful for oil supply security. In the event of a disruption to Middle Eastern supplies, Chinese production in the affected country would also suffer. In the event of a political dispute leading to either UN or US sanctions on exports from a particular country (as in Libya, Sudan, Burma and Iran) the availability of Chinese equity crude from these countries would depend on the attitude of China in the dispute concerned, and the response of those countries to that attitude. In the last resort, it is the host countries that will decide on any interference with the normal commercial flow of their oil. Nevertheless, in times of crisis companies will be better off with some oil somewhere than with no oil anywhere. Oil 'somewhere' gives the company a bargaining position for swaps and trade in the international market and also gives it a source of valuable market intelligence.

Gas security

Security for gas differs in some respects from security for oil.

- Gas is mainly a regional market, and is likely to remain so (see Chapter 4). Over 80% of the world's gas consumption is supplied from production in the country in which it is a consumer, or from neighbouring countries, whereas only about 40% of oil is supplied locally or regionally and the balance must come from the global market.
- Demand in each regional market is uncertain because of its link to the future mix of fuel for power – itself subject to policy uncertainty; the supply outlook has been transformed in North America by the development of shale gas and there are possibilities that this might be replicated elsewhere – notably China.
- Large discoveries of conventional gas off the coast of East Africa add to the potential supply in Asia.
- Gas security involves reliability of continuous supply to consumers, so that at the national level shortage and resilience of networks are important issues.

¹¹⁰ It is not, as sometimes described in the press, 'the consumer countries' watchdog'; it is only the OECD countries' watchdog.

¹¹¹ *Oil and Gas Security: Emergency Response of IEA Countries: People's Republic of China*, IEA, 2012.

Only about a third (30% in 2010) of interregional gas trade is carried in ships: the remainder is moved by pipeline. The LNG portion is likely to increase as a result of the increased demand for gas in China and India, most of which will be supplied in this form from Qatar, Australia, Indonesia and East Africa. Table 10 shows the diversity of supply for Japan. It shows the relatively high dependence of Europe on Russian pipeline supplies and the importance of regional pipeline supplies (from Canada) to the US in 2010. Individual countries in Eastern Europe have a dependence of 40% or more on Russian supplies.

Table 10: How much do gas imports matter?

2010	Imports as % of consumption					
	<i>Total imports</i>	<i>All imports</i>	<i>From region</i>	<i>From Middle East</i>	<i>From Russia</i>	<i>From elsewhere</i>
	<i>BCM</i>	<i>%</i>	<i>%</i>	<i>%</i>	<i>%</i>	<i>%</i>
China	16	15	9	2	0	4
India	12	20	0	18		2
Japan	93	98	65	22	0	11
Europe	270	55	12	9	26	7
US net	75	11.6	10.2			1

Source: BP Statistical Review 2011.

The geopolitical considerations connected to the LNG trade are similar to those affecting the oil trade, but there are important differences.

In Asia, an increasing proportion of LNG will originate from private-sector exporters in Australia, East Africa as well as Indonesia, and will be bought by private-sector power utilities. The market is far from transparent. There is no short-term gas pricing point and prices are linked to oil prices rather than to gas-to-gas competition. This may change, but overall the future gas markets in Asia look unlikely to be dominated by state-controlled exporters.

For gas, the geopolitical risks are therefore focused on pipeline trade: regulatory risks on the pipelines between Canada and the US, and political risks between Russia and Europe. In both cases the pipelines provide a mutual dependence: for the exporters, alternative markets are distant and expensive to reach. For the importers the alternative is LNG.

In North America the prospect of self-sufficiency or at least marginal gas exports is now very real. Canadian pipeline exports to the US are an important part of this. If pipeline expansion is frustrated by environmental policy decisions, Canadian exports may move to Asia. There are already several projects to provide pipelines to the Pacific coast and export LNG terminals.

In Europe the political focus is on the dependence of Russian–European gas trade on pipelines which transit through Ukraine. There has been a history of disputes between Russia and Ukraine over gas pricing. In 2009, Russia cut off supplies to Ukraine for a short period and the shock of this shutdown had a knock-on effect on EU perceptions of gas insecurity. This dependence has become an iconic issue and the events of 2009 and subsequent short interruptions of supply have led to two responses:

- The Russian state monopoly Gazprom has invested with German import partners in a pipeline under the Baltic (Nordstream) to bypass transit countries, and has a project (South Stream) for a pipeline under the Black Sea to supply its customers in the Balkans. These two pipelines would reduce the dependence on transit through Ukraine to a very low level.
- A series of projects have been proposed for gas pipelines to bring Central Asian gas to southeast Europe. The most ambitious, ‘Nabucco’ project for importing gas from Azerbaijan and Kazakhstan seems unlikely to secure supplies or investors despite political support from the European

Commission. Less costly alternatives are being considered for importing gas from Azerbaijan. Imports of Kazakhstani gas across the Caspian Sea to support any of these schemes is less certain: the economics of a pipeline under the Caspian are severe, the politics are controversial because of long-standing disputes over maritime rights, and finally the opening towards more profitable Asian markets via pipelines to China is more attractive to Central Asian exporters.

The key geopolitical gas issue is therefore the European dependence on Russian gas supplies. This has to be placed in the broader context of political, economic and security relations between Europe and Russia.

For Asian gas importers, the LNG supply is potentially more diverse, is less dependent on specific bilateral links, and mostly avoids the Persian Gulf.

Military matters

The final security question for Asian and therefore for global oil security is who will provide military capability to defend the integrity of weak states and to protect sea routes, pipelines and ‘choke points’ against terrorists and coastal or transit powers that might otherwise use their blocking potential to achieve foreign policy objectives contrary to the interests of the importing country. The United States is currently the ultimate military guarantor of the shipping lanes. Michael O’Hanlon, a national security expert with the Brookings Institution, estimates that the US spends \$50 billion a year on protecting oil shipments.¹¹² While China is projecting its naval power further, notably through its participation in anti-piracy efforts near Somalia, its military expenditure and actual capacity for this task remain low.¹¹³ At present no other major power can take on the role.

The ability and willingness of the United States to protect international sea lanes is of benefit to all exporters and importers who depend on international oil trade. It also creates a dependence on the US which is not necessarily welcome.

The new factor is the greatly reduced dependence of the United States on imports from the Middle East. But a turn-about on naval and air commitments to secure shipping lanes should not be expected. As mentioned earlier, the price the US pays for its own oil would be affected by supply disruptions in a trade zone on the other side of the world. Beyond energy security, wider political considerations play a critical role in its willingness to maintain its military and naval presence in the Gulf and Indian and Pacific Oceans. Of greatest importance is protecting the interests of exporting and importing allies, which would be negatively affected by oil trade disruptions.

Another factor that could affect the predominance of the US in the choke points of the Strait of Hormuz is the emergence of post-revolutionary governments in the Middle East. New, democratically elected governments may change the terms of military collaboration with the US. The question for the future is whether a more collective approach to seaborne oil security can be developed to lessen the financial and military burden on the United States, reduce the political sensitivity of operations for exporters and minimize the threat that this may be supposed to present to other countries dependent on oil imports.

More recently protection of shipping against Somali pirates has been secured by naval forces from a number of countries, coordinated across the maritime security patrol area in the Gulf of Aden, with participation from an EU naval force, the US, China, Russia, India and Japan. In the Straits of Malacca the Indian Navy is supporting actions by Indonesia, Malaysia and Singapore. In both areas merchant ships have used armed guards, from the private sector, to resist pirate attacks. State-based interference with shipping would need to be dealt with differently, with the risk of escalation to naval confrontation or conflict, for which a much deeper diplomatic and military coordination would be required to protect peaceful shipping. There have been examples of other countries’ participation in the protection of Middle East sea lanes: for instance, in the ‘flagging’ of tankers through the Strait of Hormuz in the 1980s during the Iran–Iraq war.

¹¹² *Wall Street Journal*, 27 June 2012.

¹¹³ International Institute for Strategic Studies, ‘China’s Three-Point Naval Strategy’, *IIS Strategic Comments*, Vol. 16, Comment 37, October 2010.

Elsewhere, participation by other countries in naval protection has other implications. Problems could arise in the South China Sea, in which China, Taiwan, the Philippines, Vietnam, Brunei and Malaysia have overlapping territorial claims over areas with vital shipping lanes and potential oil and gas deposits. The security of oil imports (or exports, in the case of Brunei and Malaysia) is important to all these countries. Managing the security of shipping lanes in this sea will be an increasingly confrontational issue: a stronger American naval presence will antagonize China, while China's deployments will surely be of great concern to its neighbours.

The question for governments for the future is whether to seek a more collective approach to more general seaborne oil security, which would lessen the financial and military burden on the United States while maintaining the confidence of other countries. Cooperation against piracy has provided a useful experience but cooperation against deliberate state interference would require a much more careful structuring of the commitments and some way of coordinating action in ways that would not prejudice disputes over sovereignty. This would be very difficult to achieve.

The oil and gas industry will be affected because insecurity of the sea lanes will lead governments of importing Asian countries to promote domestic or neighbouring sources of supply rather than international ones.

9 Conclusion

The oil industry can no longer rely on its monopoly of the transport market. The vehicle industry is replacing oil with more efficient vehicles, and biofuels are replacing oil products as liquid fuels. This is driven both by the increase in oil prices since 2005, and by government policies limiting carbon emissions. Since 2011 all major importing countries have adopted strong policies on carbon emissions and vehicle efficiency. These secure markets for efficient automobiles, rather than for oil. As current policies are unlikely to achieve their aims, it is probable that stronger policies will be introduced. The result will be to flatten and reverse growth in the use of petroleum in transport in developed countries, and slow its growth in developing countries.

The major private-sector oil companies have a legacy of refineries and distribution networks in the 'no-growth' markets. Companies will not invest in modernizing them for a short and uncertain future except where there are strong continuing circumstances. Refineries will close, brands will disappear, and more products will be imported. Governments will be less able to rely on major international companies to secure supplies. The traditional model of integrated oil companies cannot easily be recycled into downstream markets which are more and more being broken up by advantages for local resources and the impact of local regulations.

Upstream, 'peak oil' is proving a misleading idea. The foreseeable problem is not finite resources but the rate at which these very large resources can be converted into reserves for potential production. Technologies are developing which are creating new reserves of 'unconventional' oil, as they have already done for gas. Reserves of oil and gas have both more than doubled since 1980 – faster than the increase in production. These technologies have more places to go: many of them outside the existing oil-exporting countries. These new areas are opening a field of growth for private-sector companies that was not foreseen a few years ago. The companies also still have opportunities for collaboration with state companies, in half the world's current oil reserves, provided they meet each country's terms and conditions. Technology is the master key to both sets of opportunities: downstream affiliations are not.

These factors combined lead us to conclude that there is no long-term escalator for oil prices, with demand vulnerable to other industries and supply growing from 'unconventional' sources and new areas. There is no clear trend; all depends on investment by competitors for the transport market and on the creation of new reserves. Investment in expanding production by some state companies, where their economies depend on oil exports, is problematic. Their governments may choose to keep oil in the ground to gain time to diversify their economies.

There is scope to expand the use of gas in most parts of the world, but in each country this depends on government policies for power generation, coal, nuclear and renewables, rather than on factors intrinsic to the gas industry. The industry needs to find prices both to expand demand and increase supply. Gas cannot rely on a golden age beginning now.

This report has also considered the industry from outside. For investors who look for growth in value or volume, many private-sector companies seem configured for the last era and not the next; their public strategies look recycled, not renewed. Growth in volume is challenged, especially downstream. Upstream growth of volume or value depends on the terms offered by state companies and the success of new technologies.

Few companies seem to question the arguments for vertical integration. There is a legacy of implied obligations to 'meet demand' as in the previous status quo. Choices are emerging within the industry in which some companies become energy conglomerates while some become focused upstream or downstream companies.

The energy security problem has moved to Asia. Asian markets now absorb all the oil the Middle East can supply, and will absorb more. This changes the security of supply problem. For Western countries, the risk is price, not supply. For most Asian countries, continuity of supply is also a risk and there is no international mechanism (similar to the IEA) to manage that risk

This raises a political question: how far will the US go to defend sea lanes which mainly benefit Asian countries, and will Asian countries seek to provide their own protection, individually or collectively?

Oil and gas is a special industry, but it cannot isolate itself from broader trends which challenge its markets and present new opportunities. All who are in the industry or who deal with it need to share clear thinking and say what they mean to do in this changed future.

Appendices

Appendix 1: Climate Change Policies: Restricting Emissions of Greenhouse Gases

The problem: uncertainty

Caesar: 'The Ides of March are come'
Soothsayer: 'Aye Caesar; but not gone'
Shakespeare: *Julius Caesar*, Act III, Scene 1

The soothsayer had never said exactly why Julius Caesar should beware the 15 March, 44 BC, but after this exchange Caesar walked into the Senate, where he was murdered anyway.

The threat of climate change is a little like the soothsayer's prediction. We will not know whether it is true until it has happened. The scientists do not tell us exactly what the climate will be in 2050, or at any other date. Their results have a wide range of probabilities, which are ignored in popular presentations, and in the threshold of '2 degrees – 450 parts per million (ppm)' in policy debates. Under current policies, increases of 3.5°C to $\pm 7^\circ\text{C}$ by 2100 are projected in the MIT *2012 Energy and Climate Outlook*.¹¹⁴

Over the past 30 years climate scientists have grown increasingly confident that there is a warming trend in the global climate. Most believe that their models not only explain the observed phenomena but cannot exclude the possibility that the warming has 'most likely' (to an extent which cannot be specified with certainty) been at least partly caused by man-made ('anthropogenic') emissions of 'greenhouse gases' such as carbon dioxide, methane, nitrous oxide and other industrial gases. There is even less certainty about the extrapolation from global climate to climate in different regions.

Economists can see climate change as a 'problem of the commons' where government intervention (by taxes or quantitative restrictions) is justified to prevent the destruction of a shared asset by the sum of individual rational actions.

Politicians see demand for restricting emissions of greenhouse gases as one among many calls on their political responsibilities. At the time of writing (2012) the prime responsibility in most countries is to improve the economic situation, which is likely to depress incomes, government spending and investment for some years to come. Climate change policies have slipped down the agenda because so many appear to involve short-term increases in costs to consumers or taxpayers, or both. The problem is acute when individual countries or regions (such as the EU) try to adopt more aggressive climate change policies than their economic competitors.

If the threat of climate change has grown more convincing, have the policies designed to mitigate it grown more credible? So far, they are not credible as a response to the threat. Given the immense difficulties, they are credible as work in progress, but further 'progress' – more severe policies – is likely to be slow, given the many difficulties:

- The need for global action: one country cannot protect its own climate by its own actions;
- Uncertainties about the rate of change in the climate, given the wide range of probabilities on the assumed link with emissions;
- Uncertainties about future emissions: economic, technology and energy forecasts over a 50-year period bring extra degrees of uncertainty;
- The immediate economic cost to consumers and taxpayers of many interventions designed to reduce emissions;

¹¹⁴ MIT Joint Program on the Science and Policy of Global Change (2012), *2012 Energy and Climate Outlook*, Massachusetts Institute of Technology, Cambridge, MA.

- Uncertainties about future costs of low-carbon energy technologies;
- Lack of political and social consensus on how to balance costs in the near future against benefits in the distant future: these were illustrated in economists' debates about the Stern Report of 2006. It is easier to say 'Avoidance of catastrophic climate change' than to attribute economic values to it.
- How to implement the United Nations Framework Convention on Climate Change (UNFCCC) obligations, confirmed at Cancún, that 'Parties, especially developing country Parties that would have to bear a disproportionate or abnormal burden under the long-term cooperative action under the Convention, should be given full consideration'.¹¹⁵ This refers to countries which depend on the export of fossil fuels.

The slow-moving international negotiations are being overtaken by parallel actions of governments, including those of China and the United States; these trends are reinforced by business responses to the opportunities to supply capital goods and systems which avoid emissions and the related use of energy. This combination is a tipping point for perspectives on the future of the oil and gas industry.

Work in progress

There are three streams of work to respond to the threat of climate change:

- The formal, slow and complex international negotiations;¹¹⁶
- The policies adopted independently by different governments, including those of the US and China;
- Business investment and initiatives that are not necessarily dependent on the details of government policy.

As the first two streams move ahead, the emphasis is changing from 'top-down' internationally agreed government direction to 'bottom-up' government and private actions moving more or less in accord – represented in the international process by the National Appropriate Mitigation Action (NAMA) plans. With this shift, the business stream is gaining force from the interests of businesses which see opportunities in supplying the goods and services which will provide decarbonization – helped by unreliable government intervention in some cases, but ultimately representing risky investments for the future. The question for the oil and gas industry is whether the momentum of this business stream changes the force and speed of the whole carbon control trend, such that oil and gas companies should pay much more attention to the boundaries of their industry which these other businesses will contest.

International agreements

Given the difficulties, there has been credible progress (see Box 3), which provides a brief history of international climate change negotiations. They falter, but do not reverse. Major recent steps forward were:

- Political agreement at the end of 2009 (in the 'Copenhagen Accord') of the US and major developing-country emitters such as China and India to a 'pledge and review' policy process;
- Formalizing 'pledge and review' into the international legal process at Cancún in 2010;
- Agreement in Durban to extend the Kyoto Protocol and negotiate a global agreement, including developing countries, on reducing emissions.

¹¹⁵ UN FCC CP/2010/7/Add 1.

¹¹⁶ For a summary of the history pre-Durban, see Smith School of Enterprise and the Environment University of Oxford (2011), *International Climate Change Negotiations: Key Lessons and Next Steps*, Smith School of Enterprise and the Environment University of Oxford.

Box 3: International climate change milestones

The UN Framework Convention on Climate Change (1992)

- Committed all signatories – includes the US, China, and oil exporters, to ultimate objective of stabilizing atmospheric concentrations of greenhouse gases at levels that would prevent 'dangerous' human interference with the climate system.
- 'Common but differentiated responsibilities'.
- 'Annex 1' countries (essentially the OECD plus Russia, ex-Soviet and Soviet-bloc states) to reduce emissions.
- 'Annex B' countries (OECD) to support mitigation and adaptation elsewhere.

The Kyoto Protocol (1997) (not ratified by the US)

- Most Annex 1 countries agreed targets adding up to 5% reduction from 1990 by 2012.
- Clean Development Mechanism (CDM) Annex 1 countries could meet part of their reductions by buying credits created by investing in developing countries (China had most investment).
- Fund for adaptation, financed by revenues from the CDM.
- Mechanism for transfer of technology.

Bali Action Plan (2007)

- Addressed political issues: common but differentiated responsibilities, special position of developing countries, funding, technology transfer and capacity-building, dealing with adverse consequences of responses.
- Reduce deforestation etc. (REDD).
- Developing countries to prepare Nationally Appropriate Mitigation Actions – for support from rich countries.
- Efforts to include developing countries (with different obligations).

Copenhagen agreement 2009

- (No substance)
- Copenhagen Accord (2009–10).
- Main emitters (including US, China) to 'Pledge and Review Policies and Measures' for 2020–30.

Cancún agreements (2011)

- Target 2°C ceiling for warming.
- Reduce deforestation and degradation (REDD and LULUCF).

Durban Convention (2011)

- Kyoto agreement to extend beyond 2012: but Russia, Japan and Canada will not participate.
- By 2015 negotiate 'outcome with legal force with commitments for developing countries' from 2020.
- Confirm \$100 billion annual target for funding adaptation and mitigation (Green Climate Fund).

There are different estimates of the effect of the Copenhagen Pledges (represented roughly in the 'New Policies' scenario of the *IEA World Energy Outlook 2011*). These suggest that the target will not be met. As evidence of the impact of climate change becomes more convincing, it is likely that policy and other

actions will adjust. The outcome represented by the '450 ppm' scenario drawn up by the IEA¹¹⁷ is probably not now feasible, even if the policies it assumes were in fact adopted soon.

Parallel national policies

The EU

2005 EU Emissions Trading System (ETS)

ETS was introduced in 2005 before the Kyoto agreement came into force, but after it was negotiated. It provides for a cap on EU emissions, with different allowances allocated to different countries, sectors and large energy-users. ETS will continue if Kyoto II negotiations are inconclusive. The International Carbon Action Partnership (ICAP), which is working on rules for an international carbon trading system, includes some US states as well as countries party to the Kyoto Protocol. Australia has announced that it will join the partnership.

After initial problems that were due to an oversupply of allowances, the ETS system has been tightened so that allowances are issued on an EU national basis and the proportion auctioned (rather than grandfathered) increases annually. The caps will apply to more major energy users from 2013 and (from 2012) to international airlines when they bunker in the EU. Installations covered by the scheme are responsible for nearly 50% of EU emissions of CO₂ and 40% of all the EU's GHG emissions. Carbon markets in 2010 were estimated at \$135 billion. Prices have fallen since. The 'carbon price' has proved somewhat unstable and a stabilizing mechanism is being considered. If similar measures are not imposed outside the EU (or exemptions granted in the EU), there is a risk of 'carbon leakage' as carbon costs enter into the location decisions made by energy-intensive firms. A proportion of the proceeds from the sale of allowances is to be set aside in future to co-finance new energy demonstration projects. Credits will be allowed, under conditions, for emission reductions achieved by investment outside the EU under the Kyoto Protocol CDM.

The European Commission's October 2011 proposals to revise the EU fuel quality directive will require tracking of carbon emissions up the supply chain. The objective is to identify life-cycle emissions for oil feedstocks and products, using either actual emissions or 'default' figures estimated by CONCAWE, an industry technical organization. The revised proposals are still progressing through the EU system but are likely to be supported by the European Parliament. The result will be differentiated GHG values for high-carbon fuels, including tar sands and shale oil. This will affect the emissions allowed under the ETS.

UK Climate Change Act of 2011

This act goes beyond international commitments, or negotiations about commitments, on climate change mitigation. It establishes a legally binding target of an 80% reduction in GHG emissions by 2050 compared with 1990. Five-year carbon budgets are to be established, with review and reporting requirements. Credits for GHG reductions outside the UK will be limited. The act introduces new obligations for measurement, reporting and publicity for businesses responsible for GHG emissions, and permits the government to introduce new restrictions through secondary legislation. As the underlying economic and energy outlook changes, so too will carbon budgets. The inevitability of changes undermines the credibility of actions based rigidly on current budgets.

The US

Climate change objectives (mainly related to R&D) appeared in the US Energy Act in 2007. The Supreme Court has agreed that the Environmental Protection Agency (EPA) can regulate for greenhouse gas emissions. The EPA and National Highway Traffic Safety Administration (NHTSA) agreed CAFÉ regulations in 2010 and 2011 (enacted in 2012) which will significantly reduce US oil consumption and therefore emissions (See Appendix 2).

117 IEA (2010, 2011), *World Energy Outlook*, International Energy Agency, Paris.

Cap-and-trade systems are familiar in the US from the success of the 1990 scheme for reducing SO₂ emissions. Federal and state programmes exist for capping and trading NO_x and VOC emissions. Progress on CO₂ capping systems has been more difficult.

Federal proposals for a cap-and-trade system for CO₂ have been approved by the House of Representatives but not by the Senate. California has passed cap-and-trade legislation that is subject to California Supreme Court review. Seven US states and four Canadian provinces have agreed a 'Western Climate Initiative' (WCI), which has not achieved much political support. There is a regional greenhouse gas initiative in the northeast US, which has achieved patchy support. Climate change policies in the US proceed through a variety of political institutions. Progress depends on their place in wider political priorities, but the continuity of initiatives such as the higher CAFÉ standards is likely, since they are supported also by the national security objective of reducing oil imports.

China

China's first comprehensive plan to combat climate change appeared in 2007, but China continued to resist the idea of making internationally binding commitments to target reductions in emissions. It was only prepared to talk about reductions in carbon intensity (CO₂ emissions per unit of GDP). The breakthrough in the Copenhagen Accord (which was not a legally binding agreement) at the end of 2009 was that China was willing to put such targets through a 'pledge and review' process, and the US was prepared to accept that as a valid contribution. In the Durban convention at the end of 2010, China went further in undertaking to take part in negotiating an agreement 'in legal form' which would contain its commitments beyond 2010 (see above). Meanwhile the Chinese programme continues under its own momentum. This quickened in 2011 with the inclusion, for the first time, of a CO₂ intensity reduction target in the country's five-year development programme. There is a separate 12th Five-Year Programme (FYP) on greenhouse gases, which assigns each Chinese province a carbon-intensity reduction target for the period 2011–15.

Unlike the developed world, which has already gone through a local pollution clean-up period, China faces significant challenges in cleaning up its local air, water and land pollution. In addition to CO₂, the Chinese 12th FYP has other binding targets to reduce chemical oxide demand (COD), SO₂, NO_x, ammonia and nitrogen.

One significant development in China is the government's desire to control the country's total energy demand: the policy-makers have realized that the country's energy supply cannot run after the unchecked demand, and that only through severe demand control measures can the Chinese economy be brought back to a more sustainable development path. The 12th FYP talks about imposing a ceiling on Chinese energy demand, at 2.7 billion toe by 2015,¹¹⁸ against 2.2 billion toe in 2010.

Implications for the oil and gas industry

It seems certain that over the long term the demand for oil and gas will be curtailed below current trends. The uncertainties about the timing and scale of transition to low carbon economies mean that the industry can be confident of a continuing demand for oil and gas, even at levels of demand significantly lower than in current projections. However, as discussed in Chapters 2 and 3 of this report, the oil and gas industry will face changes in its principal markets. In the transport market, vehicle manufacturers will compete against a greater share of consumers' expenditure to be spent on more efficient vehicles, at the expense of fuel, and the promotion of renewable fuels where they can be justified locally (and sometimes where economic justification is doubtful). In the long run electric vehicles will draw fuel for the transport market from gas rather than oil. In the power market, the role of gas will be determined by the local and regional mix of policy and low-carbon resources.

118 Compares to 2.9 bn toe in IEA IEO 2011.

Appendix 2: Markets for Oil in Transport

The United States

The US transport market consumed 13 mbd in 2010: nearly 15% of world petroleum supply. Over 90% of US transport fuel was used in road vehicles.¹¹⁹

The US is a prime example of how petroleum demand has been lost to the vehicle industry, which has offered efficiency through improvements in the power train, in aerodynamic design to reduce drag reduction, in substituting lighter material, in the adoption of turbocharging, in advanced transmission systems, in camless valve activation, and in improvements to accessories and tyres.

Between 1980 and 2008 fuel consumption efficiency – miles per US gallon (MPG(US)) – in US vehicles increased by over 40% for cars and nearly 50% for light trucks and sports utility vehicles (SUVs), despite a shift away from smaller to larger (and heavier) vehicles¹²⁰ and an increase in performance. Without improvements in performance and increases in weight, the fuel efficiency achieved could have been about a third higher.¹²¹ To drive 2008 distances with 1980 vehicle technology would have required 3.5–4.0 mbd more fuel, roughly 30% more than was actually consumed.

Fuel consumption improvements in the US to date have not been continuous, though technology improvements have: from 1975 to the early 1980s improvements were directed at reducing fuel consumption to meet CAFÉ standards; in the 1980s there was balance between fuel, performance and weight gains; in the 1990s technology improvements were used to improve performance and offer heavier and larger cars.¹²² These phases corresponded closely with the price increases and CAFÉ standards of the late 1970s and early 1980s, a plateau in prices and CAFÉ standards from the mid-1980s, and rising prices and tighter standards after 2005.

Direction of policy

US dependence on imports of oil and gas – then thought to be increasing – motivated the Bush administration's Energy Act of 2005. This was followed by the Independence and Security Act of 2007, which included a CAFÉ target of 35 MPG(US) (14.9 kilometres per litre (km/l)) for 2020 for all light vehicles. The CAFÉ system was changed to adjust standards for each type of vehicle according to its 'footprint' of size, and to end averaging over different sizes; however, trading credits for those exceeding the standard were permitted.

For the first time, *climate change objectives* appeared in US energy policy in the Energy Act of 2007. The policy was limited to R&D for new vehicles, fuels and carbon sequestration, and increased obligations for the use of biofuels. In the Copenhagen Accord of 2009 the Obama administration committed the US to greenhouse gas reduction objectives. The Supreme Court held in 2010 that the EPA could regulate for greenhouse gas emissions, without new legislation.

119 EIA, *Transport Energy Data Book* 30, 2011.

120 'Addiction to gasoline' can be partly explained by an addiction to junk food. Most of the shift to larger vehicles occurred after 1995, and coincided with a rapid increase in obesity and overweight in the US population. An academic study (Shanjun Li, Yanyan Liu and Junjie Zhang, 'Lose Some, Save Some: Obesity, Automobile Demand, and Gasoline Consumption in the United States', Resources for the Future RF-DP 09-33 August 2009) estimates that a 10% increase in obesity (which occurred in 1995–2006) reduces the average mpg of new vehicles demanded (through demand for larger vehicles) by 2.5%.

121 K.H. Hellman and R.M. Heavenrich (2003), *Light-Duty Automotive Technology and Fuel Economy Trends: 1975 Through 2003*, EPA420-R-03-006, April 2003.

122 Anup Bandivadekar, Kristian Bodek, Lynette Cheah, Christopher Evans, Tiffany Groode, John Heywood, Emmanuel Kasseris, Matthew Kramer and Malcolm Weiss, *On the Road in 2035: Reducing Transportation's Petroleum Consumption and GHG Emissions*, MIT Report LFEE 2008-05 RP.

In 2010 the NHTSA and the EPA proposed a *National Fuel Economy Program* with a standard of 35.5 MPG (US)¹²³ (15.1km/l) for *new cars and light trucks* by 2015 (instead of 2020).¹²⁴ This was followed in 2011 by a target of 54.5 MPG (US) (23.2 km/l) by 2025: 62 MPG(US) (26 km/l) for cars and 44 MPG (US) (19 km/l) for light trucks. This is expected to reduce oil consumption by 2.2 mbd by 2025, wiping out the growth in consumption projected in the Department of Energy's 2011 Annual Energy Outlook reference case. Some states (such as California) will set more stringent standards.

An MIT study¹²⁵ suggests cost increases of around 10% in vehicles as a result of an initiative of this scale – a switch of value from the fuel to the automobile industries.

In August 2011 the EPA and NHTSA announced a programme for reducing GHG emissions (by limits on grams per ton per mile) and increasing fuel efficiency (gallons per ton per mile), in model years 2014–18 for *heavy-duty trucks* and vehicles not covered by other CAFÉ standards. These will be followed by more stringent standards for subsequent model years – the first time heavy-duty vehicles have been brought under control.¹²⁶ Fuel saving from these model years may reach about 0.400–0.500 mbd by 2018 – more than half of the expected growth in demand in this sector to 2025.¹²⁷

The fuel economy programme will expand the market for the auto industry and has support from most US automobile manufacturers and the United Auto workers. There will be an increase in employment in the auto industries. Under the Auto Industry Financial Relief (AIFR) programme in 2008, \$36 billion of assistance was conditional, *inter alia*, on their adopting manufacturing programmes to meet competition from the more efficient foreign brands, which were on average 5% more fuel-efficient.

An MIT study¹²⁸ has shown that if all future potential efficiency improvements, realistically projected, were to be applied to fuel efficiency, there is a plausible scenario (with some growth in miles travelled and vehicle numbers) under which fuel consumption for light-duty vehicles in the US would peak around 2020, and be 26% lower in 2035 as a result of improvements in gasoline engines, transmission and some weight reduction, and significant penetration of advanced power trains (turbo gasoline, diesel, and gasoline hybrids).¹²⁹ These findings are broadly consistent with the 27% saving from the reference case assumed in the EIA 2011 variant case,¹³⁰ which projected a 6% annual tightening in CAFÉ standards after 2016.

Because of the scope for balancing efficiency gains between fuel consumption and performance or size gains, manufacturers are still developing their strategies for model development.¹³¹ There is potential for further development of the gasoline internal combustion engine: by better aerodynamics, adding gears to allow optimal speeds, improved air-conditioning and other electrical aids, tyres with low rolling resistance, deactivating cylinders (or the whole engine) to minimize fuel consumption while idling (with 'micro-hybrids' – large batteries to support ancillary equipment when the engine is not running); beyond this would be turbocharging of gasoline engines.

Rising prices and changing culture

The substitution of capital goods (efficient vehicles) for fuel is supported by price trends. After 2003 (apart from an interruption in 2009) gasoline prices moved above their long-term historical average by nearly 60% in real terms. Vehicle prices on a like-for-like basis remain close to their 1982 level in real terms.

There is some evidence of changes in the attitude to driving by consumers. Online shopping has displaced some travel. Even before the recent increases in gasoline prices the local miles travelled plateaued and fell. Federal highway administration data show that the percentage of young Americans

123 After taking account of changes to air conditioning systems to meet greenhouse gas emission standards, the May 2010 CAFÉ standard equates to 34.2 mpUSG.

124 Thomas Klier and Joshua Linn, *Corporate Average Fuel Economy Standards and the Market for New Vehicles*, Resources for the Future RFF DP 10–68 Dec 2010

125 *On the Road*.

126 EPS/NHTSA announcement and factsheet EP420-F-11-031.

127 ICCT Policy Update 14, 23 September 2011.

128 *On the Road*.

129 *Ibid.*, Figures 54 and 55.

130 Department of Energy, Energy Intelligence Agency, *Annual Energy Outlook 2011*.

131 Soren Anderson, Ian Parry, James M. Sallee and Carolyn Fischer, *Automobile Fuel Economy Standards*, Resources for the Future, RFF 10-45, October 2010.

without driving licences has increased. Surveys by the Frontier group report that young Americans are making more use of public transport, bicycles, walking. There is a University of Michigan study showing similar trends in other developed countries.¹³²

Alternative fuel vehicles: CNG, electricity, hydrogen, E85 (flex fuel)

Alternative fuel vehicles benefit from a long history of federal aid by way of tax breaks, subsidized R&D, mandatory shares of government vehicle and public transport vehicle fleets, and tax credits for certain infrastructure.¹³³

Alternative fuel vehicles in the US increased from 0.15% of the total fleet in 1995 to 0.4% in 2009. Nearly two-thirds of these were flex-fuel vehicles (capable of using 85% ethanol). Blending of ethanol into Gasohol and E85 has removed 0.8 mbd of petroleum demand.

Under the new CAFÉ system, the MPG(US) of an alternative fuel vehicle (AV) is discounted to 15% for compliance with the CAFÉ standard, creating a tradable credit, a cost penalty to the purchaser and a benefit to the alternative fuel vehicle manufacturer.

Already in model year 2011 more than 50 models of flex-fuel vehicles were on offer in the US, as well as 30 different models of hybrid electric vehicles. Single (essentially pilot) models of CNG, hydrogen fuel cell and all-electric vehicles were available.¹³⁴ However, growth depends on further cost reductions or policy mandates. The MIT study quoted above estimated that at gasoline prices of \$2.5 per gallon (in 2007 dollars), only hybrid vehicles would recover their higher cost from fuel savings. At \$5 per gallon however, diesel, turbo hybrid, turbo gasoline, plug-in hybrids and fuel cells (but not plug-in battery electrics) would all recover their full costs. More recent studies produce a variety of estimates.

Summary: The transport market for energy in the US

Current policies do not tip the transport market away from petroleum, but they shrink it. Interpretation of the MIT studies and the EIA scenarios for extended CAFÉ standards suggests that the market for petroleum fuels in US transport would change from 2009 to 2035, under current policies; petroleum consumption would increase (mainly diesel) in the reference case by 1.6 mbd, but fall by about 1.5 mbd in the case with extended standards – a switch of about 3 mbd (see Table 11).

Table 11: Changes in fuels for US transport, 2009–35 (mbd)

Extended CAFÉ standards versus current policies	Reference	Continued CAFÉ
Distillate (diesel)	1.3	1.9
Gasoline including 15% M85	0.0	-3.2
Total petroleum	1.6	-1.5
Ethanol	0.5	0.7
Total transport	2.2	-0.7
Other energy	0.1	0.1

Source: DOE Annual Energy Outlook, 2011.

To reduce petroleum use further to the ‘450ppm’ constraint for greenhouse gases, the transport sector would need to reduce petroleum consumption by 4 mbd, instead of increasing as in the case above by about 2 mbd. In very broad terms, about two-thirds of this change could result if all the foreseen improvements in vehicle efficiency were applied to fuel economy, as suggested in the MIT study cited above. The rest would need to come from non-petroleum sources and/or reduction in transport use.

132 Michael Skapinker, ‘Car culture is taking a back seat in modern life’, *Financial Times*, 26 April 2012.

133 See US Dept. of Energy, Alternative Fuels and Advanced Vehicles Data Center, <http://www.afdc.energy.gov/afdc/laws/eiea> 2008.

134 DOE *Transport Energy Data Book 30*, 2011.

China

In 2010, 3.1 mbd of oil was consumed in the transport sectors of China.¹³⁵ GDP (PPP) per capita in China was 16% of the US figure. Car ownership per capita in China was just under 5% of that in the US in 2007, but increased by an average of 25% annually to 2010, making China the largest vehicle market in the world, helped – as part of the economic stimulus packages – by subsidies and incentives for smaller cars (70% of the total) and for replacing inefficient agricultural vehicles.

Varying projections

The rapid growth in car ownership among Chinese with higher incomes is the basis of very widely varying predictions of rapid increases in vehicle ownership and oil consumption.¹³⁶ Projections for the growth of vehicle numbers in China up to double the projections of agencies such as the IEA or EIA are suggested by comparison with countries where vehicle numbers increased rapidly after income per head reached the level of China's today.¹³⁷

EIA and WEO reference case projections for China,¹³⁸ on policies current at mid-2011 (including the 12th Five-Year Programme but not the 2011 auto efficiency standards¹³⁹), are very similar. Uncertainties about economic growth rates and energy prices overhang all these. Both agencies project an increase of 6–7 mbd in Chinese demand for liquids in transport by 2030, including 0.2–0.3 mbd biofuels. In the EIA projections, this accounts for nearly 40% of the increase in world demand for liquids in transport. This would bring Chinese consumption to nearly double that of the EU (compared with half today). The proportion of total oil consumption taken by transport would rise from just over 40% to just under 70% (like the US), implying that oil had been squeezed out of growth in other sectors.

Standards

China, unlike the developed economies, is undergoing rapid urbanization and rapid deterioration of urban air quality, though vehicles are subject to EU Auto Oil III standards. As well as favouring smaller cars the government sees limitation of vehicle use and the development of electric vehicles of various kinds (including electric cycles) as the key to improving urban air quality.

Efficiency standards for vehicle manufacture in China were phased in from 2005, based on standards for each weight class. All types of electric vehicles count with a premium.

Phases 1 and 2 of the programme reduced average fuel consumption from 9.11 litres per 100 kilometres (l/100km) (25.8 MPG(US)) to 8.06 l/100km (29.2 MPG(US)), a reduction of 8.8%. The new (2011) target for 2020 is an average of 5.0 l/100km (47 MPG(US)), a reduction of 45 % in the whole fleet. If this were achieved, liquid fuel consumption in 2020 would be 3.5–4 mbd lower than the 'current policies' projections or when the last vehicles produced under earlier standards are scrapped. In reality, the impact of the efficiency-related factors on vehicle ownership and use is uncertain. Accenture estimates a loss of oil demand by 2020 of about half this number: 12% via internal combustion engines, 4% via cellulosic ethanol, 4% via electric vehicles.¹⁴⁰

Some Chinese cities, such as Beijing, not only ban car circulation for one day a week, but also limit car sales. In Beijing, people will have to join the lottery to gain permission to buy a car. If this continues and spreads to other major cities, it will slow the car fleet growth rate.

135 WEO 2011 Appendix 1.

136 Michael Wang, Hong Huo, Larry Johnson and D. He, *Projection of Chinese Motor Vehicle Growth, Oil Demand, and CO2 Emissions Through 2050*, Argonne National Laboratory, 2006.

137 Yunshi Wang, Jacob Teter 1, Daniel Sperling, 'China's soaring vehicle population: Even greater than forecasted?', *Energy Policy* 39 (2011).

138 IEA and EIA projections (reference cases) for China 2035 use the same (UN-based) population projections for a 0.3% growth to 2035 (higher than Russia, Europe and Japan, but lower than the US, Middle East, Europe, and most developing countries). GDP projections (drawing on IMF projections) are similar at \$33 trillion (\$2005, PPP). Both forecasts assume that Chinese GDP growth will fall to around 4% after 2020, giving an average growth to 2035 of 5.8%. Compared to this, transport demand is projected in the reference cases to grow at 4.8%. Alternative EIO scenarios deal with different global growth rates and oil prices and WEO presents different severities of climate policies. (Neither agency publishes a variant specifically for different Chinese growth rates.)

139 Described in IEO 2011, pp. 126–27.

140 Accenture, *The United States and China: The Race to Disruptive Transport Technologies*, 2010.

Alternative fuels

For the longer term, the government is reinforcing competition from alternate fuel vehicles, named as a strategic industry in the 12th Five-Year Programme (2011–15) with a target of 30% of transport fuels by 2030. Electric vehicles, including plug-in electric vehicles (PEVs) are subsidized; the government plans to invest \$15 billion over ten years, including setting up a charging network, and ten cities are to receive various subsidies to support pilot schemes.

The Chinese market and industrial base is large enough to permit a variety of technologies to be tested against each other in the market place, though both the automobile and battery industries need consolidation. Battery developments are a key. China has a large and diverse battery industry and dominates world supplies of lithium, so lithium ion development is a priority. Since 2001, China has overtaken the US in patents for electric vehicles and related technologies, but relies on bought-in or joint-venture technologies for advanced developments.

China is unique in containing all the elements for an electric-based transport supply chain: the road system, charging infrastructure, vehicles and battery manufacture, lithium, coal and nuclear power. All are capable of being co-oriented by government as well as by competition (because the market and manufacturing base is so large).

Chinese auto and battery manufacturers are already export-oriented. Taking all these factors together, it seems likely that the transport energy systems that evolve in China will have effects far beyond Chinese territory.

China is experimenting with coal-derived liquids including gasoline, diesel and methanol. Methanol blending has been tried in many provinces. Given the cost differential between gasoline and methanol and lack of regulatory enforcement, illegal blending is widespread.

Modal choices

The 12th Five-Year Programme (2011–15) aims to make over 90% of villages accessible by vehicles by 2015, though growth in transport demand may be slowed by policies to make the logistics of the economy more efficient. The 12th Five-Year Programme aims to spread the burden of urbanization away from very large cities by improving highway and rail links (by 2020 China will have the world's largest high-speed rail network), promoting the development of (relatively) smaller new towns, and building subways in 20 cities. The concept appears to be that transport in cities will be provided by a higher proportion of walking, cycling (including electric cycles) and public transport than in the US, while long-distance rail, alongside buses and trucks, will reach into the hinterland.

Europe

In 2008 the EU consumed 6.2 mbd of petroleum¹⁴¹ for transport – half of EU total petroleum consumption and 7% of world petroleum supply. Some 70–75%¹⁴² (4.6–5 mbd) is for road transport, equivalent to around 40% of EU petroleum demand.

European gasoline and diesel demand in 2008 was about a third less (3 mbd) than it would have been with an equivalent US vehicle fleet, driven as Americans drive. Around 15% of passenger transport in the EU is by bus, rail or tram,¹⁴³ compared with around 5% in the US.

There are many reasons for the gap:

- Lower incomes in Europe than the US lead to fewer vehicles per person, smaller vehicles and fewer miles driven.
- Higher fuel prices (due to higher taxes) in Europe – typically double US prices – lead to less driving and a preference for efficient vehicles rather than more fuel.
- On a like-for-like basis, vehicle prices in Europe have been steady or declined while fuel prices have doubled in the last two decades, compared with a 60% increase in the US.

141 WEO, 2010.

142 Ibid: extrapolated from data for CO₂ emissions.

143 Martin Lowson, *Energy Use and Sustainability Of Transport Systems*, Advanced Transport Group, University of Bristol.

Fuel efficiency

Comparisons of fuel efficiency are difficult because of the lack of Europe-wide statistics, but it appears that over the European Economic Area (EEA) group of countries,¹⁴⁴ fuel efficiency probably improved by up to 20% between 1985 and 2005.¹⁴⁵ The improvement continued after 1990, while improvements in US vehicle efficiency were absorbed by increases in weight and performance, and Japanese fuel efficiency fell.

European vehicle manufacturers have continually improved the energy efficiency of their vehicles. However, as in the US, they have used part of their fuel efficiency gains to produce larger, heavier and higher-performance vehicles. In negotiations with the European Commission for the Voluntary Agreements of 1997, the European Automobile Manufacturers Association (ACEA) stated that from 1983 to 1997 actual fuel efficiency had improved by 28%, but 20% had been absorbed in increases in weight, performance and emission control equipment. ACEA suggested that in future half of the increases in efficiency would be used to reduce fuel consumption.¹⁴⁶

In Europe there was also a tax-driven shift from gasoline to diesel, which now supplies just over half the energy used in EU road transport. A third of private cars are now diesel-powered, and the proportion is increasing.

Policy direction

The momentum of policy has been different in Europe from that in the US. In Europe, fuel consumption in transport has been restricted by increasing fuel duties,¹⁴⁷ which were already high in the 1970s. Many countries also increased excise taxes on large cars. There were no EU targets for fuel efficiency, but in 1996 the European Commission began to negotiate CO₂ emission targets – which correlate with fuel efficiency – in voluntary agreements with ACEA, and the equivalent Japanese and Korean associations.¹⁴⁸ These targets are applied to the whole industry; the association negotiates how individual members are to meet them. The targets have not been met in recent years and the commission has established mandatory regulations for passenger cars of 95 grams of carbon dioxide per kilometre (g CO₂/km) from 2020, and for light commercial vehicles of 135g CO₂/km from 2020.

The current (2011) White Paper¹⁴⁹ (see below) aims to reduce GHG emissions to 20% below their 2008 level by 2030 and 60% below their 1990 level by 2050. There is also unfinished business in creating a single European market for air, road, water and rail transport, including infrastructure development, safety and vehicle licensing and taxation.

The 2011 EU White Paper on transport: peak demand for oil

The Impact Assessment¹⁵⁰ accompanying the White Paper translates its objectives into four scenarios for energy use in the transport sector. In Scenario 1, with the least change in policy, by 2030 demand for passenger transport increases by 34% and for freight transport by 38%, while energy demand for transport increases by only 5% and the demand for oil falls very slightly.¹⁵¹ Biofuels would replace fossil fuels for 10% of actual, 7–8% (0.7–0.8 mbd) of potential energy demand in transport. (It is likely that biofuels targets will be reduced because of increased criticism of their effect on CO₂ emissions, food supply and welfare in exporting countries.)

144 The EU plus Norway, Iceland and Lichtenstein.

145 Lee Schipper, 'Automobile Fuel: Economy and CO₂ Emissions in Industrialized Countries: Troubling Trends through 2005/6', EMBARQ, the World Resources Institute Center for Sustainable Transport 2007, Figure 1.

146 Sarah Keay-Bright, 'A critical analysis of the voluntary fuel economy agreements, established between the automobile industry and the European Commission, with regard for their capacity to protect the environment', Draft paper for ECPR, Joint session, Grenoble, 6–11 April 2001, Panel No. 1: New Environmental Policy Instruments.

147 And dedicated to highway maintenance, unlike in Europe, where duties are paid into general government revenue.

148 Including European plants manufacturing US brands.

149 Com 2011 144, 28.3.2011.

150 Commission Staff Working Paper SEC(2011)358 final.

151 White paper, para 51.

Under this policy, oil demand in the transport sector (road, air, and other modes) would reach a rough plateau between now and 2020 and would then begin a slow decline. By implication¹⁵² about 2–2.5 mbd of oil demand in transport would be replaced by using more efficient capital equipment, hybrid cars and management systems. About half of this replacement would be in passenger cars.

In the three aggressive policy scenarios which use varying combinations of standards – mainly for CO₂ – and taxation – mainly on carbon – more aggressive improvements in vehicle technology and penetration by electric vehicles would further reduce oil demand by around 1.7–2.3 mbd by 2035 and by a further 2.5 mbd by 2050.

The policy option focusing most on efficiency standards also creates employment in the vehicle manufacturing sector and supports the role of the European automotive industry in developing technologies for the future and for export.

Japan

Japan's transport system consumed 1.4 mbd of oil in 2008, about 30% of its oil consumption (unlike the US where nearly 70% of oil is consumed in transport). The fuel economy of new cars has steadily improved and by 2005 was about 30% below average fuel economy of new cars in the US, and was not much below 1980 in Japan (improvements in efficiency had been absorbed by larger cars).¹⁵³ Comparisons are fraught with data difficulties. Compared to the US, per capita, Japan has 85% of the GDP, more than ten times the density of population, half the number of cars, and a third of the energy consumption in road transport.¹⁵⁴

Fuel efficiency standards, based on weight, have been in force since 1979. Amendments follow the 'top runner' to incorporate the best achievement of the preceding period into the minimum for the next regulatory period (hybrid electric vehicles are now the trend-setter for the next period). A consultation paper (August 2011) proposes a 2020 minimum of 20.1 km/l (47.3 MPG(US)), a reduction of 24%, with a reduction of approximately 2% per year in fuel consumption – a lower rate than envisaged in the US for 2015 or the EU for 2020. A 24% reduction of fuel consumption achieved by this route would translate into roughly 0.3 mbd by 2020.

152 These figures are inferred from the document, but not contained in it.

153 Schipper, 'Automobile Fuel'.

154 'Energy Efficiency and Urban Development (the Building Sector and the Transport Sector); CCICED Policy Research Report, 2009.

Appendix 3: Gas in Key Power Markets

United States

Overview with mid-2011 policies

The gas and power industries in the US are organized in the private sector, with regulations to ensure open access to pipelines and price controls on monopoly situations. There are extensive interstate pipeline networks and (less extensive) electricity grids with regional pooling arrangements. Gas prices are set through continuous trading at the 'Henry Hub' distribution point.

In 2009, the power sector took 32% of gas supplies, and supplied 19% of the primary fuels used in the power sector. Primary fuel use for power generation would increase slowly by 17% to 2030 – more than the forecast increase in energy demand but less than the growth in GDP, reflecting the continuing electrification of the US economy. Under current policies the proportion of gas used in the power sector would barely change to 2030.

Table 12: Share of primary fuels in energy demand for power generation in US under current policies, 2009–30 (%)

	2009	2030	Change 2009–30
Coal	49	46	-3
Nuclear and hydro	27	26	-1
Gas	19	18	-1
Renewables	4	10	+6
Oil	1	0	-1

Source: International Energy Agency, WEO 2011, Current Policies.
Rounded numbers.

With cheap shale gas, and all coal stations requiring retrofitting to meet expected new GHG emissions standards, these EIA cases show that gas demand for power generation in the US in 2035 could be 68% above 2009 levels, compared with a worst case for gas of 24% below 2009 levels.

Policies

The EIA 2011 reference case projects a slow growth in national greenhouse gas (GHG) emissions (after falls in 2008 and 2009), as GHG emissions standards in vehicles are aggressive tightened, until by 2027 vehicle emissions reach 2005 levels. The electricity sector remains the main emitter: 40% of GHG, ahead of transport (34–33%). These projections assume no federal cap-and-trade controls or carbon taxes.¹⁵⁵

International trade

The US is moving towards self-sufficiency in electricity generation. Net electricity imports from Mexico and Canada shrink from 0.12 quadrillion British thermal units (Btu) (3.3 bcm or 120 bcf) to 0.05 quadrillion Btu (1.4 bcm or 50 bcf) in the 2035 reference case – less than 1% of consumption use. In

¹⁵⁵ These and subsequent numbers in this section for the US are taken from DOE Energy Information Agency, *Annual Energy Outlook 2011*.

the reference case, natural gas net imports fall from 2.73 quadrillion Btu (76 bcm or 2,703 bcf) to 0.35 quadrillion Btu (9.7 bcm or 350 bcf). It is now widely perceived that the US may be able to export gas. The Chenière project is converting from import to export of LNG. Exports are favoured by producers because of higher prices outside the US but opposed by consumers such as the chemical industry, for which gas is an important feedstock and cheap gas would be a competitive advantage internationally. Small exports of coal continue. Coal and gas prices are largely determined in the US. Higher gas production (from shale gas) would make gas more competitive. It is questionable whether marginal imports (or exports) of natural gas from the international LNG market would set internal prices.

Uncertainties

These trends are far from certain. The uncertainties arise from internal US factors.

Renewables support

The growth in renewables is driven mainly by policies in 30 states which favour renewables through Renewable Portfolio Standards (RPS), requiring 20–40% generation from renewables by 2017–30. About half the growth in renewables is from biomass, co-generation at biofuels plants and co-firing of biomass in coal plants. The balance is from wind. Federal tax credits for renewables expire in 2015. Renewables use will be increased if the credits are extended.

The National Electricity Reliability Council (NERC) has called for back-up capacity and operating protocols to accommodate intermittency in regions where wind is a major source of supply (wind may be de-rated to 8–14% of capacity for peak management requirements). The NERC estimates that between 2012 and 2018 the capacity of the power grid to deal with peak demands or outages could also be stressed by the de-rating of a large number of coal-fuelled generators.

Future greenhouse gas emission controls

There are currently no federal GHG emissions controls or taxes on the power sector, but the state of California, and 10 northeastern states (in the Regional Greenhouse Gas Initiative) have announced emission control programmes with cap and trade.

Electricity distribution, transmission and generation are in the hands of investor-owned companies. There is no US-wide grid. Federal and state regulations provide common carrier availability on transmission line and competition between generators within regions. There are local and national power pools.

Higher coal costs

Proposed regulations on water use and disposal are likely to force closure of some mines and coal-fired generating plants. Regulations on sulphur dioxide and NO_x removal, requiring all coal plants to be fitted with scrubbers, and retrofitting to remove mercury and other toxic elements from flue gas, could at the extreme force the closure of 20% of the coal generating plants, with retrofits or replacement being inhibited by the regulatory uncertainty.

Gas price uncertainty

Natural gas is seen as the main beneficiary of reducing coal use, since renewables are already stretched with the support of strong mandates. However, if renewable tax credits are extended beyond 2015, and/or if energy efficiency standards are renewed and strengthened so as to reduce electricity demand, the gains to natural gas would be reduced or reversed – at least in the medium term. In the IEA scenario input prices favour coal over gas: wellhead prices of gas increase 2% annually above coalmine-mouth prices (which are almost flat). Wholesale electricity prices fall slightly in real terms, as generating costs fall because of increased utilization rates at coal plants and the falling share of nuclear.¹⁵⁶ There is some

156 US Energy Information Agency, *Annual Energy Outlook 2011*.

rebound effect as lower demand leads to lower natural gas prices (but see discussion of international trade below).

A combination of severe retrofitting of all coal plants and low gas prices resulting from high shale gas availability could increase natural gas use in the electricity sector by up to 35% compared with the reference case.¹⁵⁷

Competition from use-avoidance

Federal and state governments impose energy efficiency standards on a variety of electricity-using appliances and equipment, and on buildings. Compared with 2010 technology, these standards are estimated by the EIA to save a total of 27 quadrillion Btu (750 bcm or 27,000 bcf), equivalent to a year's consumption of natural gas in 2035. About 60% of these savings are incorporated in the EIA reference (current policies) case. These result from policy, not prices: electricity prices fall very slightly.

Expanding the efficiency standards could avoid a further 19 quadrillion Btu (530 bcm or 19,000 bcf) of demand. The cost to consumers (the market to providers) for energy-saving technology in buildings is estimated at \$14 billion annually, plus \$1 billion of additional tax credits. This indicates the market opportunity for businesses which lower electricity demand. Benefits to consumers are projected at \$29 billion per year from energy purchases avoided and for the effect of lower demand on energy prices.¹⁵⁸

Gas as the balancing fuel for power

The market for gas for power is hemmed in between policies which promote renewables and those which penalize or promote coal or nuclear. A combination of renewables and coal has political attractions. There is also uncertainty on the supply side and the combination of this with demand uncertainty makes for an uncertain outlook for prices and volumes. EIA cases show that gas demand for power generation in the US in 2035 could be 68% above 2009 levels, compared to a worst case for gas of 24% below 2009 levels. The effects of lower electricity demand (5% lower in the EIA 'extended policies' case for 2035, compared with the reference) will most affect the demand for gas. Renewable capacity would have been front-loaded by tax credits, and supply would receive priority in many state mandates. Renewables in one form or another would gain a 4% share of the electricity generating market from gas, with a possible absolute fall in demand for gas for electricity generation between 2020 and 2025.

A low-cost nuclear scenario increases the electricity demand by 6%, compared with the reference, and increases the nuclear share by 2% at the expense of gas.

The result of all these uncertainties is that there is more variation in the outlook for the gas market in power than for any other sector of the gas market.¹⁵⁹

The European Union

The power sector in 2009 accounted for about a third of the gas market in the EU. Under current policies, this is set to rise to 37% as energy efficiency measures reduce growth in the direct use of gas in building and industry.¹⁶⁰ Demand for electricity is projected to grow slightly faster than demand for primary energy, but significantly more slowly than GDP, reflecting the continuing electrification of the economy with reducing energy intensity.

For the power sector, gas will become a more important source of primary fuel, under current policies, while renewables gain most, at the expense of coal, oil and nuclear. Table 13 shows the IEA WEO 2011 projections under 'current policies'.

157 Ibid.

158 Ibid.

159 National Petroleum Council: Prudent Development; National petroleum Council 2011 Figure ES7.

160 WEO 2011. There are no projections from EU sources since the 2009 update of 'Energy Trends', prepared by the Technical University of Athens, That projection showed a falling share for gas and other sources as a result of very large increases in renewables.

Table 13: Share of primary fuel demand by the power sector, 2009–30 (%)

	2009	2030	Change 2009–30
Nuclear/hydro	37	30	-8
Renewables	9	20	+11
Gas	20	26	+6
Oil	4	1	-3
Coal	30	24	-6

Source: International Energy Agency WEO 2011 Current policies.
Rounded numbers: share of primary energy demand.

Policies

The place of gas in the EU power sector is driven by policies, and uncertainty about policies is great. Energy policy in the EU is a Rubik's Cube, manipulated by many hands: the 27 member governments with national competence, and the EU institutions with Union-wide competence – the European Council of Heads of Governments, the European Commission and the European Parliament. The balance of power between these shifts, politically and legally, as more subjects are placed, by treaty, under qualified majority voting in the Council and co-decision between the Council and parliament. Only since the Lisbon Agreement of 2006 have the European institutions had competence in energy policy: previously their interventions were based mainly on environmental, competition and single-market provisions of earlier treaties. Constitutional changes are not over.

EU energy policy is bound together by common political threads: economic competitiveness, climate management and energy security. These are embodied in 2010 legislation embodying '20-20-20' targets approved in 2009: by 2020, compared with 1990, to reduce greenhouse gas emissions by 20%, supply 20% of energy consumption from renewables, and reduce primary energy consumption by 20% through energy efficiency (directive proposed 2011).

Completion of the single market

'Natural gas will continue, provided its supply is secure, to play a key role in the EU's energy mix in the coming decades and will gain importance as the back-up fuel for variable electricity generation. In the medium term depleting indigenous conventional natural gas resources call for additional, diversified imports. Gas networks face additional flexibility requirements in the system, the need for bi-directional pipelines, enhanced storage capacities and flexible supply, including liquefied (LNG) and compressed natural gas (CNG).'

Commission's Proposal on Guidelines for a Trans-European Energy Infrastructure, COM 2011 658

This proposal is the Commission's first real step towards a substantive European energy policy based on its enhanced powers under the Lisbon Treaty. It complements and reinforces the energy security policies of the Commission. It goes further than the Directives on Gas and Electricity of 2009, which were aimed at removing commercial restrictions, providing open access to pipelines, and separating by various degrees the management of pipelines and grids from the supply and distribution functions, and promoting competition.

An unresolved economic and competitiveness question is the survival of the pricing system for most imports from Russia, Norway and the Netherlands, which is linked to changes to oil prices. Oil is no longer a significant competitor for gas in the power markets. Buyers under long-term contracts face competition from short-term supplies, typically of imported LNG, at the various gas 'hubs' such as the UK National Balancing Point. Some contracts allow these prices to be factored in for a portion of the contract. The present (2012) disparities between US prices of around \$5/mmbtu, European prices of around \$10/mmbtu and Asian prices of around \$15/mmbtu will be difficult to sustain.

There has been a trend for producing companies to contract a portion of their supplies to their own subsidiaries, in order to preserve some market flexibility. It is possible that we may see the development of a hybrid system, in which part of the trade flows under hub prices, and part under prices indexed to oil, coal or some composite. The competitiveness of renewables will be affected by gas prices. On the one hand, the availability of cheap gas as a continuous fuel supply raises the hurdle for competition from renewables; on the other hand, since renewables require back-up from gas for interruptions in supply, the variable cost of back-up will be reduced.

As a result of the development of US shale gas, investments in African and Middle East supplies, and weak demand, these ‘hub’ prices have in recent years been significantly below oil-related gas prices.¹⁶¹ Lower prices could lead to more gas being used, but probably not more Russian gas, owing to the cost and difficulty of expanding Russian gas supply.

Emissions controls

The EU has two sets of commitments to reducing greenhouse gases:

- The Kyoto Protocol: the EU has committed to reducing its greenhouse gas emissions to 8% below 1990 levels by 2008–12. Partly as a result of recession, emissions in 2010 were 15.5% below 1990 (compared to an increase in GDP of 41%)¹⁶² so that the target is likely to be overshoot. At the December 2011 Climate Change Conference in Durban, the Kyoto parties agreed to negotiate an extension to the Kyoto Protocol to provide targets beyond 2012 when the present commitments end.
- The first element in the ‘20-20-20’ policy package, agreed in 2009 and legislated in 2010, is a more severe commitment. This imposes a 20% reduction by 2020 in greenhouse gas emissions from the 1990 baseline. The EU is prepared to increase this to 30% as long as legally binding commitments are made by all parties. The Durban conference of 2011 opened a process for negotiating (by 2015) a new treaty, legally binding from 2020 on all parties, including the US and developing countries, which escaped commitments at Kyoto. Some of these new commitments will be met by policies applied outside the gas and power sector, to reduce the demand for energy and electricity, but further policies to bias the generators further against fossil fuels are inevitable.

There is uncertainty about what the new more severe policies will be, but inevitably the main thrust will be to reduce allowances under the emissions cap-and-trade system (ETS): power stations, which emit nearly 60% of EU GHGs, need allowances to emit greenhouse gases (notably CO₂). From 2013 allowances will be set on an EU basis (formerly they were allocated to member states, which then allocated them to sectors and ultimately to individual power plants). Allowances are tradable directly through exchanges, which generate a ‘carbon price’. The system has evolved since it started in 2005. As more businesses are brought into the system, the cap on allowances has been tightened, and a greater proportion of allowances has been auctioned. Further tightening is unavoidable.

Oil is already a very small component in the mix of fuels for power in most countries. Coal burnt in power stations emits 1.7–1.8 times as much CO₂ as natural gas per unit of energy, so that the adjustment will fall largely on coal in those countries where it will still have significant use under current policies: Germany, Poland, and the UK. Countries which have already eliminated or reduced the use of coal and oil, and which have determined to close nuclear plants without replacement, can be expected to force even higher levels of renewables and more severe policies to reduce the demand for electricity, so that the demand for gas in the power sector in Europe could plateau, or fall, by 2030.

161 Jonathan Stern and Howard Rogers, ‘The Transition to Hub-based Gas Pricing in Continental Europe’, OIES NG 49, 2011.

162 Report from the Commission to the European Parliament and the Council COM9(2011)624, 7 October 2011.

Renewables obligation

The second '20' in the 2009 energy policy package is that by 2020, 20% of EU gross final energy consumption should be met by renewables.¹⁶³ The renewables target is varied for different countries to take account of their actual and potential renewables capacity. The targets are for the UK: 15%, for Poland: 15%, for Germany: 18%, for Spain: 20% and for France: 23%. Within those targets, each country is mandated to use 10% of renewables in its transport sector. Recognition of biofuels or renewables imported from outside the EU is subject to restrictions about competition with food production and social conditions. Outside the transport sector, the main burden of the renewables obligation will fall on the power sector.

GHG emissions are regulated by the 20% cap on emissions, and by the ETS allowances. The renewables obligations will not change the limits on GHG emissions from the power sector, but will make it more expensive to meet them, privileging more expensive, subsidized and intermittent renewable supplies over gas, and driving down the price of carbon in the ETS allowance scheme (because it will reduce the demand for allowances) The renewables policy is also supposed to contribute to security of supply, rural development and technological innovation. Whether these contributions are worth the cost will inevitably be scrutinized as circumstances change and results are more evident.

The renewables targets will increase the costs and complexity of power generation – at least in the short and medium term until (and unless) renewable costs come down to levels where they do not need policy support. Usually, as in the UK, there is a facility to minimize additional costs through trading certificates of renewable supply so that a generator can fulfil its obligations by buying certificates from the lowest-cost renewables producer. Priority access to the power grid is guaranteed, but the price of certificates varies with the wholesale price of electricity and the supply and demand for renewable certificates.

Because many renewable supplies are intermittent (wind, solar), situations can arise when there is no demand for renewables and they are paid compensation. Intermittency also means that the systems require back-up, not only of generating capacity but of the primary fuels needed to use that capacity during periods of peak demand coinciding with low renewables supply. This is likely to mean more gas-fired generating capacity and gas storage. In many countries, the use of renewables requires price support, either through feed-in tariffs or through price support. Typically these additional costs are eventually recovered from consumers.

Renewables policies in the EU cannot be regarded as stable. Already in the UK, the Netherlands, Spain, and Scandinavia the support system has changed to reduce feed-in tariffs for domestic wind and solar generators. As renewables' costs come down there will be further changes in support systems. The cost and the problems of reliability with intermittent supplies will have implications for the gas market either through requiring gas storage or through volatile demands placed on responses to fluctuations in renewables supply. Some investors are bundling together investments in gas production and distribution and renewables supply to provide some diversification of the risks created by the renewables' obligations for each section of the supply chain.

Energy efficiency

The third '20' in the 2009 energy policy package is achievement of a 20% reduction in primary energy consumption by 2020. On current trends this will not be achieved, even if the targets for GHG emissions and renewable energy are met,¹⁶⁴ so the Directive proposes additional measures. Such a directive was proposed in 2011 and is in the legislative process.¹⁶⁵ It will require member states to set national efficiency targets which will not necessarily be binding. However, if in its 2014 review the EU seems unlikely to meet its 20% target, the Commission will propose mandatory targets. The main scope of the targets is buildings, with renovation of publicly owned buildings and public-sector procurement receiving strict targets. The targets should be set as absolute numbers but many of the measures will ask for 'intensities' of energy use per unit of output (for the industrial sector). Efficiency targets in the power sector will promote combined

163 Directive 2009/28/EC of 23 April 2009.

164 Commission staff working paper, 'Impact assessment on proposed energy efficiency directive', E(2011), 22 June 2011.

165 Proposal for a directive on energy efficiency. COM (2011 370) 22 June 2011.

heat and power generation and permits for new generation will be biased towards co-generation. ‘Smart meters’ for consumers will become obligatory.

If the efficiency improvements are achieved, there will be a reduction in greenhouse gas emissions and the price of emission allowances under the ETS will fall, reducing the bias against carbon-heavy fuels in the mix of primary fuels used to generate electricity. The scale and effectiveness of the efficiency measures therefore create uncertainty about the fuel mix as well as about the level of power demand.

Energy security

In 2009 the EU 27 imported 54% of its energy consumption. Imports supply a higher percentage of certain energy sources: 84% of the oil, 64% of the natural gas and 62% of the coal. Excluding imports from Norway, the EU imported about half of its gas consumption, and about half of that was from Russia. Russia was an important supplier to Germany, Poland, and Italy and to countries in Eastern Europe and the Balkans. For Western Europe, LNG or pipelines from North Africa were the main sources of supply. The diversity of dependence is shown in Table 14.

Table 14: 2009 gas imports as proportion of consumption (%)

	Russia	All other countries except Norway
EU 27	24	49
Germany	46	52
Poland	61	75
Italy	31	79
France	8	58
Spain	0	90
UK	0	11

Source: Eurostat.

About 90% of the imports from Russia to Germany passed through Ukraine. A series of disputes between Gazprom and the Ukrainian gas operators since 2006 led to an interruption of supplies to the Ukraine in January 2009. As a result exports to the EU and Moldova were cut for over two weeks.¹⁶⁶ In some Balkan countries there were absolute shortages of gas. This realized European fears about the security of Russian supplies and demonstrated the inadequacy of both the European Commission and the Energy Charter Treaty in dealing with the problem. Finance for restarting the pipeline system was provided by the European gas companies. The episode gave political emphasis to measures intended to improve gas security:

- Russia and the EU have agreed to set up an ‘early warning system’ to notify each other, and consult, if supplies of gas, oil or electricity to the EU are disrupted or likely to be inadequate.
- In 2010 the EU adopted a Regulation on Gas Security. Member states designate authorities to manage gas security, exchange information and plans through the European Network System Operators. Each country should show that it could maintain peak supplies in the event of a 30-day disruption of the largest infrastructure under winter conditions (this does not apply to renewable supplies at their present levels). Regional consultation and cooperation are encouraged.
- Money for infrastructure: In its Multi-annual Financial Framework, June 2011, the Commission agreed €9 billion (out of a total infrastructure budget of €40 billion), for improving trans-European

¹⁶⁶ Simon Pirani, Jonathan Stern and Katja Yafimava, ‘The Russo-Ukrainian Gas Dispute of January 2009: A Comprehensive Assessment’, OIES, 2009.

infrastructure, increasing the flexibility of the system to handle disruptions. It has also proposed a 'Project Bond Initiative' to attract equity investment into energy infrastructure projects. The ratings of energy project bonds would be improved by subordinating EIB loans and/or guaranteeing private-sector investors, with the EU itself covering the EIB's higher risk.

- Renewed efforts by the EU to promote the Nabucco pipeline, which would enable Europe to gain access to Caspian natural gas without passing through the Russian pipeline system. The pipeline would supply Central and Southeastern Europe. There have been three difficulties, some of which may slowly be diminishing:
 - Higher cost;
 - Inadequate reserves and lack of commitment from Azerbaijani producers;
 - Cost and lack of commitment (and trans-Caspian legal problems) for access to gas from Kazakhstan or Turkmenistan.

Russia has a permanent and structural interest in preserving access to the European market, which takes 80% of its gas exports and where competition is increasing owing to the encroachment of new gas supplies from lower-priced markets. From the Russian side, Gazprom, with German gas companies, has constructed the 'Nordstream' line which could divert about half the current level of imports through Ukraine. A 'South Stream' line across the Black Sea could divert most of the rest, albeit at higher cost. There are several other proposals for a southern pipeline.

There is therefore the likelihood in the longer run of a surplus of pipeline capacity and diversity of routes: a satisfactory situation for both exporters and importers (but not for pipeline investors or transit countries). Meanwhile, one new pipeline project (or a raft of new LNG projects) is likely to be needed by 2020 to avoid a decline in the 'headroom' of supply capacity over projected peak demand.¹⁶⁷ That pipeline will pre-empt and delay others, so that competition between project proposals is intense.

Europeanization of external energy negotiations

The 1996 Trans-European Networks for Energy (TENS) initiative carried no money beyond what was needed for feasibility studies, and accumulated a very large list of 'projects of priority'. In 2011 the Commission tried to push for resolution of planning and international differences on five key energy projects, with one success, one failure, and three works in progress.¹⁶⁸

Because member states have a parallel competence in external affairs, there are many bilateral agreements in energy, mainly concerned with investment protection or access to infrastructure. In 2011 the Commission proposed that all such agreements should be submitted to the Commission to validate their consistency with Community law, thus strengthening the negotiating positions of weaker member states. Information will also be shared, so that most-favoured-nation conditions could be promoted. At the same time the Commission went further, receiving a mandate from the Council of Ministers to negotiate a legal framework for a Trans-Caspian pipeline – an essential for enhancing the reach of the Nabucco project. A legal framework does not guarantee commercial agreement on supplies by the importing (private-sector) and exporting (mainly private-sector) enterprises concerned.

Stability of policies

The interaction between the three climate-oriented targets ('20-20-20') creates a planning problem for policy: how simultaneously to hit the three different objectives without wasteful over-achievement in any one area. Investors face a similar problem. For both, there is the uncertainty about future changes in policy. Changes are inevitable. Reality will change as technical 'fixes' work, do not work, or turn out to carry unacceptable costs. Consumers' (and voters') preferences will change as perceptions of threats change.

167 ENTSOE, European Ten Year Network Development, 2010–2019, December 2009.

168 For this section, see David Buchan, 'Expanding the European Dimension in Energy Policy', OIES SP 23, October 2011.

The security objectives reflected in internal EU policies are in general straightforward, though the details matter – investment in interconnection, minimum back-up for most important sources, etc. The same cannot be said of the EU intervention in the constantly evolving competition between pipeline projects in which the Russian policy is clear and individual member states and their companies have different interests.

Implications for gas markets

The role of gas in the EU power market is more likely to grow than to recede. It is and will be substantial, and could contribute to the competitiveness of the EU, but timing and scale are uncertain. There will be a premium on options, and flexibility, and delays in major commitments to untried technology or services.

The 20-20-20 policies and their unknown successors will have the effect of crowding the gas market in the power sector between renewables obligations whose future is uncertain, and coal, which depends on success with carbon capture and storage (CCS).

There are also technical uncertainties (renewables, CCS, shale gas) and uncertainties about Russian, Turkmenistani and Kazakhstani marketing and pipeline strategies. Expectations about the rapid expansion of shale gas may turn out to be as exaggerated as those for the rapid deployment of CCS.

Asian gas markets

Asian markets for natural gas are expanding very rapidly in countries that lack the resources to expand production to match (with the possible exception of China if its shale resource is developed). The main sources of increased supply – as LNG – are Australia, Qatar and offshore East Africa. While Australian LNG is in private-sector, competitive hands, Qatar's production (though undertaken with foreign partners) is marketed under the control of the state gas company. Qatar has the financial and physical capacity to support the price of gas in Asian LNG markets (currently linked to the price of oil) in times of surplus by shifting marginal sales to the lower-priced Atlantic market where Qatar is not a significant supplier (at present, it is maximizing sales in Asia, where prices are not under threat). Importers such as China would have the opportunity to challenge this market structure through their access to Central Asian and Russian gas (not necessarily low-priced) and their domestic production. Chinese companies are also expected to bid aggressively for participation in the offshore East Africa private-sector projects.

The key question for Northeast Asia is how quickly, and at what price, new Russian gas can become available for Chinese, Korean and Japanese markets.

The pricing of gas in the Asian markets is difficult to foresee. Governments and the power industries will seek to reduce the high prices paid for gas imported into Japan and other Asian markets under oil-linked formulas. The producers will resist. However, some producers may scramble to secure volumes at lower prices if shale gas (in China) is seen to have the possibility of changing the overall Asian gas balance as US shale gas is changing Atlantic gas prospects.

The implication for the gas industries – production, importing and selling – is that the optimistic outlook for gas in Japan is tinged with the risk of over-investment against an electricity demand which will be stepped down by government policy, and the competition from businesses whose products and services reduce the use of electricity, and against possible pressures on Asian gas prices.

China

The prospects of the market for gas in China need to be reappraised continually in the light of a changing balance between:

- The rising demand for energy: small changes in high rates of growth have a big impact on target years for investment projects;
- China's ambitious commitments to increasing renewables and nuclear in the power sector: more gas would mean more flexibility in executing those policies;

- Perceptions of the security risks of dependence on imports via pipelines from Central Asia and Russia, and LNG imports from Australia and the Middle East;
- The speed with which China's shale gas resources are developed;
- The development of gas pricing in the Asian markets.

Under current policies, and with GDP growth rates slowing from 8% beyond 2020,¹⁶⁹ China will use nearly five times as much gas in 2030 as today, in an energy market increasing at only 1.5%. A 1% difference in the growth rate would change the projections for 2030 by about 20%.

However, in these projections, China would remain behind Europe, the US and Japan in its use of gas, both in the economy and in the power sector (see Table 15). Higher use may result from the development of shale gas in China, and/or international trade.

Table 15: Gas in China compared with other major economies

	Gas demand 2009 (BCM)	Gas demand 2030 (BCM)	Gas share of total energy 2030 (%)	Gas share of power sector 2030 (%)
China	87	405	12	5
India	54	131	9	10
Japan	90	114	21	25
EU	462	588	29	26
US	593	636	25	18

Source: International Energy Agency, WEO 2011.

The figure for 2030 in the WEO understates more recent Chinese plans, which point to a demand of 500 bcm (17,650 bcf) by 2030.¹⁷⁰

Climate change objectives

The 12th Five-Year Programme (2011–15) targets a reduction in carbon intensity of 17% from 2010, by 2015. Targets have now been set for regions. A carbon trading scheme will be launched in 2013, and goals for solar and wind power are being revised upwards. There will be feed-in tariffs for domestic solar. Under the 2006 renewable energy law, grid operators must buy all available renewable energy, with prices fixed at provincial level – usually through a bidding process, plus a nationwide subsidy for biomass.¹⁷¹ In the future, Chinese policy, as expressed the 12th Five-Year Programme, is to reduce the proportion of coal used the power sector, with renewables, nuclear and hydro as the replacements, as Table 16 shows.

Table 16: Share of primary fuels in power generation in China, 2009–30 (%)

	2009	2030	Change 2009–30
Coal	89	76	-13
Hydro/nuclear	8	14	+6
Renewables	0	5	+5
Gas	2	5	+3
Oil	2	0	-2

Source: International Energy Agency WEO 2011.

Rounded numbers.

¹⁶⁹ According to IEA, WEO 2011.

¹⁷⁰ Zhu Jiping, Vice President of CNPC, Doha, November 2010, <http://www.cnpc.com.cn/en/press/speeches/> China's Natural Gas Demand and CNPC's Natural Gas Business Strategy.

¹⁷¹ For a detailed review of Chinese renewable energy policy, see Andreas Dittrich, *Climate Policy in the People's Republic of China*, International Report 4, Konrad Adenauer Stiftung, Shanghai, 2011.

Imports

The net effect of the trends shown in Table 18 is that there should be no increase in the share of imported fuels – gas and oil – in Chinese power generation.¹⁷² There would be an absolute increase in imports to about 150 bcm (5,300 bcf). Economics and policy suggest a diversification. Agreement has been reached to increase the Turkmen pipeline capacity from 30 billion cubic metres per year (bcm/y) to 65 bcm/y,¹⁷³ which corresponds to 2,900 million cubic feet per day (mcf/d) and 6,300 mcf/d respectively. 120 bcm (4,200 bcf) of LNG import capacity will exist by 2015. There are seemingly endless negotiations with Gazprom, which seems to offer supplies through a 68 bcm (24,000 bcf) pipeline to be built from Siberia, but no commitments yet. (Alternative disposals for Siberian gas are shipping to Europe or building a pipeline for an LNG terminal on the Russian east coast.) There is therefore the prospect of a surplus of import capacity to support higher levels of imports. Uncertainty about import levels and infrastructure utilization therefore exists for investors in gas supplies dedicated to China.

The prospects for imported gas into China are positive, but uncertain as regards value and price as well as demand. Volumes and prices will be influenced by the strength of development of renewables and nuclear in the power sector. Chinese production of shale gas in the longer term could change the expected growth and dependence on imports. Meanwhile, a competitive situation is developing in which Chinese companies have choices between Russia, Turkmen, Qatari, East African and Australian incremental supplies (as well as continuing supply from Indonesia). Both buyers and sellers (and investors in infrastructure) will have to adapt to this more fluid market structure and pricing mechanisms.

Shale gas

The US Geological Survey estimates, with a wide range of uncertainty, that China's shale gas resources at 36 trillion cubic metres (tcm), or 1,270 trillion cubic feet (tcf), may exceed those of the US. The government has designated shale gas as a separate resource, open to bidding from Chinese companies and foreign partners who will be expected to bring technology. Developing such resources into proved reserves and actual supply is likely to be difficult and slow. China lacks the industry skills and capacity of the US; there will be problems about water supply in the areas concerned and there is no existing infrastructure to move the gas to the areas of demand. The Plan for Shale Gas published in March 2012 recognizes these difficulties, calling for more appraisal, development of technology in China, developing a contract system for 'investors of various backgrounds' to tender for shale gas (non-tradable) rights, concessions for importing equipment not available in China, and infrastructure to move the shale gas produced. The plan targets 6.5 bcm production by 2015. Longer-term targets will be set in the 13th Five-Year Programme.¹⁷⁴

Japan

Nuclear sunset?

The energy outlook for Japan, and Japanese energy policy, have been in suspense since the Fukushima nuclear disaster of March 2011. By November 2011 only 11 out of 54 nuclear plants were operating; the remainder were likely to be closed by summer 2012.¹⁷⁵ The closures are not necessarily permanent: they are to meet safety reviews and assessments. However, permission to restart plans depends on the relevant local authorities as well as the central government, and the overall prospect may not become clear until late 2012 or 2013. Meanwhile, electricity supplies will be short; the system will have to meet summer peak demand with less capacity than in 2011 and a deficit of 9% of demand is foreseen.

Energy-saving technologies will be developed and applied to mitigate the discomforts of the power losses experienced in 2011. METI has issued detailed guidelines for saving electricity in a variety of

172 See discussion in J.V. Mitchell, *More for Asia: Rebalancing World Oil and Gas*, Chatham House, December 2010.

173 The West–East gas pipeline provides a continuous route for pipeline gas from Turkmenistan to Shanghai. Turkmenistan gas resources would support higher levels of imports and diversify Turkmenistan's export markets from being dependent on Ukraine (accessed via Russia) and Russia itself.

174 Norton Rose: <http://www.nortonrose.com/knowledge/publications/64620/chinas-12th-five-year-plan-for-shale-gas>.

175 In June, it was announced that two plants would be reopened.

applications, reducing demand by 5% through a combination of tariff reforms and budget-supported energy conservation projects, and a 4% increase in supply (of which a third will be from non-traditional utilities).¹⁷⁶ These measures are likely to be permanent.

Policy is under review. A consultation document was published by the National Policy Unit in June 2012. It stressed the need to develop a nuclear policy which receives public support, as well as contributing to the principles of previous policy: the ‘3 Es’ of efficiency, environment and energy security. Previous policy had looked for 50% of electricity to be generated from nuclear by 2030. The nuclear share was expected to increase, while the contribution of biomass and renewables remained small relative to other leading economies with more land area. The consultation paper presents scenarios for zero, 15% and 25% nuclear. The consultation process is intended to lead to a new policy framework by December 2012.

In the previous policy the share of gas in Japan’s primary energy mix was expected to grow from 17% to almost 21% by 2030, with its share of the power market almost constant at 25%. The question is how far this will increase as a result of the inevitable cutback in nuclear and the difficulties of expanding renewables in Japan.

Before the flood

About 60% of gas supplied in 2030 would have been used in the power sector under pre-review policies. Table 17 shows the current policies projection on this basis.

Table 17: Supply of primary fuel to the power sector, 2009–30 (% share)

	2009	2030	Change 2009–30
Nuclear	34	37	+3
Coal	27	25	-2
Gas	24	25	+1
Oil	8	3	-5
Renewables/hydro	5	7	+2

Source WEO 2011.

Source: International Energy Agency, WEO 2011.

Rounded numbers.

Options: gas versus demand efficiency

The policy review will need to take account of changes affecting Japan from outside: the development and future shape of Asian gas markets, and possible supplies to Asia from high-cost Russian production. At the same time Japan will presumably remain committed to the decarbonization of its economy. The previous policies had relied on electrification, fuelled by nuclear, to reduce the use of fossil fuels and GHG emissions. Delays and possibly eventual reversal of nuclear construction would close down this strategy.

Japan has almost no fossil fuel resources and limited renewables opportunities. It is likely that policy will emerge with an even stronger emphasis of avoiding the use of energy, particularly electricity, by improving technologies of consumption. There is no other general option for Japan. To replace 20–25% of electricity demand (i.e. the whole nuclear contribution) by 2030 by demand technology alone would be a great challenge but one of a kind that industrial Japan and Japanese society have coped with in the past. It would be likely to precipitate Japanese companies into global leadership in electricity- and energy-avoiding technologies.

Meanwhile, it seems inevitable that more gas-fired generating plants will be built as a replacement for nuclear. The competition for these will not be coal, which is rendered unattractive by climate change commitments, (and CCS would be a longer-term and less certain solution than reducing electricity demand). The competition for new gas will therefore be from the demand side; from industries that divert

¹⁷⁶ IEEJ, *Japan Energy Brief 16*, November 2011.

consumers' expenditure and investment from buying gas-generated electricity to buying equipment and services that avoid its use.

Implications for the gas industry

Producers, pipeline companies, distributors of gas, and generators and grid owners, and distributors of electricity face different strategic challenges:

- For *gas producers*, the market uncertainties suggest the importance of cost;
- For *generators*, ensuring adequate supplies of gas in the event that environmental restrictions increase the cost and reduce the local availability of coal;
- For *system operators*, the increase in intermittent generation will present questions of system reliability which may require not only back-up capacity but back-up access to primary fuels on a flexible basis – i.e. storage.

Appendix 4: Who Are the Investors?

Beth Mitchell

Syndicated loan providers

This market collapsed in the wake of the financial crisis as banks had to address not only bad debts arising from the previous period but much more restrictive capital adequacy requirements. While the former will be worked through as the economic cycle progresses, the latter is a structural change and will persist. This affects both the quantum of financing available and the price at which it is offered. This has particularly affected NOCs for which syndicated loans are overwhelmingly the source of external financing. Many European banks have withdrawn from the MENA region entirely and local capital markets are nowhere near large or sophisticated enough yet to provide the necessary funding.

The NOCs will have to fund a higher proportion of projects via state budget allocations to add to their retained earnings. The debt to equity ratios in all sections of the value chain have already shifted to reflect the difficulty of raising debt: downstream from 30:70 to 35:65 in oil-based refining/petrochemicals and 40:70 in the gas-based downstream.¹⁷⁷ This has two effects: first, the weighted average cost of capital rises as the 'equity' component does; and, secondly, projects are competing more with other uses for the money, perhaps in wider development aims for the nation.

Bond investors

Bonds have been the major source of funding for the IOCs, at a project, joint venture or company level. With availability and pricing tied more to financial stability than short- to medium-term business development, the industry (with the exception of company-specific crises) has been more affected by the collapse of the overall lending than by investors' concerns about the industry specifically. After the long period of very loose monetary conditions, the severe deleveraging by banks and governments has reduced the quantity of funding available and increased its price. Notwithstanding the increased preference for bonds at the expense of equities, the pool is smaller and this seems unlikely to change in the short to medium term.

What is likely is a continued preference for quality, which the largest IOCs retain. Of the European large IOCs, the credit ratings range from AA (stable) for Royal Dutch Shell, AA- (stable) for Statoil and Total, A (stable) for BG & BP, A (negative) for ENI, and BBB- (negative) for Repsol.¹⁷⁸ The European companies have about \$100 billion to refinance between 2012 and 2014, though some have considerable free cashflow during the period (Statoil, ENI and Royal Dutch Shell) and all have the potential to dispose of assets.

Traditional equity investors

Traditionally equity investors have been savers in developed markets, largely through pensions or other pooled vehicles. The investment implications of ageing populations in the developed markets have been causing a move away from equities towards bonds. It has even been suggested that after fifty years of the cult of the equity we are now entering the cult of the bond (though presumably it would be hard for this to survive a resurgence of inflation). There is no clear evidence that the shift towards bonds which has been seen in final salary pension schemes to reduce company risk will continue; it might be argued that as people live longer and have longer in retirement their requirement for inflation protection (better

¹⁷⁷ Ali Aissaoui, 'MENA Energy Investment: Broken Momentum, Mixed Outlook', *MEES*, 3 October 2011.

¹⁷⁸ Source: Bloomberg as of 23 May 2012.

provided by dividend growth than bonds unless there is massive issuance of index-linked bonds) would be better met by equities than bonds. Since almost all schemes are now defined-contribution rather than defined-benefit, with the risk shifted from the funding company to the individual, the emphasis will be more on seeking growth. Thus once we emerge from this very volatile period, there may well be a revival in fund flows into equities. In an era of scarce growth, companies that can demonstrate growth are rewarded by very high ratings (as in the period of the 'nifty 50' in the US).

A number of the NOCs have listed at least some of their shares – from Statoil which is to all intents and purposes operationally independent, via Petrobras which has listed, then restructured its shareholdings and has an established international shareholder base, to the Chinese companies Sinopec and CNOOC which have used listing as much as a framework to bring the structure and operations up to international standards as to raise money.

Equity investors are often criticized for being 'short-term', but it is important to understand what equity fund managers are hired to do, and on what terms they are judged. Fund mandates are almost always structured on the basis of twelve-month performance (relative to an index or benchmark) so investors have a 12–24-month time horizon, and are extremely concerned to avoid a period of severe underperformance by a share, even if the longer-term prospects look attractive. However, there are almost always turnover restrictions (limits to the proportion of the fund that can be bought/sold in a given year) and of course it is difficult to generate good investment ideas, so investors hope that a company's prospects and progress can continue to be relatively attractive for a multi-year period (and that management can keep expectations at a level which can be exceeded). This can go on for as long as ten years, and can be ended by management overreaching itself, industry structure changing, market share limits being reached or just the law of large numbers limiting the potential for further growth. There are many examples of this across the market: Apple (after a troubled period), Tesco (until market saturation and US expansion), Logica (technological change), Inditex (still going but watch out for space growth slowing), Burberry (same), Novo Nordisk (watch out for a real alternative to insulin). In the oil and gas sector BG and Tullow are recent examples.

All equity fund investors care about corporate social responsibility (CSR) to some extent, whether explicitly in its being required in the fund mandate or implicitly in wanting to avoid the share price damage caused by a disaster or scandal. While the oil and gas sector does not tend to feature in tightly defined SRI or green funds, the avoidance of environmental damage and robustness against climate change regulations/laws/requirements is important to share prices. Access to licences/projects is also dependent on regulatory authorities in non-NOC countries and requires some degree of population acceptance, so the good of the business is increasingly tied to demonstrated practice. All of the companies have a commitment to CSR and environmentally responsible operating practices, though concerns remain.

Developing markets: savers but not yet equity investors

Investors in developed markets currently hold nearly 80% of the world's financial assets (\$157 trillion)¹⁷⁹ but these assets are growing far more slowly than those held in emerging markets. In general, the latter are held in bank deposits and it may take many years for investors to demand and markets to supply viable equity markets. Some emerging-market companies access developed-country stock markets, through ADRs in the US or London listings. Many mining companies have done so, though this is not without problems: as the evidence of many Hong Kong-listed Chinese companies demonstrates, corporate governance and the reliability of accounts are very variable.

While in the very long term, clearly, emerging-market savers will be large-scale investors, that long term is probably more than a decade away. The mechanism for the harnessing of such savings into more complex investments depends on systems put in place by the relevant governments (models might be something akin to the Japan Post Office Savings structure or the compulsory savings schemes of Singapore which are invested centrally). Trust in the governments and in the schemes will be crucial.

¹⁷⁹ McKinsey Global Institute, 'The Emerging Equity Gap: Growth and Stability in the New Investor Landscape', December 2011.

It is estimated¹⁸⁰ that the share of global financial assets in publicly traded equities could fall from 28% in 2011 to 22% by 2020, leaving a gap of around \$12.3 billion (between estimates of companies' needs to fund growth and investors' desired supply of equities),¹⁸¹ largely in emerging countries where only a tripling of equity allocations could alleviate it, though a gap also seems likely in Europe. This could lead to the cost of equity to companies rising sharply and push the shift to bond financing further. Conversely, US companies in aggregate had \$1.4 trillion on their balance sheets at the end of 2010 (though this skewed by some very large balances at ExxonMobil, Apple etc.).

Sovereign wealth funds: an emerging force, but in most cases diversifying away from oil and gas exposure

Sovereign wealth funds (SWFs) are largely concentrated in the Middle East and Asia and are generally quite opaque (with Norway an important exception) in their scale, investments and returns. They are, however, an increasingly important force in investment and will continue to be so. SWFs are estimated to manage about \$5 trillion of assets, roughly twice as much as the hedge fund industry. They are increasing their assets, to an estimated \$10 trillion by 2020,¹⁸² whereas the hedge funds have seen several years of outflows and are managing about half as much as at the peak of the market.

Although SWFs are perceived as having far more freedom from short-term restrictions than other institutional investors, in fact each has its own aims and restrictions. Work done by the EDHEC-Risk Institute¹⁸³ divides them into three categories:

- *Natural resources funds*, comprising about 70% of total SWF assets, and with the investment aim of being a stabilizer against fluctuating commodity prices and phasing national wealth between generations (e.g. Norway, UAE).
- Foreign reserve funds, designed to hedge out the impact of commercial surpluses while generating high enough returns to exceed the cost of sterilizing the impact on the local monetary base of capital inflows (e.g. China, Korea, Singapore).
- *Pension reserve funds* (the smallest category), where retirement pensions are funded rather than paid out of future tax revenues (e.g. France, New Zealand, Ireland).

Their detailed dynamic asset allocation modeling suggests that these funds must consider:

- Where the money is coming from and the risks to those inflows;
- What the money is to be used for and what would be a relevant benchmark e.g. inflation-linked;

From this they suggest a tripartite optimal asset allocation strategy:

- A performance-seeking portfolio, typically heavily invested in equities;
- An endowment hedging portfolio, customized to meet the risk exposure in the inflows;
- An inflation hedging portfolio, heavily invested in assets chosen to hedge the liability inflation expected for the specific fund;

and separate hedging for interest rate and equity (Sharpe ratio) risk.

Some SWFs, Norway for example, are trying to hedge away from their endowment of natural resources, but it might well be argued that for the SWFs of the Asian nations, which are very large importers of oil

180 Ibid.

181 Ibid.

182 Deutsche Bank, 'Sovereign Funds, State Investment on the Rise', September 2007.

183 Lionel Martellini and Vincent Milhau, 'Asset-Liability Management Decisions for Sovereign Wealth Funds', October 2010.

and gas, it would make sense to invest in the upstream portion of the industry. With sensitivity in many countries to sales of 'strategic assets' to other sovereign states, NOCs do use their investment arms to enact their M&A activities. Exactly how this is structured depends on specific portfolio allocation rules. The Kuwait Investment Authority (KIA) invests via the private equity and property divisions of its Kuwait Investment Office, while Abu Dhabi Investment Authority (ADIA) and Qatar Investment Authority (QIA) invest via IPIC, Mubadala and TAQA (ADIA) and Qatar Holding (QIA).

The restrictions on foreign ownership of energy assets may limit SWFs' ability to make the most of the opportunities arising from the credit crisis, at least in the energy sector. Qatar Holdings has bought a minority stake in Iberdrola and IPIC has taken over CEPSA; subject to permission, further significant investments are likely. It may be that, just as supermarkets in the UK turned out to be the logical owners of petrol retailing, the NOCs will become the logical owners of refining capacity (even in Europe) to secure the refining of their crudes, especially those with unusual specifications.

Infrastructure investment can also have a part to play in the inflation-hedging portion of a sovereign wealth fund,¹⁸⁴ given that the revenue streams of many infrastructure assets are contractually linked to inflation e.g. toll roads, ports and pipelines. Asset-heavy, long-life businesses can also be somewhat defensive against inflation in the medium term, though there can be short-term dislocation (long-term contracts, excess capacity) and the quality of the embedded inflation assumptions for each project is crucial. Within the oil and gas industry assets such as pipelines would fall into this category.

Pension schemes: investing more directly into infrastructure

There are some efforts to promote more investment by pension schemes in infrastructure, but the extent of take-up is not yet clear. The European Commission and European Investment Bank have designed the Europe 2020 Project Bond Initiative in an attempt to raise a substantial contribution towards the €1.5–2 trillion that they hope to spend on EU infrastructure by 2020. The UK government also hopes to involve pension funds more directly in infrastructure investment. Mandatewire¹⁸⁵ has identified £1.5 billion of quantifiable future cashflows into this asset class based on commitments made in the first quarter of 2012, which is greater than inflows into property, equities or other alternative investments. Consultants suggest that pension funds, which can tie up funds for ten years or more, can benefit from the 'illiquidity premium' associated with infrastructure and that the characteristics of infrastructure are well matched with pension funds' requirements: 'Infrastructure is stable, it's essential, it's inflation linked or has inflation protection.'¹⁸⁶

Again, from the oil and gas industry, pipelines stand out. It has also been historically the case that commodity prices have tended to rise coincidentally with inflation (and in some cases to contribute to it), so if this relationship holds in the next period, which it may not, given the concerns expressed elsewhere in this study, upstream investments may provide some inflation protection for both SWFs and pension funds. It is possible that some of the larger funds could be interested, in their performance-related rather than their inflation-hedging capacity, in investing in upstream projects, perhaps via a product that packaged participation in a number of projects in their harvest phase.

Private equity: evolving in the new circumstances

During the boom period the combination of available cheap debt and rising equity markets led to the growth of a private equity model which consisted of buying a business, loading it with debt and selling it back to the market in a short time, at a very much higher price: rather more financial restructuring than business restructuring (Debenhams being one of the most egregious cases at 29 months). But with neither of these conditions pertaining any more, private equity is returning to a more fundamental approach

184 Partners Group, 'Building an Infrastructure Portfolio', March 2012.

185 *Financial Times* service.

186 Brandon Prater, co-head of private infrastructure at Partners Group.

where it can be very productive, with a longer time horizon and more active participation than equity investment. In terms of the oil and gas industry, stable projects with reasonably predictable cashflows would be the most relevant (pipelines again), but there could be an opportunity in companies or packages of assets that could be characterized as 'gleaners after the main harvest', buying into very mature fields and using new technology, and extracting the last available oil. There are successful examples of this approach in the North Sea and such a model might very well be attractive to private equity. Private equity can also provide great value to the oil and gas industry by funding, restructuring and expanding companies which develop technology for all stages of exploration and production.

In the aftermath of the banking crisis, with capital being withdrawn and balance-sheet gearing being significantly reduced by the banks, private equity is emerging as an alternative source of capital for business. GSO, the credit arm of Blackstone, has been very active. With \$47 billion of assets under management, GSO has the capability to provide large-scale funding for deals and projects – whether directly to business or to recapitalize existing private equity investments structured in very different circumstances. In the oil and gas industry, GSO is involved in financing the Sabine Pass LNG plant in Louisiana (initially intended to accept imports but redesigned for exports, given the transformation of the US gas market). Of the \$10 billion required by Chenière to fund the building of the liquefaction plant, GSO has pledged \$2 billion with \$4 billion committed by eight banks and an equity issue making up the balance.

Hedge funds: still in the market but less of a force

The hedge fund model, based on high levels of gearing and rising asset markets, is far more challenged by tight credit conditions and volatile markets. In general hedge funds have short investment horizons (partly because of the cost of gearing and stock borrowing), so tend to focus on point events (earnings announcements, deals, etc.); and since they need constant valuation data they tend to stick to quoted vehicles or commodities with a market clearing price. Clearly they can get involved in complex instruments to proxy exposure and could use such instruments to manage a longer-term commitment, but they do not seem likely to be large-scale providers of funding to industry

Commodity traders

There have apparently been indications from Glencore that it might be interested in owning oil and gas production assets as part of its overall commodity exposure strategy. Not many details have become public, and Xtrata is presumably time-consuming, but Glencore is founded on mine ownership and would not find it a completely new challenge. Whether it would want to go into partnerships or own whole projects and to what extent it would wish to be involved at an operational level is not clear.



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