

CURRENT TRENDS IN OIL AND GAS INVESTMENT

HIGHLIGHTS

- Oil and gas industry investment has surged in recent years. In 2005, investment by the industry reached \$340 billion dollars, 70% more than in the year 2000 in nominal terms. However, most of the increase was due to rising materials, equipment and labour costs, especially since 2004. Expressed in cost inflation-adjusted terms, investment in 2005 was only 5% above that in 2000.
- Major oil and gas company plans point to an investment increase of over 57% in 2006-2010 compared to 2001-2005. If those plans are fully implemented and their spending forecasts prove accurate, oil and gas investment would rise from \$340 billion in 2005 to \$470 billion in 2010. In real terms, however, investment is 40% higher in the second half of the decade than in the first. The upstream sector will absorb almost two-thirds of total capital spending of which two-thirds will go to maintaining or enhancing production from existing fields.
- Upstream investment is planned to add close to 21 mb/d of new crude oil production capacity during 2006-2010. However, project slippage and a decline in the production capacity of existing wells mean that the net increase in capacity could be only about 9 mb/d. This is about 1.3 mb/d more than the projected growth in world oil demand to 2010 in the Reference Scenario and 3.3 mb/d more than in the Alternative Policy Scenario. However, capacity additions could be smaller on account of shortages of skilled personnel and equipment, regulatory delays, cost inflation and geopolitics.
- Refinery investment has also risen, from \$34 billion in 2000 to an estimated \$51 billion in 2005. Industry spending plans point to more modest increases in the next five years, with investment reaching \$62 billion in 2010. As in the upstream, much of this increase is explained by higher unit costs. Around 7.8 mb/d of throughput capacity will be added by 2010.

- The five years to 2010 will see an unprecedented increase in capital spending on new LNG projects. A massive 167 million tonnes (226 bcm) per year of new liquefaction capacity is under construction or planned to come on stream by 2010 at a cost of about \$73 billion. World LNG capacity will almost double to 345 Mt/year if these projects are all completed on time.
- Beyond the current decade, higher investment in real terms will be needed to maintain growth in production capacity. Future projects are likely to be smaller, more complex and remote, involving higher unit costs. Slowing production declines at mature giant fields will require increased investment in enhanced recovery.

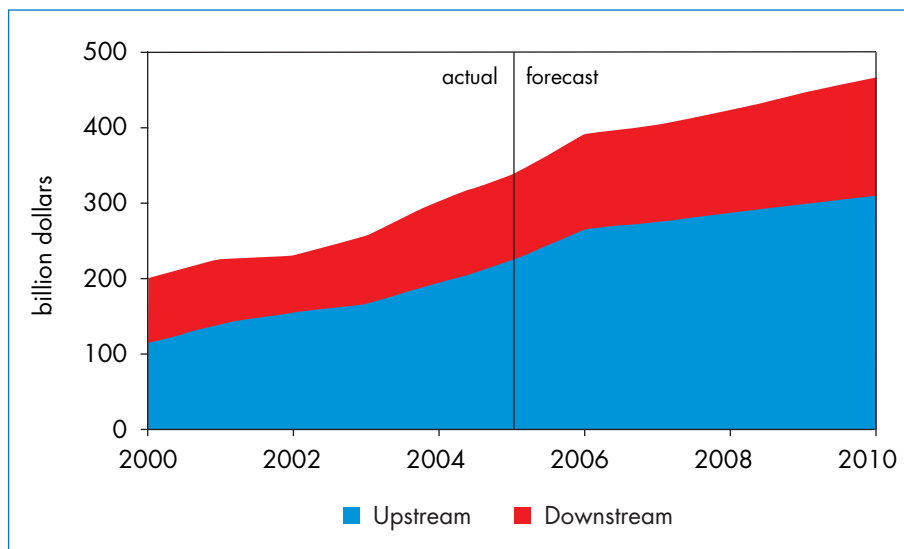
Overview

Capital spending by the world's leading oil and gas companies increased sharply in nominal terms over the course of the first half of the current decade and is planned to rise further to 2010 – the end of the period analysed in this chapter.¹ Between 2000 and 2005, capital spending grew at an average rate of 11% per year. In 2005, total investment by the industry reached \$340 billion, up from \$200 billion in the year 2000 – an increase of 70%.² The increase was particularly strong in 2004 and 2005, with most of the increase going to the upstream sector (Figure 12.1). The increase in spending was due to sharp increases in costs, caused largely by higher international prices for cement, steel and other materials used in building production, processing and transportation facilities, as well as increased charges for oilfield equipment and services, plus increased energy-input costs. In cost inflation-adjusted terms, the capital investment in 2005 was only 5% higher than that of 2000. In 2001-2004, real spending was, on average, 10% higher than in 2000. Box 12.1 provides a description of the methodology used to analyse near-term investment trends.

1. Because of data deficiencies, downstream oil and gas investment in this chapter primarily covers oil refining, oil pipelines, oil tankers, LNG chains and gas-to-liquids (GTL) plants. The long-term projections in Chapters 3 (oil) and 4 (gas) also include bulk gas-storage facilities, gas-transmission pipelines (cross-border and national systems) and gas-distribution networks.

2. All the investment figures in this chapter are expressed in nominal terms, unless otherwise specified. Where the figures have been adjusted for changes in cost inflation in the oil and gas industry, the qualifying terms “cost inflation-adjusted” or “real” are used.

Figure 12.1: Total Oil and Gas Industry Investment, 2000-2010



Source: IEA databases and analysis; part of the historical company data collated using Evaluate Energy *Petrocompanies* online database (www.evaluateenergy.com).

Box 12.1: Analysis of Current Oil and Gas Investment Plans

In addition to the long-term analysis of energy investment in the Reference and Alternative Policy Scenarios (described in Parts A and B of this *Outlook*), a detailed analysis has been made of oil and gas industry investment over the period 2000 to 2010. The objective was first, to assess whether the industry is planning to invest more in response to higher prices and the need for more capacity in the upstream and downstream, and second, to quantify the resulting additions to oil production and refining capacity. This involved four main tasks:

- A survey of the capital spending programmes of 40 major oil and gas companies, covering actual capital spending from 2000 to 2005 and their own forecasts of spending through to 2010. These companies included the major international oil and gas companies, independent producers and national oil companies (Table 12.1). The selection of the companies was based on their size as measured by their production and reserves, though geographical spread and data availability also played a role. The surveyed companies account for about three-quarters of world oil production and reserves, 65% of gas production and 55% of gas reserves. Total industry investment was calculated by adjusting upwards the

spending of the 40 companies, according to their share of world oil and gas production for each year.³ Downstream investment was also adjusted using project databases.

- A review of all major upstream projects worldwide that are due to be on stream by 2010. The sanctioned (approved by the company board) and planned projects covered total over 120. They include conventional oil and gas production and non-conventional oil sands. For each project, data were compiled on the amount and timing of capital spending and the amount of capacity to be added per year from 2006 to 2010.
- A survey of 500 oil-refinery projects, including greenfield refineries, refinery expansions and additions to upgrading capacity.
- A survey of 45 sanctioned and planned LNG liquefaction and gas-to-liquids projects as well as LNG shipping and regasification-terminal investments worldwide.

For each task, data were obtained from the companies' annual and financial reports, corporate presentations, press reports, trade publications and direct contacts in the industry. The year 2010 was chosen as the end-date for this analysis, because almost all the capacity that will be brought on stream by then is already under construction or at an advanced stage of planning due to the long lead times for large-scale projects. As with all studies of this kind, our analysis may not be accurate enough to estimate total industry investment authoritatively. Underestimation can occur due to the difficulties in capturing every project and every dollar of planned spending. Overestimation can be due to unforeseen changes in company plans.

On the basis of trends in investment planned or forecast by the companies surveyed, total industry investment for 2006-2010 is expected to be 57% higher than in the first half of the current decade. If their plans are fully implemented and their spending forecast proves accurate, total oil and gas investment will rise from \$340 billion in 2005 to \$470 billion in 2010. On average, about 67% of total spending in 2006-2010 would go to the upstream sector, 14% to oil refining, 7% to LNG and 12% to other

3. For 2006-2010, the shares were held constant at 2005 levels.

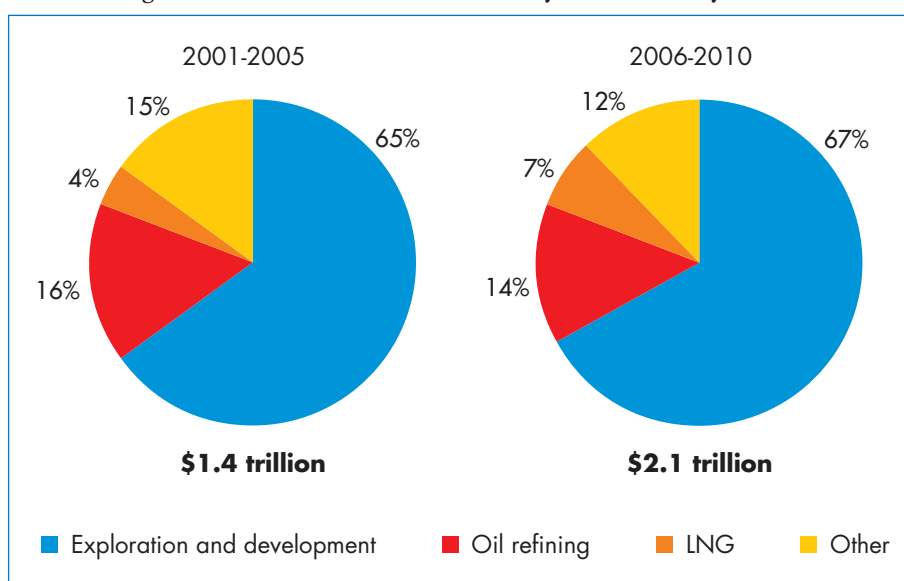
Table 12.1: Oil and Gas Production of Surveyed Companies by Type, 2005

	Oil (mb/d)	Gas (bcm/year)	Oil (mb/d)	Gas (bcm/year)
Independents				
Apache	0.2	13.1	2.8	46.7
BG Group	0.1	21.5	0.4	4.4
CNRL	0.3	14.9	0.3	545.9
Encana	0.2	33.2	1.5	88.9
Marathon	0.2	9.5	2.6	10.6
Hydro	0.4	9.5	1.6	12.3
Occidental	0.5	6.9	4.1	89.8
PetroCanada	0.2	8.3	2.4	20.8
Repsol	0.5	35.3	0.5	2.0
TNK-BP	1.6	11.0	2.4	30.5
Major international oil and gas companies				
BP	2.6	87.8	3.5	50.0
Chevron	1.7	43.7	2.3	31.7
ConocoPhillips	1.5	34.5	0.8	34.3
ENI	1.1	38.8	1.4	13.1
ExxonMobil	2.5	95.6	11.0	65.9
Shell	2.0	85.4	0.8	6.3
Total	1.7	54.2	1.2	–
			0.5	56.2
National oil and gas companies				
ADNOC				
CNOOC				
Gazprom				
Iraq National Oil Company				
Kuwait Petroleum Company				
Libya National Oil Company				
National Iranian Oil Company				
NNPC				
ONGC				
PDVSA				
Pemex				
PetroChina				
Qatar Petroleum				
Rosneft				
Saudi Aramco				
Sinopec				
Sonangol				
Sonatrach				
Previously state-owned companies				
Lukoil	1.8	5.8	1.9	22.9
Petronas	0.7	47.9	0.7	27.0
Total			62.5	1 816

Note: Data obtained from company reports and press statements.

downstream activities, including GTL, pipelines, oil tankers, distribution and retailing (Figure 12.2). The shares of exploration and development and LNG projects are set to be higher in 2006-2010 than in the first half of the decade. Upstream spending would grow at an average annual rate of 6.7% between 2005 and 2010. In cost inflation-adjusted terms, spending is projected to grow by about 40% between 2005 and 2010 – on the assumption that unit costs level off in 2007 and begin to decline gradually towards the end of the decade. By 2010, cost inflation-adjusted spending is expected to be 46% higher than in 2000.

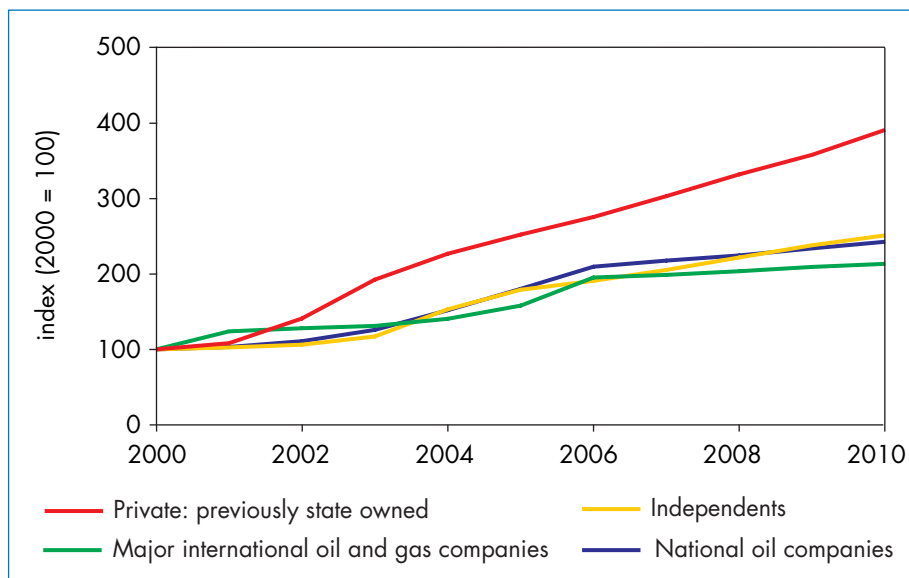
Figure 12.2: Total Oil and Gas Industry Investment by Sector



Source: IEA databases and analysis.

National oil and gas companies account for 35% of the total investment of all the companies surveyed from 2000 to 2010. Independents account for 15%, previously state-owned companies 11% and major internationals 38%. The share of the international oil companies falls between the first and second halves of the decade, while all others increase. The national oil companies' share of investment increases the most. While national, international and independent oil companies all more than double their investment between 2001 and 2010, the previously state-owned private companies quadruple theirs (Figure 12.3).

Figure 12.3: Oil and Gas Industry Investment by Type of Company



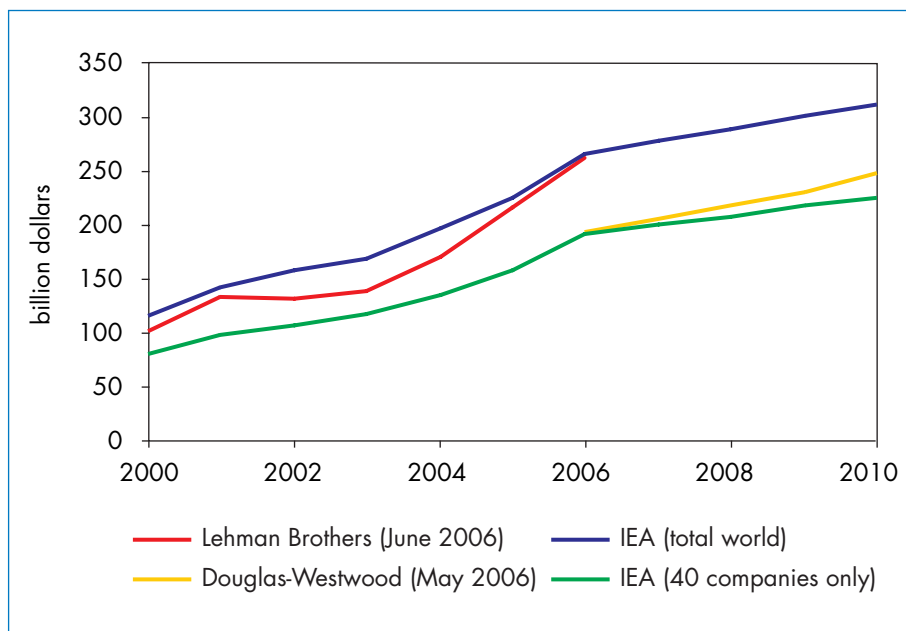
Note: See Table 12.1 for details of the breakdown by type of company.
Source: IEA databases and analysis.

Exploration and Development

Investment Trends

Capital spending on oil and gas exploration and development has risen sharply since the beginning of the current decade and, according to industry plans, will continue to rise through to 2010. Spending is estimated to have reached \$225 billion in nominal terms in 2005, twice the level of 2000. Much of this increase was due to cost inflation, an increase in the total number and size of projects under development, and a shift to more complex and costly projects in locations where no infrastructure exists. In real terms, spending rose steadily through to 2003, but levelled off in 2004 and in 2005 (see below). On current plans, spending is expected to increase by another 20% to \$265 billion in 2006 and then to rise further to about \$310 billion in 2010 (Figure 12.4). Cost inflation is expected to slow markedly by the end of the decade, partially driven by falling commodity prices and availability of new equipment to meet current sustained growth in activity. Total planned upstream spending in 2006-2010 amounts to \$1.4 trillion in nominal terms, compared with \$890 billion in the previous five years. These trends are broadly in line with those reported by other organisations, including Lehman Brothers and Douglas-Westwood, though the coverage of their surveys differed.

Figure 12.4: Investment in Oil and Gas Exploration and Development

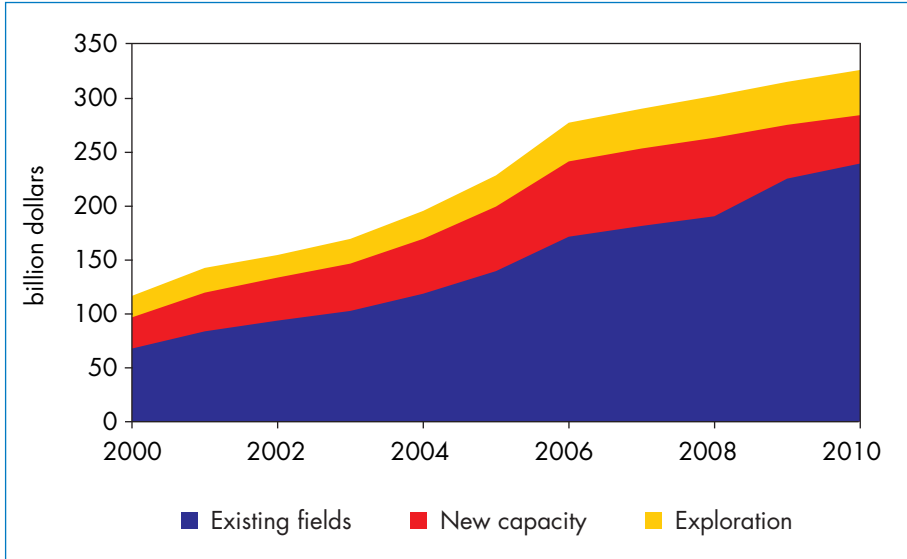


Source: IEA database and analysis; Lehman Brothers (2005); Douglas-Westwood (2006).

Over the period 2006-2010, spending on exploration is expected to amount to about \$194 billion, or 14% of total upstream oil and gas spending. The balance of almost \$1.2 trillion, or 86% of upstream spending, will go to development and production. We estimate that projects to develop new fields will absorb \$306 billion, of which the twenty largest will absorb over 50% (Table 12.2). Therefore, the remaining \$900 billion, or almost two-thirds of total upstream spending, is destined to enhance or maintain output at existing fields (Figure 12.5).

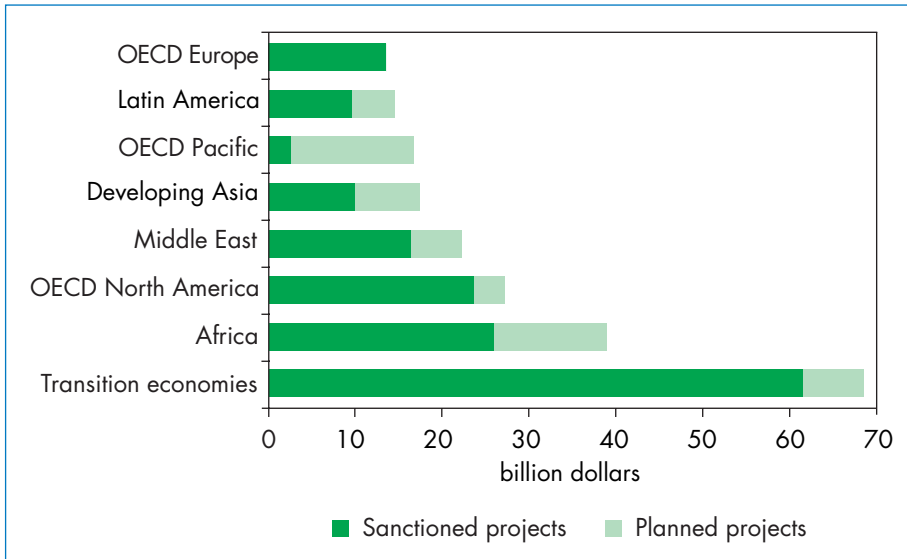
Almost all spending on new projects due to be on stream by 2010 has already been sanctioned, with many such projects already under development (Figure 12.6). More than half of the spending on new projects is going to Africa and the transition economies. Many of these projects are very large, involving fields in Nigeria, Angola, the Caspian Sea and Sakhalin that were discovered in the last decade. Many were sanctioned several years ago. Developers are now struggling to complete these projects on time and within budget in the face of huge increases in costs and limited availability of equipment and manpower (see below).

Figure 12.5: Upstream Investment by Activity, 2000-2010



Source: IEA database and analysis.

Figure 12.6: Sanctioned and Planned Project Investment on New Oil and Gas Fields by Region, 2006-2010



Note: Covers spending on the development of new fields only. Planned spending covers only those projects that have reached the front-end engineering design stage of the project.

Table 12.2: Sanctioned and Planned Upstream Oil and Gas Developments for Completion in 2006-2010

Project	Location	Operator	Completion date	Capacity addition		Total estimated capital cost (\$ million)
				Oil (kb/d)	Gas (bcm/year)	
Sakhalin 2	Sakhalin	Shell	2009	120	10	20 000
Sakhalin 1 (Chayvo)	Sakhalin	ExxonMobil	2006	250	10	17 000
Qatar GTL Pearl 1	GTL Qatar	Shell	2009	70	8.3	12 000
Kashagan Phase 1	Kazakhstan	ENI	2009	75	16	10 000
Athabasca Muskeg	Canada	Shell	2007	90	—	10 000
Ormen Lange	Norway	Shell	2008	—	25	8 850
Syncrude Phase 3	Canada	Canadian Oil Sands	2006	350	—	8 400
Qatar GTL	GTL Qatar	ExxonMobil	2009	80	—	7 000
Karachaganak 3 & 4	Kazakhstan	ENI, BG	2009	200	—	7 000
ACG 1 (West Azeri)	Azerbaijan	BP	2006	300	—	6 000
ACG 2 (East Azeri)	Azerbaijan	BP	2007	450	—	6 000
ACG 3 (Gunesli)	Azerbaijan	BP	2008	320	—	6 000
Snohvit	Norway	Statoil	2007	—	5.5	5 300
Khurais	Saudi Arabia	Saudi Aramco	2009	1 200	—	5 000
Prirazlomnoye	Arctic	Gazprom, Statoil	2010	155	—	5 000
Puqiang	China	Sinopec	2008	—	4.0	4 500
Vankorskoye 2	Siberia	Rosneft	2008	328	—	4 500
Aghami	Nigeria	Chevron	2008	230	—	4 000
Thunder Horse	GOM	BP	2008	250	2.1	4 000
Akpo	Nigeria	Total	2008	175	—	3 560
Tahiti	GOM	Chevron	2008	125	0.7	3 500
Dalia	Angola	Total	2006	240	—	3 400
Long Lake	Canada	Nexen	2008	60	—	3 120

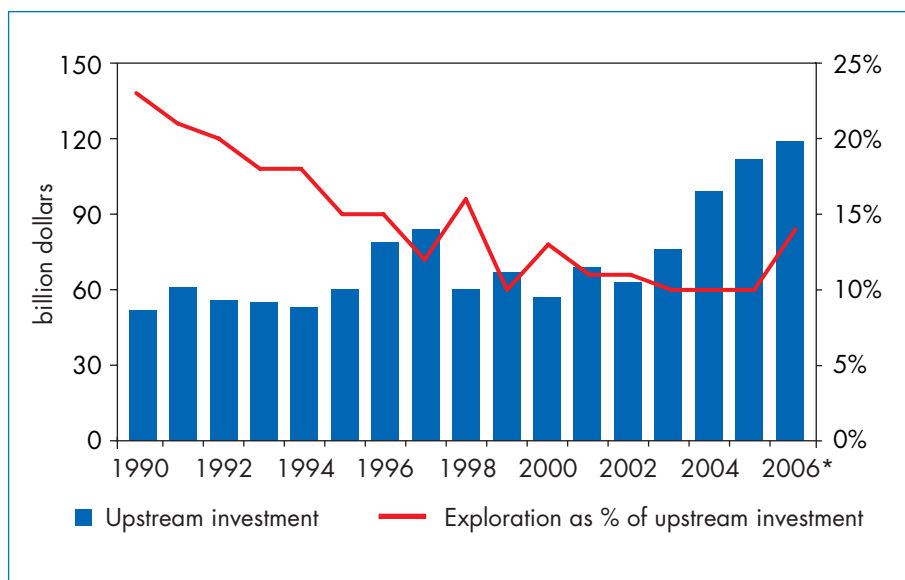
Table 12.2: Sanctioned and Planned Upstream Oil and Gas Developments for Completion in 2006-2010 (Continued)

Project	Location	Operator	Completion date	Capacity addition		Total estimated capital cost (\$ million)
				Oil (kb/d)	Gas (bcm/year)	
Atlantis	GOM	BP	2006	120	1.5	3 250
Shah Deniz	Azerbaijan	BP	2006	–	9.3	3 000
Tengiz expansion	Kazakhstan	Chevron	2006	250	1.0	3 000
Bonga South	Nigeria	Shell, Chevron	2007	150	–	3 000
Greater Plutonio	Angola	BP	2007	240	–	3 000
Escravos EGTL	GTL Nigeria	Chevron, Sasol	2008	95	–	3 000
Bayu Undan	Australia	Santos	2006	69	2.2	2 700
Kristin	Norway	Statoil	2006	126	5.5	2 600
Banyu Urip (Cepu)	Indonesia	ExxonMobil	2008	170	0.2	2 600
Shaybah & Central	Saudi Arabia	Saudi Aramco	2008	380	–	2 500
Kizomba C	Angola	ExxonMobil	2008	80	–	2 500
Tombua Landana	Angola	Chevron	2009	100	1.8	2 300
Shenzi	GOM	BHP Billiton	2008	80	–	2 200
Tyrithans	Norway	Statoil, Total	2009	70	–	2 200
White Rose	Canada	Husky	2006	100	1.5	2 000
Buzzard	UK	Nexen	2007	200	–	2 000
Demianskiy	Siberia	TNK-BP	2008	220	–	1 800
Moho-Bidondo	Congo	Total	2008	75	0.5	1 800
Others				5 073	30	40 920
Sanctioned			By 2010	12 666	135	250 500
Planned			By 2010	2 748	53	55 500
Total sanctioned and planned			By 2010	15 414	188	306 000

Note: Covers spending on the development of new fields only. Planned spending covers projects that have reached the front-end engineering design stage of the project-development process. GOM is Gulf of Mexico. Source: IEA database of 120 projects and analysis.

While most upstream investment continues to go to development of fields already in production, the *increase* in spending since the start of the current decade has been focused on development of new fields that were already discovered by 2000. Spending on exploration has risen in absolute terms since the beginning of the current decade, but has continued to decline as a share of total upstream investment (Figure 12.7). Although oil company exploration budget forecasts for 2006 indicate a reversal of this trend, putting exploration plans into effect will be hampered by the shortages of rigs and manpower over the next one to two years. If this is the case, there may be a shortage of new projects awaiting development when the current wave of upstream developments is completed early in the next decade.

Figure 12.7: Oil and Gas Exploration Investment



* Planned.

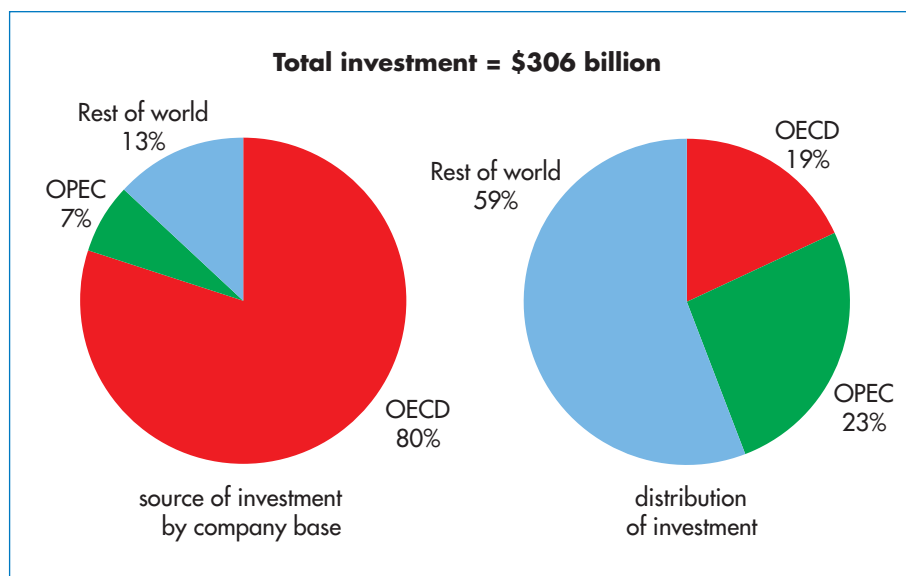
Note: Includes Apache Corporation, BG Group, BP, Chevron, CNOOC, ConocoPhillips, ExxonMobil, Lukoil, Occidental, ONGC, PDVSA, Petrobras, Petro-Canada, PetroChina, Repsol-YPF, Sinopec, Statoil and Total.

Source: IEA databases and analysis.

Oil and gas companies based in OECD countries continue to dominate global upstream investment. We estimate that they are responsible for about 60% of total investment over 2000-2010 and 80% of new project investment over 2006-2010. Although the share of total investment made by national oil companies in the Middle East is projected to be higher in the second half of the

decade than in the first, it is still remarkably small, at less than 10% of both types of investment. Development costs per barrel are significantly lower there than in other regions. Nonetheless, most of the new investment made over the five years to 2010 will go to projects in non-OECD countries: only 19% of the capital that will be spent will be on projects in OECD countries, while under a quarter will go to projects in OPEC countries and nearly 60% to projects in other non-OECD countries (Figure 12.8).

Figure 12.8: New Oil and Gas Project Investment by Source and Destination, 2006-2010



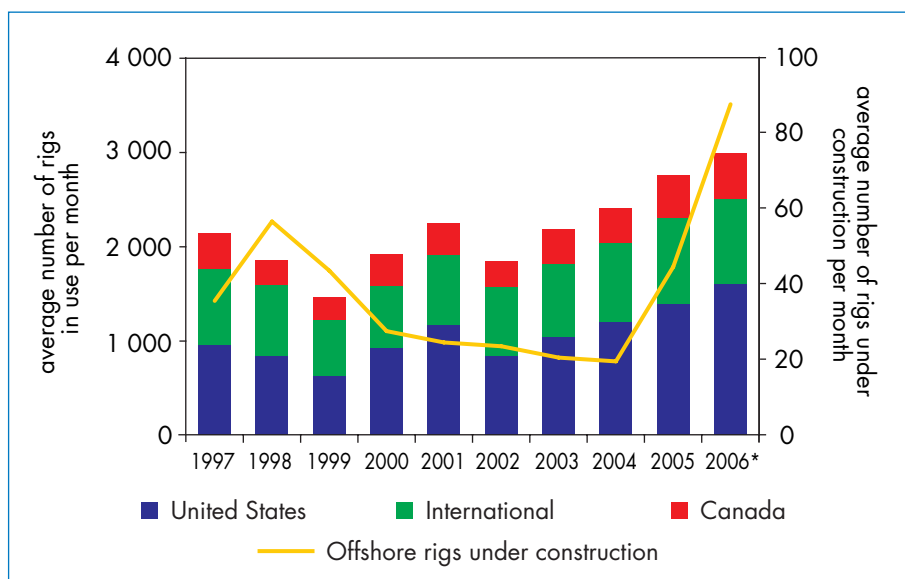
Note: Based on upstream projects surveyed. Includes GTL and LNG.
Source: IEA databases and analysis.

Impact of Cost Inflation on Upstream Investment

Exploration and development costs have increased sharply in recent years. In part, rising upstream costs have resulted from higher basic material costs, such as steel and cement. They have also been driven up by a sharp increase in demand for equipment and manpower as companies have sought to boost output in response to higher oil prices. An increase in the number of large-scale projects being developed at the same time, their remoteness and greater complexity and the increasing need for costly production enhancement at large mature fields have added to the upward pressure on cost. Drilling remains the single most expensive component of upstream activity. Since 2002, drilling-rig rates have risen more than any other cost component, with daily rates

increasing by as much as 100% for a North Sea jack-up rig to over 400% for a rig in the Gulf of Mexico. The main reason is a surge in demand for rigs which has driven effective utilisation rates up to 100% in most regions (Figure 12.9).⁴ Increases in equipment prices range from 20% for mechanical pumps to up to 50% for special fabrications of oil and gas production equipment. Construction labour now costs 25% more than in 2002, while at the top end of the labour market, rates for specialised expertise such as project management consultancy have increased by up to 80%.⁵ Rising oil prices have encouraged the oil and gas service industry to invest in new equipment and technology at a rate not seen since the late 1970s. In particular, the number of offshore rigs under construction has increased dramatically, holding out the prospect of lower rates in the future. Although nominal upstream investment has doubled between 2000 and 2005, we estimate that much of this increase has been absorbed by cost inflation (Figure 12.10). In 2005, upstream spending in cost inflation-adjusted terms was only about a fifth higher than in 2000. On the assumption that costs level off in 2006-2007, real spending is expected to rise by around a quarter between 2005 and 2010.

Figure 12.9: Active Drilling Rigs and Offshore Drilling Rigs under Construction, 1997-2006



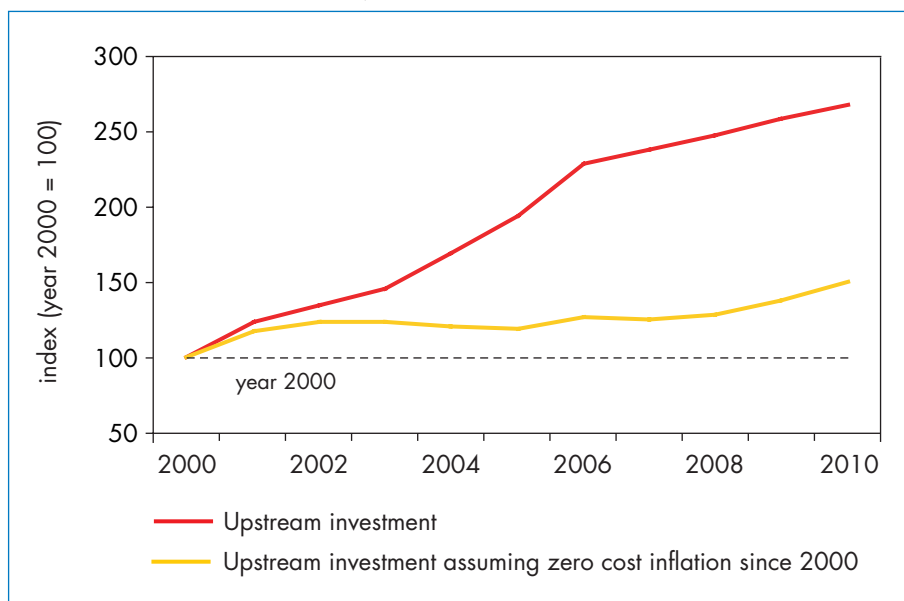
* To July.

Sources: Baker Hughes rig count (available at www.bakerhughes.com); ODS Petrodata.

4. See ODS Petrodata website (www.ods-petrodata.com).

5. Information obtained in communications with oil and gas industry.

Figure 12.10: Upstream Oil and Gas Industry Investment in Nominal Terms and Adjusted for Cost Inflation

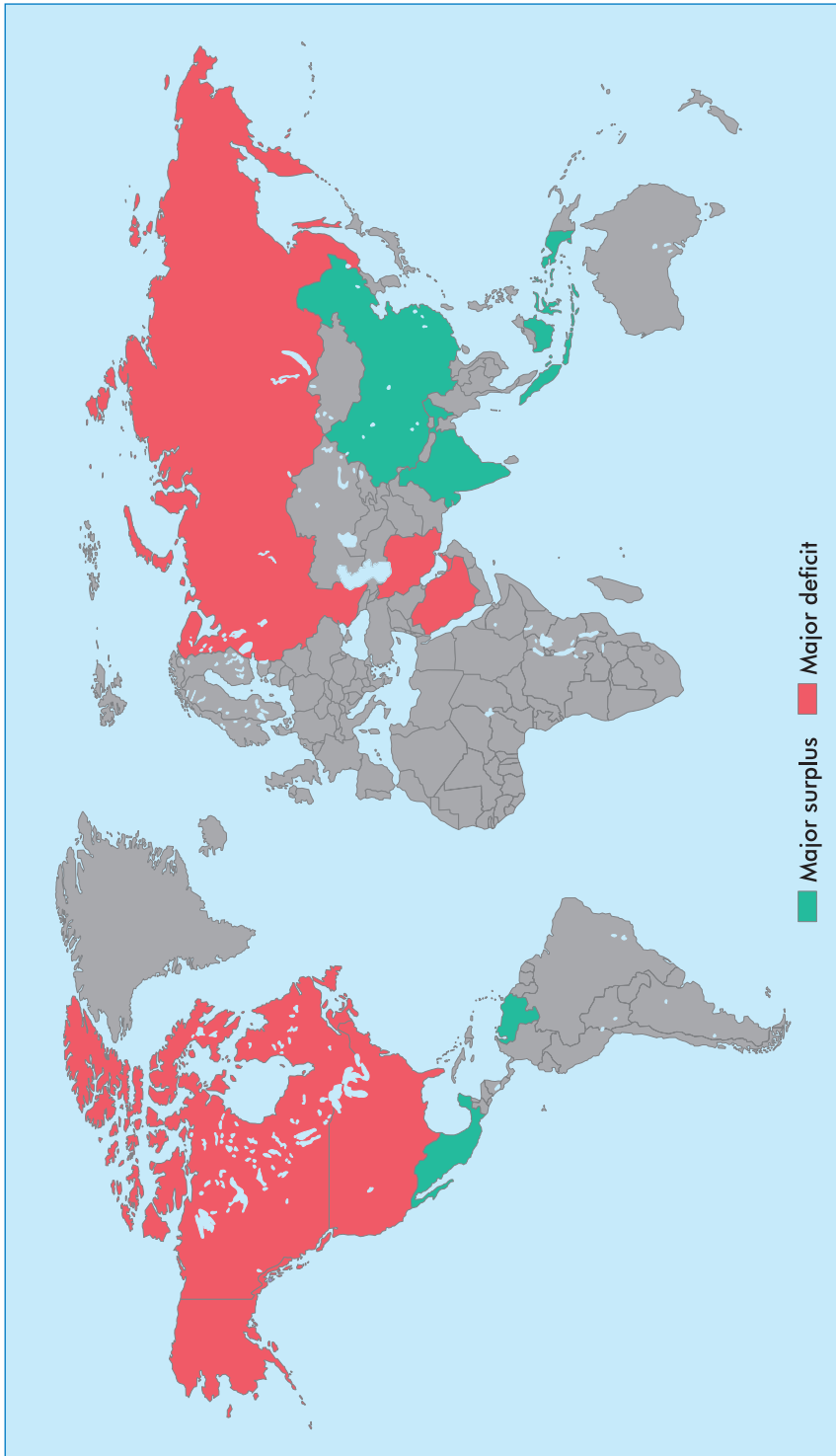


Source: IEA database and analysis.

Increased exploration and development activity is stretching the industry labour force to its limits. A 2005 benchmarking survey of 30 oil and gas companies and 115 universities estimates that the demand for petroleum-industry personnel will increase by around 7% per year for the next ten years.⁶ Demand for experienced, qualified personnel far outstrips current availability and there are regional shortages of petroleum geology and engineering university graduates. The biggest shortages of local graduates are in North America, the Middle East, Russia and other transition economies (Figure 12.11). Venezuela, Mexico, India, China and Indonesia are among the few countries with excess graduates in petroleum disciplines. Globally the supply should meet demand if all petro-technical graduates were to join the industry. A historically low intake of suitably qualified graduates into the industry is pushing up the average age of the workforce across all disciplines: it currently ranges from 40 to 50 years (Deloitte, 2005). A significant gap also exists between the supply of, and demand for, mid-career experienced oil industry personnel.

6. Private survey carried out by Schlumberger Business Consulting, the results of which were communicated to the IEA Secretariat.

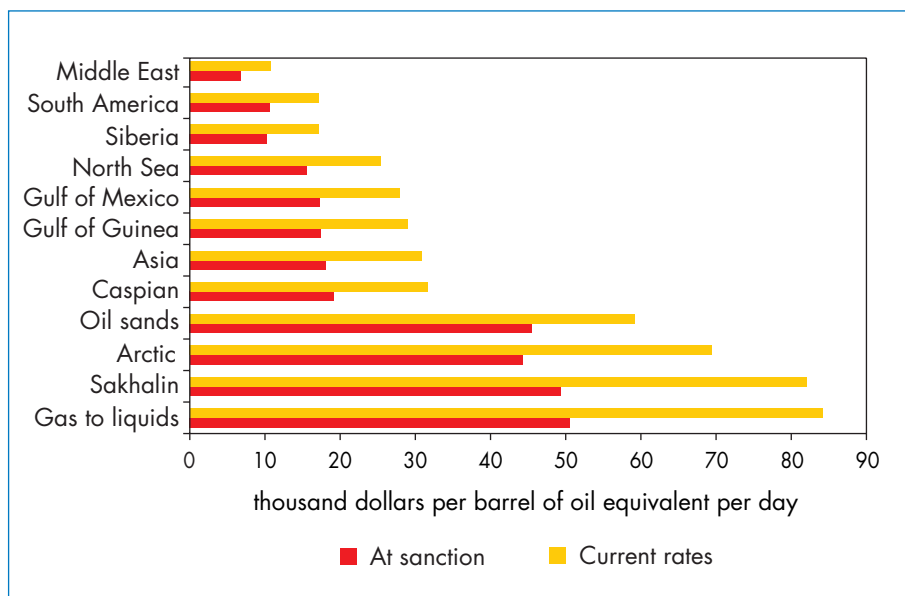
Figure 12.11: Availability of Petroleum-Industry Graduates by Region



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.
Source: Information provided to the IEA by Schlumberger Business Consulting.

The average capital cost of the capacity to produce each new barrel of oil equivalent per day due to come on stream in the period 2006-2010 is estimated at \$31 000. Costs vary considerably across regions. The most expensive are over \$60 000 and include oil sands (bitumen mining) and gas to liquids projects as well as projects based in Sakhalin and Arctic regions. By far the cheapest are in the Middle East, at a little over \$10 000 (Figure 12.12). In most cases, costs have risen sharply since the projects were sanctioned – especially in the Arctic regions and for the development of oil sands in Canada, where significant new infrastructure is needed.

Figure 12.12: Estimated Capital Intensity of Upstream Development Projects by Region, 2006-2010



Source: IEA database and analysis.

Implications for Oil and Gas Production Capacity

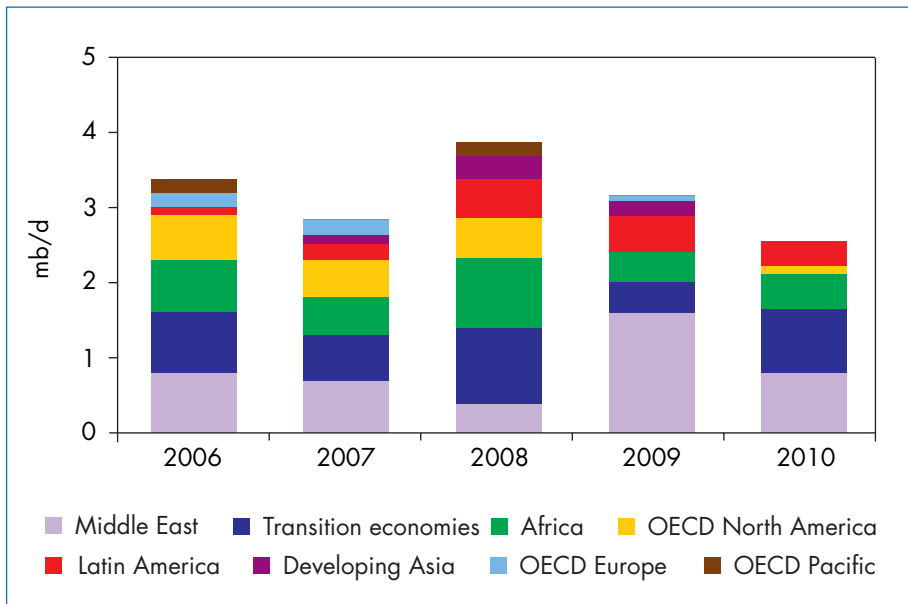
Of the more than 120 major upstream projects we analysed, 89 have been sanctioned, creating a minimum expected gross addition to oil production capacity of 12.7 mb/d by 2010. This increases to 15.4 mb/d with the addition of 23 planned projects (Table 12.2). Almost two-thirds of this capacity is expected to come on stream by 2008. The Middle East, transition economies

and Africa account for 70% of total additions to 2010 (Figure 12.13). Our separate review of the 40 oil and gas companies' production growth plans points to additional oil-production capacity of 15.9 mb/d by 2010.

Historically, slippage in the completion of projects is quite common and typically ranges from 5% to 20%. The probability of slippage is even more likely today due to shortages of equipment, materials and personnel. Of the 22 recently launched projects, 15 are currently encountering delays, averaging one-and-a-half years, while seven were ahead of schedule, by an average of four months. Two examples of major projects that are slipping behind schedule are Sakhalin-2 in Russia, which is delayed by at least a year because of the complexity of the project, the need for regulatory approvals and the environment, and Thunder Horse in the Gulf of Mexico, which is expected to be two-and-a-half years late, because of technical problems, notably faulty valves, which almost led to the capsizing of the de-manned floating platform when hit by Hurricane Dennis in 2005.

The biggest gross oil-production capacity additions between 2006 and 2010 will occur in the Middle East, totalling about 4.2 mb/d. Saudi Arabia accounts for most of this. Three major projects are currently under way there, which together will add approximately 2 mb/d of capacity. The Haradh development

Figure 12.13: Gross Oil Capacity Additions from New Sanctioned and Planned Projects by Region



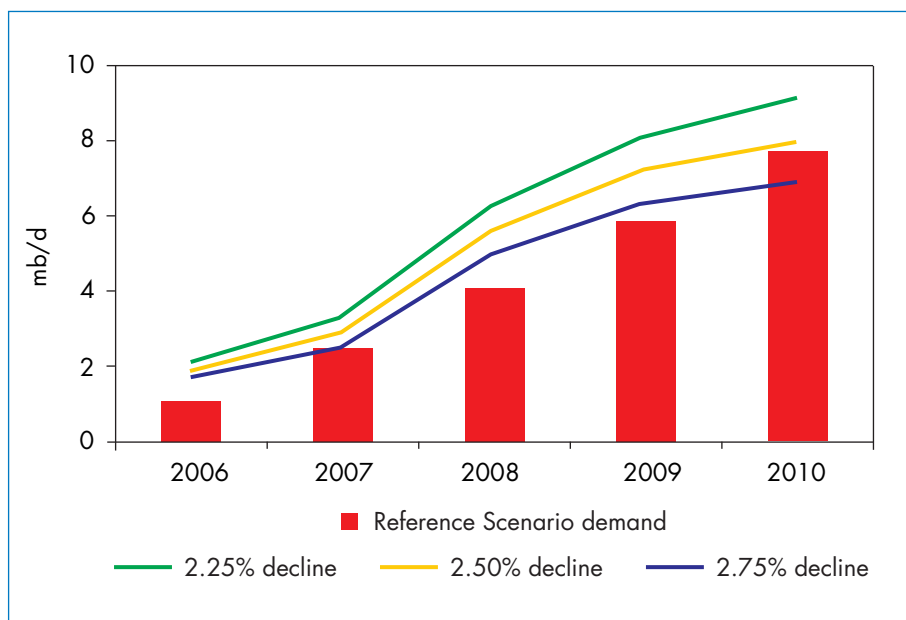
Source: IEA upstream project database.

was commissioned at the beginning of 2006, adding 300 kb/d. The mothballing of the light crude Khursaniyah field and the nearby Fahdili and Abu Hadriya fields are expected to be completed in 2007 and the expansion of the extra light crude Shaybah field is due on stream in 2008. The largest increment, of 1.2 mb/d, will come from the Khurais field – one of five onshore fields mothballed by Saudi Aramco in the early 1990s. Khurais, a satellite of Ghawar, will be developed in parallel with the offshore heavy crude Manifa field. Outside the Middle East, the largest increment in gross capacity will occur in Azerbaijan, where 1.2 mb/d will be added over the next four years to feed the recently opened Baku-Tbilisi-Ceyhan pipeline. Gross capacity additions in the three OECD regions will be small and will be significantly impacted by declines in production at existing fields, resulting in a low net capacity increase. A drop in crude oil capacity will be compensated by a rise in NGL and non-conventional capacity (in Canada).

While both our project-based projections and oil companies' production forecasts are of similar magnitude, they are not exhaustive and account for only a proportion of all the projects that will be implemented worldwide. To arrive at a world figure, we have analysed both data sets, to cross-check, calibrate and scale up our estimate of production-capacity additions by 2010. Using the share of the 40 companies surveyed in the upstream projects and their relative share of world oil production, an estimated world gross capacity addition of 21 mb/d was derived. This figure includes an extrapolation of capacity additions for the projects not involving the 40 companies surveyed. Assuming an average slippage rate of 10% compared with current estimated project completion times, which may be conservative in the current market environment, gross adjusted additions are over 2 mb/d lower, at under 19 mb/d.

These planned gross additions will be offset by declines in production from existing fields as reserves are depleted – even with continuous large-scale investments in those fields. Based on a global observed decline rate of 2.5% per year, the reduction in capacity at existing fields amounts to 10 mb/d between 2005 and 2010. The *net* increase in production capacity is, therefore, estimated at around 9 mb/d. The projected increase in oil demand in the Reference Scenario is 7.7 mb/d. So, if these projections prove accurate, spare crude oil production capacity, currently estimated at about 2 mb/d, would increase by 1.3 mb/d to 3.3 mb/d in the Reference Scenario. This increase might help to ease the tightness of crude oil markets over the next few years. However, an increase of just one-quarter of a per cent in the decline rate of existing fields would offset almost all of this additional spare capacity (Figure 12.14). A higher slippage rate than assumed here would also reduce the increase in spare capacity. In the Alternative Policy Scenario, world oil demand is projected to grow by 5.6 mb/d by 2010, which would have the effect of increasing spare capacity by 3.3 mb/d to 5.4 mb/d.

Figure 12.14: Cumulative Additions to Global Oil Demand and Net Oil Production Capacity Based on Observed Rates of Decline of Existing Production



Source: IEA database and analysis.

The spare capacity estimate of 3.3 mb/d to 5.4 mb/d is lower than the 4.9 mb/d to 6.8 mb/d range for 2010 published in the IEA's *Mid-Term Oil Market Report (MTOMR)* of July 2006. Differences in the approaches in this *Outlook* and the *MTOMR* result in these slightly different outcomes. While both methodologies produce similar results for firmly committed crude oil projects, the *MTOMR* accounts for exploration activity through 2010, to factor in any as yet unidentified projects. It allows for this by looking at reserves to production (RP) ratios in individual countries, adding small increments to countries where RP levels move to unusually high levels, while subtracting capacity where production profiles (based on firm projects) look unsustainable. On the other hand, this *Outlook* assumes that tightness in the oil-services sector and equipment and labour markets will prove a further constraint to existing or new projects in the period to 2010.

OPEC NGLs have also been modelled differently. The *MTOMR* looks closely at the firmly-committed liquids-extraction plans for OPEC countries alongside the gas-output projections in *WEO-2005*. Production of natural gas, and therefore NGLs, in *WEO-2006* has been revised downwards, reflecting

slower growth in global gas demand and the difficult investment and political climate in key countries. The next update of the *MTOMR* will assess whether, considering the current underutilisation of liquids in the gas stream, these changes to the gas flows will affect NGL extraction.

Gas production capacity is expected to rise even more rapidly than oil capacity, with just over 710 billion cubic metres per year of gas capacity due to be added worldwide in the five years to 2010.⁷ This figure should be considered a gross increase as it includes company plans for both the addition of production from new projects and increases from existing fields. Subtracting the estimated natural decline in production yields a net increase in capacity of 380 bcm/year. Our upstream project analysis suggests that at least 230 bcm/year of this increase will come from new fields currently under development (Table 12.2). Global gas demand is projected to increase by just over 400 bcm in the Reference Scenario between 2005 and 2010. This might suggest a tightening of gas markets to 2010. However, gas markets remain highly regionalised, so a global estimate gives little indication of the gas supply/demand balance in the main consuming markets. In addition, it is difficult to predict how much associated gas will be marketed, rather than reinjected or flared. In most OECD countries, indigenous production is close to plateau or already in decline, so that they will need to rely increasingly on imports to meet their gas needs (see Chapter 4 and IEA, 2006b).

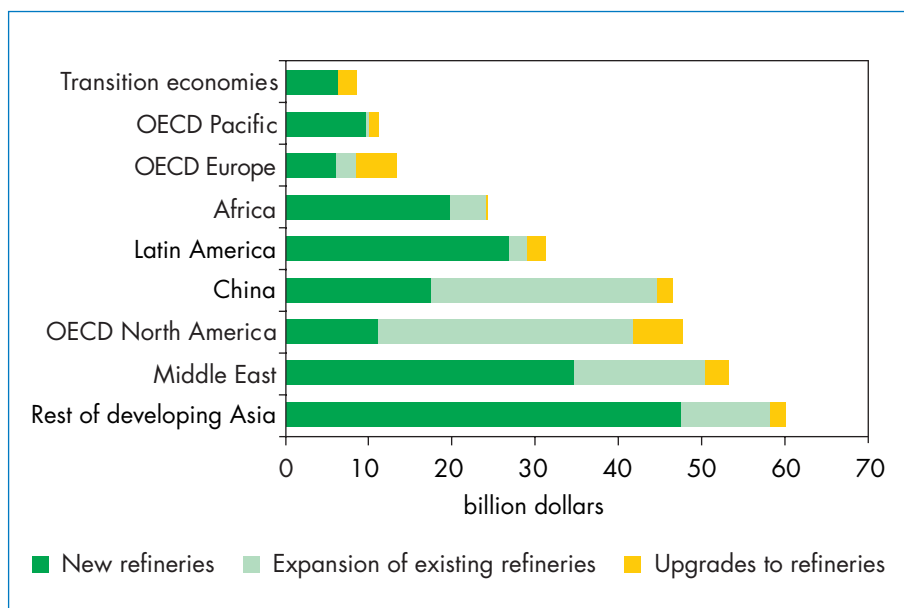
Oil Refining

Total refining industry investment has risen strongly since the start of the current decade. Capital spending reached an estimated \$51 billion in 2005 – up from \$34 billion in 2000. Industry spending plans point to continuing, but slightly more modest increases in the next five years, reaching \$62 billion in 2010. On average, spending will be \$60 billion per year in 2006-2010, compared with \$43 billion in 2001-2005. Just over 60%, or \$180 billion, of the total investment of \$298 billion during the five years to 2010 will be in new greenfield refineries, with the rest going to expansion projects (\$95 billion) and upgrading only (\$24 billion) at existing refineries (Figure 12.15).

The bulk of investment in both new and existing refineries will go to secondary processing units to improve the quality of finished products and increase the yield of light products and middle distillates. This will enable refiners to meet changes in the pattern of demand towards lighter products and to meet tighter product specifications, including lower maximum permitted sulphur content. Most new distillation capacity will be at greenfield refineries being built mainly

7. World gas production extrapolated from surveyed companies' gas production growth plans based on their share of world gas production.

Figure 12.15: World Oil Refinery Investment by Type, 2006-2010



Source: IEA database and analysis.

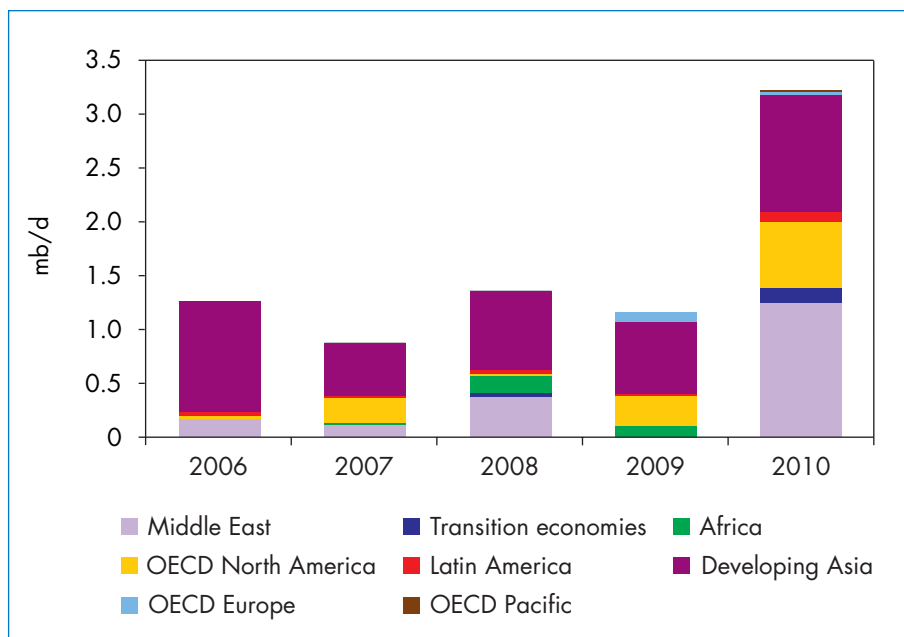
in developing countries. The Middle East and developing Asia will account for the lion's share of global investment in refining in 2006-2010.

We estimate that sanctioned and planned projects will add 7.8 mb/d of new distillation and upgrading capacity by 2010. The additions come on stream particularly at the end of the period and just after; a further 2.5 mb/d will be added in 2011 bringing the total distillation increase to 10.3 mb/d (IEA, 2006a). The biggest increases in capacity are planned for developing Asia – mainly China and India – and the Middle East (Figure 12.16). Virtually no new capacity will be added in OECD Europe or OECD Pacific, while there will be only a relatively modest increase in OECD North America.

Liquefied Natural Gas Facilities

There will be an unprecedented increase in capital spending on new LNG projects in the five years to 2010 and the biggest increase in capacity ever. A massive 167 million tonnes (226 bcm) per year of new liquefaction capacity is under construction or is planned to come on stream by 2010, involving about \$73 billion of investment. If all these projects come to fruition, capacity would almost double to 345 Mt/year. A further 60 million tonnes (82 bcm) of

Figure 12.16: World Oil Refinery Capacity Additions by Region, 2006-2010



Sources: IEA database and analysis; information obtained from Purvin and Gertz.

capacity, costing an additional \$26 billion, is proposed to come on stream by 2010 (Table 12.3). New LNG tankers on order exceed \$32 billion. Regasification plants will require another \$31 billion and are expected to add 328 bcm per year regasification capacity by 2010.

Close to half of the sanctioned and planned projects to increase liquefaction capacity in 2006-2010 will occur in the Middle East and North Africa. Qatar, already the world's largest LNG producer and exporter after Indonesia, will add more capacity than any other country, tripling capacity to 77 Mt/year by 2010. Australia and Nigeria are also planning to substantially increase their existing capacity. Angola, Equatorial Guinea, Norway and Yemen are expected to join the ranks of the LNG-exporting countries by the end of the decade. Iran, Peru, Russia and Venezuela have proposed LNG projects, but they are less likely to be completed before 2010.

The bulk of the planned increase in LNG production is destined for markets in Europe and North America. In the United States, fifteen regasification terminals had received planning approval from the Federal Energy Regulatory Commission as of 30 August 2006 and a further two terminals had been

Table 12.3: Natural Gas Liquefaction Plants to be Commissioned by 2010

Country	Operator	Project name	Status	Online	Capacity (Mt/year)	Cost (\$ million)
Algeria	Repsol & Gas Natural	Gassi Touil Arzew	Engineering	2009	4.0	2 100
Algeria	Sonatrach	Skikda Replacement	Engineering	2010	5.9	800
Angola	Sonangol, Chevron	Soyo	Engineering	2010	5.1	5 000
Australia	NW Shelf LNG	Karratha T5 NWS	Construction	2008	4.3	1 100
Australia	Chevron	Gorgon	Engineering	2009	10.1	1 100
Australia	Pluto LNG	Karratha	Proposed	2010	6.0	1 200
Australia	Woodside	Greater Sunrise	Proposed	2010	5.4	2 800
Australia	Inpex	Ichthys	Proposed	2010	4.0	1 200
Brunei	Brunei LNG (Shell)	Lumut (Brunei LNG)	Planned	2009	4.0	1 000
Egypt	ELNG	Idku T3 ELNG	Planned	2008	3.7	750
Equatorial Guinea	Marathon & GE Petrol	Bioko Island	Construction	2007	3.5	1 700
Indonesia	BP	Tangguh	Construction	2008	8.1	1 000
Indonesia	BP & Pertamina	Donggi	Planned	2009	7.1	1 000
Iran	NIGEC, Total	Assalayeh Pars LNG	Proposed	2009	8.9	2 000
Iran	NIGEC, Repsol Shell	Assalayeh Persian LNG	Proposed	2010	10.7	2 500
Nigeria	NNPC, ENI & Conoco	Brass River	Engineering	2009	10.1	2 000
Nigeria	NLNG (Shell, Agip & Elf)	Bonny Train 7	Engineering	2010	8.0	4 000
Nigeria	ExxonMobil, Chevron & ConocoPhillips	West Niger Delta	Planned	2010	20.0	4 000
Norway	Statoil	Snohvit	Construction	2007	5.5	2 700
Peru	Total, Repsol, BG & Semptra	Pacific LNG	Proposed	2009	5.9	5 000
Peru	Hunt Oil & SK	Pampa Melchorita LNG	Proposed	2010	4.0	2 000

Table 12.3: Natural Gas Liquefaction Plants to be Commissioned by 2010 (Continued)

Country	Operator	Project name	Status	Online	Capacity (Mt/year)	Cost (\$ million)
Qatar	Qatargas II (QPC, ExxonMobil & Total)	Ras Laffan (T1 & T2)	Construction	2008	15.6	7 600
Qatar	RasGas (QPC & ExxonMobil)	Ras Laffan (T5)	Construction	2008	4.8	2 000
Qatar	Qatargas III (QPC & ConocoPhillips)	Ras Laffan (T3)	Engineering	2009	7.5	6 500
Qatar	Qatargas IV (QPC & Shell)	Ras Laffan (T4)	Engineering	2010	7.9	7 000
Qatar	RasGas (QPC & ExxonMobil)	Ras Laffan (T6 & T7)	Construction	2010	15.8	7 000
Russia	Shell Mitsubishi Mitsui	Sakhalin II	Construction	2008	9.6	12 000
Russia	Tambei LNG	Yamal	Proposed	2010	3.5	1 500
Trinidad & Tobago	Atlantic LNG	Pomit Fortin (T5 & T6)	Proposed	2010	6.0	5 000
Venezuela	PDVSA Shell	Mariscal Sucre LNG	Proposed	2010	4.8	2 700
Yemen	Yemen LNG	Bal Haf Yemen LNG	Construction	2009	6.2	3 000
Planned, engineering and construction					166.8	73 350
Proposed					59.2	25 900
World					226.0	99 250

Note: Proposed projects could slip beyond 2010 but are included here for the sake of completeness.
Source: IEA database and analysis.

approved by the US Maritime Administration.⁸ However, construction work has begun on only five of them. Another three projects have been approved in Canada and three in Mexico. Terminals now being built will add about 65 bcm/year of capacity by 2010 to the 60 bcm/year of capacity at the five existing terminals, all of which are located in the United States (IEA, 2006b). If all the approved projects go ahead, capacity could exceed 200 bcm/year. In Europe, 16 new terminals are under construction or planned at a total cost of \$10 billion. Capacity is expected to increase by 110 bcm per year by 2010.

Investment in the LNG chain has been stimulated by high gas prices in the main consuming regions, dwindling indigenous production and rising demand. Despite the very large amounts of capital needed for each project, the interval between LNG project approval and completion has generally been short compared to pipeline projects of comparable size, which generally take a decade. In part, this is explained by the fact that most projects have been led by international oil companies with access to ample finance, strong credit ratings and extensive experience of managing large-scale energy projects. Falling costs relative to pipelines have boosted interest in new LNG projects. However, rising engineering, procurement and contracting costs – caused in part by the recent surge in demand for related services and materials – are already leading to delays in sanctioning and completing some projects, and to decisions not to proceed with others. Nonetheless, even with escalating costs, the number of proposed LNG projects continues to grow more rapidly than the number of long-distance pipeline projects.

Gas-to-Liquids Plants

A small but growing proportion of total oil and gas industry investment is going to gas-to-liquids plants, which convert natural gas into high-quality oil products. There are three existing GTL plants in operation: Shell's 15-kb/d plant in Bintulu Malaysia, PetroSA's 25-kb/d plant in Mossel, South Africa and the joint venture 34-kb/d Oryx plant built by Qatar Petroleum (QP), Chevron and Sasol in Qatar, which was commissioned in early 2006. Another 34-kb/d plant is being built by Chevron and the Nigerian National Petroleum Corporation at Escarvos in Nigeria. Two further GTL plants are at an advanced planning stage: the Shell/QP Pearl plant in Qatar, with a final capacity of 140 kb/d, and Sonatrach's 36-kb/d plant at Tinhert in Algeria. Other GTL plants planned for Qatar are on hold pending a review of the optimal extraction policy for the giant North Field. The GTL projects currently under

8. Information on the status of North American LNG projects is available from the FERC website (www.ferc.gov).

construction or just recently completed involve investment of \$24 billion and promise to add 280 kb/d by 2010. This makes GTL the most capital-intensive of all the oil production projects, at almost \$84 000 per barrel of capacity.

Oil Sands and Extra-Heavy Oil

Of the 120 largest upstream projects under development or planned for completion between 2006 and 2010, ten involve the development of non-conventional oil reserves. Eight are based on oil sands in Canada and two on extra-heavy oil in Venezuela. In Canada, oil is extracted by opencast mining of bitumen when the oil sands are close to surface and by *in-situ* recovery using steam injection and production wells when the oil sands are too deep to mine. Combined investment amounts to \$35 billion and will add just over 1 mb/d of oil production capacity by 2010. There are a further 17 projects under consideration, with the potential to add another 2 mb/d by 2015 at an estimated cost of \$44 billion. The investment required for oil-sands mining operations amounts to some \$45 000 to \$60 000 per barrel, while *in-situ* projects cost roughly half that (see Chapter 3). Several projects in Canada may be delayed because of a lack of manpower and of road and rail infrastructure to provide access to the remote oil-sand deposits. The plans of some operators include air strips to fly workers to and from the mines. The refining industry in the two countries is estimated to be investing a total of \$200 million in 50 separate upgrading projects to process the additional volumes of extra-heavy crude oil and bitumen feedstock that will flow from the new upstream projects.

Investment Beyond the Current Decade

Unlike our longer-term analysis of the production and investment outlook presented in Chapter 3 (oil) and Chapter 4 (gas), the analysis of near-term investment prospects set out in this chapter has been limited to the period to 2010 (for reasons described in Box 12.1). However, this analysis has provided us with several observations about investment challenges in the next decade, which we present below for completeness.

In summary, our near-term analysis points to a significant increase in investment through to 2010, though a significant part of this is the result of cost inflation across the industry. Companies based in the OECD countries are expected to continue to provide the bulk of capital spending, with most of it going to countries outside both the OECD and OPEC. We estimate that, unless project-slippage rates or production-decline rates worsen significantly, global crude oil production capacity is likely to outstrip the growth in oil demand in the Reference Scenario as well as in the Alternative Policy Scenario. However, any spare production capacity the industry builds up in the next five years could be quickly offset if real capital spending is not raised further into the next decade and beyond.

The prospects for investment and production-capacity additions beyond the present decade are more challenging and will require further increases in investment. Increased exploration investment is required to appraise reserves for the next wave of development projects. The future projects in the “golden triangle” of deep-water basins, encompassing the Gulf of Mexico, Nigeria and Angola, are likely to be more numerous but smaller. Such fields will have higher development costs per barrel, requiring higher investment than current large projects, which benefit from economies of scale. Existing drilling rigs and 90 others under construction are expected to be kept busy well into the next decade, as exploration activity and the number of development projects increase.

On the other hand, there are a number of new large unexplored basins, notably in the Russian Arctic, deep-water Caspian and offshore Greenland, that could yield significant new discoveries and underpin a new wave of large-scale developments. The harsh climate and the lack of existing infrastructure will mean higher capital investment and, assuming successful exploration and appraisal, production of oil or gas in these areas is unlikely to start much before 2020, given their remoteness.

In the Middle East, Iraq is under-explored, but security would have to improve greatly to permit the large-scale involvement of international companies. Even when the safety of company personnel can be assured, investment is likely to be focused initially on the re-development of existing fields, rather than exploration and the development of new fields. The international oil and gas companies are uniquely equipped to undertake complex, large-scale projects, thanks to their project-management skills, their access to advanced technology and their financial resources. But opportunities for them to invest remain limited because of government policy, civil conflict or geopolitical risks – especially in the Middle East, Russia, Africa and South America. The willingness and ability of national oil companies to develop reserves are in many cases very uncertain.⁹

Combating production decline at existing fields remains a top priority for the industry. Production from some of the super-giant oilfields that have been in production for decades, including Ghawar, the world’s largest field, will plateau within the next decade or so. Increasingly large investments in enhanced oil recovery will be needed here, as elsewhere in mature basins, raising production costs. Fields developed more recently using advanced technology to maximise output and recovery are expected to remain at plateau for shorter periods and then decline more rapidly than earlier fields.

9. See Chapter 3 for a discussion of the main uncertainties surrounding oil investment in the longer term, including the Deferred Investment Case in OPEC countries.

TABLE OF CONTENTS

PART A
**THE
REFERENCE
SCENARIO**

PART B
**THE
ALTERNATIVE
POLICY
SCENARIO**

PART C
**FOCUS
ON KEY TOPICS**

ANNEXES

KEY ASSUMPTIONS	1
GLOBAL ENERGY TRENDS	2
OIL MARKET OUTLOOK	3
GAS MARKET OUTLOOK	4
COAL MARKET OUTLOOK	5
POWER SECTOR OUTLOOK	6
MAPPING A NEW ENERGY FUTURE	7
ASSESSING THE COST-EFFECTIVENESS OF ALTERNATIVE POLICIES	8
DEEPENING THE ANALYSIS: RESULTS BY SECTOR	9
GETTING TO AND GOING BEYOND THE ALTERNATIVE POLICY SCENARIO	10
THE IMPACT OF HIGHER ENERGY PRICES	11
CURRENT TRENDS IN OIL AND GAS INVESTMENT	12
PROSPECTS FOR NUCLEAR POWER	13
THE OUTLOOK FOR BIOFUELS	14
ENERGY FOR COOKING IN DEVELOPING COUNTRIES	15
FOCUS ON BRAZIL	16
ANNEXES	

Foreword	3
Acknowledgements	5
List of Figures	22
List of Tables	29
List of Boxes	33
Summary and Conclusions	37
Introduction	49

Part A: The Reference Scenario **51**

1	Key Assumptions	53
	Highlights	53
	Government Policies and Measures	54
	Population	55
	Macroeconomic Factors	57
	Energy Prices	59
	Technological Developments	63
2	Global Energy Trends	65
	Highlights	65
	Demand	66
	<i>Primary Energy Mix</i>	66
	<i>Regional Trends</i>	68
	<i>Sectoral Trends</i>	70
	Energy Production and Trade	71
	<i>Resources and Production Prospects</i>	71
	<i>Inter-Regional Trade</i>	73
	<i>Investment in Energy Infrastructure</i>	75
	Energy-Related CO ₂ Emissions	78
3	Oil Market Outlook	85
	Highlights	85
	Demand	86
	Supply	88
	<i>Resources and Reserves</i>	88
	<i>Production</i>	91
	<i>Trade</i>	100
	<i>Investment</i>	102
	<i>Implications of Deferred Upstream Investment</i>	107

4	Gas Market Outlook	111
	Highlights	111
	Demand	112
	Supply	114
	<i>Resources and Reserves</i>	114
	<i>Production</i>	115
	<i>Inter-Regional Trade</i>	117
	<i>Investment</i>	121
5	Coal Market Outlook	125
	Highlights	125
	Demand	126
	Reserves and Production	127
	Inter-Regional Trade	131
	Coal Supply Costs and Investment	133
6	Power Sector Outlook	137
	Highlights	137
	Electricity Demand Outlook	138
	Power Generation Outlook	139
	<i>Energy-Related CO₂ Emissions from Power Generation</i>	144
	<i>The Economics of New Power Plants</i>	145
	<i>Capacity Requirements and Investment Outlook</i>	147
	<i>Power Generation Investment Trends in the OECD</i>	150
	<i>Investment Trends in Developing Countries</i>	153
	Part B: The Alternative Policy Scenario	159
7	Mapping a New Energy Future	161
	Highlights	161
	Background	162
	<i>Why an Alternative Policy Scenario?</i>	162
	<i>Methodology</i>	164
	<i>Policy Assumptions</i>	165
	<i>Energy Prices and Macroeconomic Assumptions</i>	170
	<i>Technological Developments</i>	170
	Global Energy Trends	173
	<i>Primary and Final Energy Mix</i>	173
	<i>Energy Intensity</i>	177
	<i>Investment and Fuel Expenditures</i>	178
	Oil Markets	178
	<i>Demand</i>	178

<i>Supply</i>	179
<i>Inter-Regional Trade</i>	181
Gas Markets	182
<i>Demand</i>	182
<i>Production and Trade</i>	183
Coal Markets	184
<i>Demand</i>	184
<i>Production and Trade</i>	186
Energy Security in Importing Countries	186
Energy-Related CO ₂ Emissions	188

8

Assessing the Cost-Effectiveness of Alternative Policies	193
Highlights	193
Investment in Energy-Supply Infrastructure and End-Use Equipment	194
<i>Overview</i>	194
<i>Investment along the Electricity Chain</i>	196
<i>Demand-Side Investment</i>	198
<i>Supply-Side Investment</i>	202
Implications for Energy Import Bills and Export Revenues	203
Implications for Consumers	205
<i>Barriers to Investment in End-Use Energy Efficiency</i>	210

9

Deepening the Analysis: Results by Sector	213
Highlights	213
Power Generation	214
<i>Summary of Results</i>	214
<i>Electricity Mix</i>	216
<i>Policy Assumptions and Effects</i>	221
Transport	222
<i>Summary of Results</i>	222
<i>Road Transport</i>	224
<i>Policy Assumptions and Effects</i>	224
<i>Aviation</i>	231
Industry	234
<i>Summary of Results</i>	234
<i>Policy Assumptions and Effects</i>	237
Residential and Services Sectors	241
<i>Summary of Results</i>	241
<i>Policy Overview</i>	246

10	Getting to and Going Beyond the Alternative Policy Scenario	249
	Highlights	249
	Making the Alternative Policy Scenario a Reality	250
	<i>Identifying Policy Priorities</i>	250
	<i>Hurdles to Policy Adoption and Implementation</i>	253
	Going Beyond the Alternative Policy Scenario	256
	<i>Achieving the BAPS Goal</i>	256
	<i>Implications for Energy Security</i>	262
	Beyond 2030: the Need for a Technology Shift	262
	 Part C: Focus on Key Topics	 267
11	The Impact of Higher Energy Prices	269
	Highlights	269
	Introduction	270
	Energy Price Trends and Relationships	270
	<i>International Prices</i>	270
	<i>Final Prices to End Users</i>	275
	<i>Quantifying Energy Subsidies</i>	277
	Impact of Higher Energy Prices on Demand	282
	<i>Energy Demand Trends since Prices Started Rising</i>	282
	<i>Responsiveness of Energy Demand to Price Changes</i>	283
	<i>Explaining Recent Trends in Energy Demand</i>	289
	<i>Price Sensitivity Analysis</i>	295
	Macroeconomic Impact of Higher Energy Prices	297
	<i>How Higher Energy Prices Affect the Macroeconomy</i>	297
	<i>Quantifying the Recent Shift in the Terms of Trade</i>	299
	<i>Simulating the Macroeconomic Effects of Higher Energy Prices</i>	301
	<i>Explaining Macroeconomic Resilience to Higher Energy Prices</i>	306
	Energy Policy Implications	313
12	Current Trends in Oil and Gas Investment	315
	Highlights	315
	Overview	316
	Exploration and Development	321
	<i>Investment Trends</i>	321
	<i>Impact of Cost Inflation on Upstream Investment</i>	327
	<i>Implications for Oil and Gas Production Capacity</i>	331
	Oil Refining	335
	Liquefied Natural Gas Facilities	336
	Gas-to-Liquids Plants	340
	Oil Sands and Extra-Heavy Oil	341
	Investment beyond the Current Decade	341

Prospects for Nuclear Power	343
Highlights	343
Current Status of Nuclear Power	344
<i>Renewed Interest in Nuclear Power</i>	344
<i>Nuclear Power Today</i>	346
<i>Historical Development</i>	348
Policy Overview	351
<i>Nuclear Power Generation</i>	351
<i>Nuclear Fuel and Waste Management</i>	356
<i>Proliferation and International Conventions</i>	357
Outlook for Nuclear Power	360
<i>Reference Scenario</i>	361
<i>Alternative Policy Scenario</i>	361
Nuclear Power Economics in Competitive Markets	364
<i>Generating Costs under Different Discount Rate Assumptions</i>	364
<i>Sensitivity Analysis of Nuclear Power Generating Costs</i>	368
<i>Other Factors Influencing the Generating Cost of Nuclear Power</i>	371
<i>Financing Nuclear Power Plants</i>	374
Nuclear Fuel Outlook	376
<i>Demand for Uranium</i>	376
<i>Uranium Resources</i>	377
<i>Uranium Production</i>	380
<i>Uranium Prices and Investment in Exploration and Production</i>	381
Policy Issues	382

The Outlook for Biofuels	385
Highlights	385
Current Status of Biofuels Production and Use	386
<i>Market Overview</i>	386
<i>Ethanol</i>	388
<i>Biodiesel</i>	389
<i>The Environmental Impact of Biofuels</i>	391
Prospects for Biofuels Production and Use	394
<i>Summary of Projections to 2030</i>	394
<i>Regional Trends</i>	400
Key Drivers and Uncertainties	405
<i>Technology and Production Costs</i>	405
<i>Biomass and Land Needs for Biofuels Production</i>	412
<i>International Trade in Biofuels</i>	416

15	Energy for Cooking in Developing Countries	419
	Highlights	419
	Household Energy Use in Developing Countries	420
	Harmful Effects of Current Cooking Fuels and Technologies	424
	<i>Health</i>	424
	<i>Environment</i>	427
	<i>The Burden of Fuel Collection</i>	428
	Outlook for Household Biomass Use in Developing Countries	431
	<i>Improving the Way Biomass is Used</i>	433
	<i>Modern Cooking Fuels and Stoves</i>	433
	<i>Quantifying the Potential Impact of Modern Cooking Fuels and Stoves</i>	435
	Policy Implications	440
16	Focus on Brazil	447
	Highlights	447
	Overview	448
	The Political and Economic Outlook	449
	<i>The Political Scene</i>	449
	<i>The National Economy</i>	450
	Recent Trends and Developments in the Energy Sector	452
	Outlook for Energy Demand	454
	<i>Reference Scenario</i>	455
	<i>Alternative Policy Scenario</i>	462
	Outlook for Supply	464
	<i>Oil</i>	464
	<i>Natural Gas</i>	471
	<i>Coal</i>	474
	<i>Biomass</i>	474
	<i>Power and Heat</i>	479
	Environmental Issues	484
	Investment	486
	ANNEXES	489
	Annex A Tables for Reference and Alternative Policy Scenario Projections	491
	Annex B Electricity Access	565
	Annex C Abbreviations and Definitions	573
	Annex D Acronyms	581
	Annex E References	585

List of Figures

Chapter 1. Key Assumptions

1.1	World Population by Region	57
1.2	Growth in Real GDP Per Capita by Region	60
1.3	Average IEA Crude Oil Import Price in the Reference Scenario	62
1.4	Crude Oil Price and Differentials to Oil Product Prices	62

Chapter 2. Global Energy Trends

2.1	World Primary Energy Demand by Fuel in the Reference Scenario	67
2.2	World Primary Energy Demand by Region in the Reference Scenario	70
2.3	Incremental World Primary Energy Demand by Sector in the Reference Scenario, 2004-2030	71
2.4	Fuel Shares in World Final Energy Demand in the Reference Scenario	72
2.5	Share of Inter-Regional Trade in World Primary Demand by Fossil Fuel in the Reference Scenario	74
2.6	Cumulative Investment in Energy Infrastructure in the Reference Scenario by Fuel and Activity, 2005-2030	78
2.7	Increase in Energy-Related CO ₂ Emissions by Region	80
2.8	World Energy-Related CO ₂ Emissions by Fuel in the Reference Scenario	81
2.9	Energy-Related CO ₂ Emissions by Region in the Reference Scenario	82
2.10	Average Annual Growth in World Energy-Related CO ₂ Emissions and Primary Energy Demand in the Reference Scenario	82

Chapter 3. Oil Market Outlook

3.1	Incremental World Oil Demand by Region and Sector in the Reference Scenario, 2004-2030	87
3.2	Top Twenty Countries' Proven Oil Reserves, end-2005	89
3.3	Undiscovered Oil Resources and New Wildcat Wells Drilled, 1996-2005	90
3.4	Cumulative Oil and Gas Discoveries and New Wildcat Wells	91
3.5	World Oil Supply by Source	95
3.6	Non-OPEC Conventional Crude Oil and NGLs Production	95
3.7	Gravity and Sulphur Content of Selected Crude Oils, 2005	96
3.8	Non-Conventional Oil Production and Related Natural Gas Needs in Canada	100
3.9	Net Oil Exports in the Reference Scenario	101
3.10	Cumulative Oil Investment by Activity in the Reference Scenario, 2005-2030	103
3.11	Cumulative Investment in Oil Refining by Region, 2005-2030	103

3.12	Access to World Proven Oil Reserves, end-2005	105
3.13	Reduction in World Oil Demand and OPEC Market Share	108
3.14	World Oil Production in the Deferred Investment Case Compared with the Reference Scenario	109

Chapter 4. Gas Market Outlook

4.1	World Primary Natural Gas Demand by Sector in the Reference Scenario	113
4.2	Proven Gas Reserves and Production by Region, 2005	115
4.3	Natural Gas Production by Region in the Reference Scenario	116
4.4	Main Net Inter-Regional Natural Gas Trade Flows in the Reference Scenario, 2004 and 2030	119
4.5	World Inter-Regional Natural Gas Trade by Type in the Reference Scenario	121
4.6	Cumulative Investment in Gas-Supply Infrastructure by Region and Activity in the Reference Scenario, 2005-2030	122

Chapter 5. Coal Market Outlook

5.1	Share of Power Generation in Total Coal Consumption by Region in the Reference Scenario	128
5.2	Proven Coal Reserves by Country	129
5.3	Global Coal Production by Type in the Reference Scenario	131
5.4	Net Inter-Regional Trade in Hard Coal in the Reference Scenario	133
5.5	Indicative Supply Costs for Internationally Traded Steam Coal	134
5.6	Structure of Steam Coal Supply Costs for Major Exporting Countries	135

Chapter 6. Power Sector Outlook

6.1	World Electricity Demand by Region in the Reference Scenario	138
6.2	Average Annual Growth in Electricity Demand by Region in the Reference Scenario	139
6.3	World Incremental Electricity Generation by Fuel in the Reference Scenario	140
6.4	Incremental Coal-Fired Electricity Generation by Region in the Reference Scenario, 2004-2030	141
6.5	World Hydropower Potential	143
6.6	Increase in Power-Sector CO ₂ Emissions by Fuel in the Reference Scenario, 2004-2030	144
6.7	Electricity Generating Cost Ranges of Baseload Technologies	145
6.8	Impact of Capacity Factor on Generating Costs	146

6.9	Impact of Carbon Value on Generating Costs	147
6.10	Cumulative Power-Sector Investment by Region in the Reference Scenario, 2005-2030	149
6.11	Cumulative Power-Sector Investment by Type in the Reference Scenario, 2005-2030	150
6.12	European Generation Margins	151
6.13	US Capacity Reserve Margins	152
6.14	Japan Power-Sector Investment, 1998 to 2003	153
6.15	Private Investment in Electricity Infrastructure in Developing Countries, 1990-2004	154
6.16	Cumulative Private Investment in Electricity Infrastructure in Developing Countries, 1990-2004	155
6.17	Population without Electricity, 2005	156

Chapter 7. Mapping a New Energy Future

7.1	Years Saved in the Alternative Policy Scenario in Meeting the Levels of Deployment of the Reference Scenario in 2030	172
7.2	World Primary Energy Demand in the Reference and Alternative Policy Scenarios	174
7.3	Incremental Demand and Savings in Fossil Fuels in the Alternative Policy Scenario, 2004-2030	174
7.4	Incremental Non-Fossil Fuel Demand in the Reference and Alternative Policy Scenarios, 2004-2030	176
7.5	Change in Primary Energy Intensity by Region in the Reference and Alternative Policy Scenarios, 2004-2030	177
7.6	Oil Supply in the Alternative Policy Scenario	180
7.7	Increase in Net Oil Imports in Selected Importing Regions in the Alternative Policy Scenario	182
7.8	Natural Gas Imports in Selected Importing Regions in the Reference and Alternative Policy Scenarios	184
7.9	Coal Demand in the Reference and Alternative Policy Scenarios	185
7.10	Change in Oil and Gas Imports in the Reference and Alternative Policy Scenarios, 2004-2030	187
7.11	Energy-Related CO ₂ Emissions by Region in the Alternative Policy Scenario	189
7.12	Change in Energy-Related CO ₂ Emissions by Region in the Reference and Alternative Policy Scenarios, 2004-2030	189
7.13	Energy-Related CO ₂ Emissions Savings by Region in the Alternative Policy Scenario, 2030	191
7.14	Global Savings in CO ₂ Emissions in the Alternative Policy Scenario Compared with the Reference Scenario	192

Chapter 8. Assessing the Cost-Effectiveness of Alternative Policies

8.1	Change in Cumulative Demand- and Supply-Side Investment in the Alternative Policy Scenario, 2005-2030	195
8.2	Demand-Side Investment and Final Energy Savings by Region in the Alternative Policy Scenario	200
8.3	Cumulative Global Investment in Electricity-Supply Infrastructure by Scenario, 2005-2030	202
8.4	Investment in Fossil-Fuel Supply in the Reference and Alternative Policy Scenarios, 2005-2030	203
8.5	Oil and Gas Export Revenues in the Middle East and North Africa in the Reference and Alternative Policy Scenarios	205
8.6	Indicative Average Payback Period of Selected Policies in the Alternative Policy Scenario by Region	206
8.7	Change in End-Use Electricity Investment and in Consumers' Electricity Bills in the Alternative Policy Scenario, 2005-2030	207
8.8	Change in End-Use Investment in Transport and Consumers' Fuel Bills in the Alternative Policy Scenario, 2005-2030	209
8.9	World Bank Investment in Energy by Sector, 1990-2005	211

Chapter 9. Deepening the Analysis: Results by Sector

9.1	Reduction in Electricity Generation in the Alternative Policy Scenario by Region, 2030	214
9.2	Global Fuel Shares in Electricity Generation	215
9.3	Reduction in Coal-Fired Generation by Region in the Alternative Policy Scenario	217
9.4	Share of Nuclear Power in Electricity Generation by Region in the Alternative Policy Scenario	218
9.5	Shares of non-Hydro Renewable Energy in Electricity Generation by Region in the Alternative Policy Scenario	219
9.6	Investment Costs of Renewables-Based Power-Generation Technologies in the Alternative Policy Scenario, 2004 and 2030	220
9.7	CO ₂ Emissions per kWh of Electricity Generated in the Reference and Alternative Policy Scenarios	220
9.8	World Transport Oil Demand in the Alternative Policy Scenario and Savings Compared with the Reference Scenario by Source	223
9.9	Road Transport Demand in the Reference and Alternative Policy Scenarios	225
9.10	World On-Road Passenger Light-Duty Vehicle Stock	229
9.11	New Vehicle Sales by Region, 2005-2030	230
9.12	Technology Shares in New Light-Duty Vehicles Sales in the Reference and Alternative Policy Scenarios	231

9.13	Growth in Road and Aviation Oil Consumption in the Reference Scenario	232
9.14	World Aviation CO ₂ Emissions	234
9.15	Change in Industrial Energy Demand by Region and Sector in the Alternative Policy Scenario, 2030	236
9.16	Change in Final Energy Consumption in the Residential and Services Sectors in the Alternative Policy Scenario by Fuel, 2030	242
9.17	Change in Electricity Demand in the Residential and Services Sectors in the Alternative Policy Scenario by Use, 2030	243

Chapter 10. Getting to and Going Beyond the Alternative Policy Scenario

10.1	Cumulative Energy-Related CO ₂ Emissions in the Reference and Alternative Policy Scenarios, 2005-2030	251
10.2	Reduction in Energy-Related CO ₂ Emissions in the BAPS Case Compared with the Alternative Policy Scenario by Option	258
10.3	Fuel Mix in Power Generation in Different Scenarios	260
10.4	CO ₂ Intensity of Electricity Generation	261

Chapter 11. The Impact of Higher Energy Prices

11.1	Average IEA Crude Oil Import Price	271
11.2	Average Crude Oil Import Prices by Region in Real Terms and Local Currencies	272
11.3	Average IEA Crude Oil and Natural Gas Import Prices	274
11.4	Average IEA Crude Oil and Coal Import Prices	275
11.5	Change in Real Energy End-Use Prices by Region and Fuel, 1999-2005	276
11.6	Change in Average Annual IEA Crude Oil Import Price and Road Fuel Prices in Ten Largest Oil-Consuming Countries, 1999-2005	277
11.7	Economic Value of Energy Subsidies in non-OECD Countries, 2005	280
11.8	Increase in World Primary Oil Demand by Region	284
11.9	Increase in Natural Gas Demand by Region	284
11.10	The Link between Fuel Price and Demand	285
11.11	Crude Oil Price Elasticities of Road Transport Oil Demand versus the Share of Tax in the Pump Price	288
11.12	World Oil Demand and Real GDP	290
11.13	World Oil Demand and Real GDP Per Capita	291
11.14	Share of Transport Sector in Primary Oil Consumption in the Reference and Alternative Policy Scenarios	292
11.15	World Stationary Final Fossil Fuel Demand and Real GDP Per Capita	294

11.16	World Electricity Demand and Real GDP Per Capita	295
11.17	Change in Primary Oil Demand in the High Energy Prices Case by Region and Sector Compared with the Reference Scenario, 2030	297
11.18	Oil-Import Intensity by Region	300
11.19	Increase in the Net Oil and Gas Import Bill in 2005 over 2002	301
11.20	Real GDP Growth by Region	307
11.21	Commodity Price Indices	308
11.22	Current Account Balance in Selected Countries/Regions	309
11.23	Current Account Balances of the United States, China and Oil Exporters	310

Chapter 12. Current Trends in Oil and Gas Investment

12.1	Total Oil and Gas Industry Investment, 2000-2010	317
12.2	Total Oil and Gas Industry Investment by Sector	320
12.3	Oil and Gas Industry Investment by Type of Company	321
12.4	Investment in Oil and Gas Exploration and Development	322
12.5	Upstream Investment by Activity, 2000-2010	323
12.6	Sanctioned and Planned Project Investment on New Oil and Gas Fields by Region, 2006-2010	323
12.7	Oil and Gas Exploration Investment	326
12.8	New Oil and Gas Project Investment by Source and Destination, 2006-2010	327
12.9	Active Drilling Rigs and Offshore Drilling Rigs under Construction, 1997-2006	328
12.10	Upstream Oil and Gas Industry Investment in Nominal Terms and Adjusted for Cost Inflation	329
12.11	Availability of Petroleum-Industry Graduates by Region	330
12.12	Estimated Capital Intensity of Upstream Development Projects by Region, 2006-2010	331
12.13	Gross Oil Capacity Additions from New Sanctioned and Planned Projects by Region	332
12.14	Cumulative Additions to Global Oil Demand and Net Oil Production Capacity Based on Observed Rates of Decline of Existing Production	334
12.15	World Oil Refinery Investment by Type, 2006-2010	336
12.16	World Oil Refinery Capacity Additions by Region, 2006-2010	337

Chapter 13. Prospects for Nuclear Power

13.1	Power Sector CO ₂ Emissions per kWh and Shares of Nuclear Power and Renewables in Selected Countries, 2004	345
13.2	Historical World Nuclear Capacity Additions	349

13.3	Shares of Nuclear Power in Electricity Generation by Region	350
13.4	Increases in Average Nuclear Capacity Factors, 1991-2005	350
13.5	World Nuclear Capacity in the Reference and Alternative Policy Scenarios	360
13.6	Share of Nuclear Power in Total Electricity Generation in the Alternative Policy Scenario	363
13.7	Electricity Generating Costs in the Low Discount Rate Case	367
13.8	Electricity Generating Costs in the High Discount Rate Case	368
13.9	Comparison of Nuclear, Coal and CCGT Generating Costs under Different Coal and Gas Prices	369
13.10	Impact of a 50% Increase in Fuel Price on Generating Costs	370
13.11	Impact of CO ₂ Price on Generating Costs	370
13.12:	Construction Time of Existing Nuclear Power Plants	373
13.13	Identified Uranium Resources in Top Twenty Countries	378
13.14	Uranium Resources versus Cumulative Uranium Demand	379
13.15	World Uranium Production Capability and Reactor Requirements in the Reference and Alternative Policy Scenarios	381
13.16	Uranium Oxide Spot Prices and Exploration Expenditures	382

Chapter 14. The Outlook for Biofuels

14.1	Share of Biofuels in Total Road-Fuel Consumption in Energy Terms by Country, 2004	388
14.2	World Ethanol Production	390
14.3	World Biodiesel Production	391
14.4	Share of Biofuels in Road-Transport Fuel Consumption in Energy Terms	396
14.5	Share of Ethanol in Total Biofuels Consumption in Energy Terms in Brazil, the European Union and the United States in the Reference Scenario	396
14.6	Biofuels Consumption in Selected EU Countries	403
14.7	Biofuel Production Costs versus Gasoline and Diesel Prices	406
14.8	Production Costs of Ethanol in Brazil, the European Union and the United States	407
14.9	Production Costs of Biodiesel in the European Union and the United States	408

Chapter 15. Energy for Cooking in Developing Countries

15.1	Share of Traditional Biomass in Residential Consumption by Country	423
15.2	Primary Energy Source for Cooking in Households in India and Botswana	424

15.3	Annual Deaths Worldwide by Cause	425
15.4	Deaths per Year Caused by Indoor Air Pollution, by WHO region	426
15.5	Woodfuel Supply and Demand Balance in East Africa	429
15.6	Distance Travelled to Collect Fuelwood in Rural Tanzania	430
15.7	Additional LPG Demand Associated with Switching Compared with World Oil Demand	437
15.8	Comparison of Average Annual Cost of LPG Fuel and Technology, 2007-2015, with Other Annual Allocations of Resources	439
15.9	Saudi Aramco Contract LPG Price	441
15.10	Residential Biomass Consumption and LPG Retail Price in Brazil	442

Chapter 16. Focus on Brazil

16.1	Primary Fuel Mix, 1980 and 2004	454
16.2	Oil Import Intensity in Brazil	456
16.3	Passenger Car Stock in Brazil in the Reference and Alternative Policy Scenarios	457
16.4	Industrial Energy Intensity in Selected Regions, 1970-2030	458
16.5	Primary Energy Demand in the Reference and Alternative Policy Scenarios in Brazil	459
16.6	Residential and Services Energy Demand in the Reference and Alternative Policy Scenarios	463
16.7	Brazil's Proven Reserves by Date of Discovery	465
16.8	Oil and Gas Fields and Related Infrastructure in Brazil	466
16.9	Brazil's Oil Balance in the Reference Scenario	468
16.10	Brazil's Crude Oil Production by Source in the Reference Scenario	470
16.11	Natural Gas Balance in Brazil in the Reference Scenario	472
16.12	Biofuels Penetration in the Road-Transport Sector in Brazil in the Reference and Alternative Policy Scenarios, 2004-2030	475
16.13	Planned Infrastructural Developments for Ethanol in Brazil	478
16.14	Power Generating Capacity in Brazil in the Reference Scenario	483
16.15	Brazil's Energy-Related CO ₂ Emissions in the Reference and Alternative Policy Scenarios	485
16.16	Brazil's Cumulative Investment in Energy-Supply Infrastructure in the Reference Scenario, 2005-2030	486

List of Tables

Chapter 1. Key Assumptions

1.1	World Population Growth	56
1.2	World Real GDP Growth	59
1.3	Fossil-Fuel Price Assumptions in the Reference Scenario	61

Chapter 2. Global Energy Trends

2.1	World Primary Energy Demand in the Reference Scenario	66
2.2	Net Energy Imports by Major Region	74
2.3	Cumulative Investment in Energy-Supply Infrastructure in the Reference Scenario, 2005-2030	77
2.4	World Energy-Related CO ₂ Emissions by Sector in the Reference Scenario	80
2.5	World Energy-Related CO ₂ Emission Indicators by Region in the Reference Scenario	83

Chapter 3. Oil Market Outlook

3.1	World Primary Oil Demand	86
3.2	World Oil Supply	92
3.3	Major New Oil-Sands Projects and Expansions in Canada	98
3.4	Oil-Import Dependence by Major Importing Region in the Reference Scenario	101

Chapter 4. Gas Market Outlook

4.1	World Primary Natural Gas Demand in the Reference Scenario	112
4.2	Inter-Regional Natural Gas Trade by Region in the Reference Scenario	118

Chapter 5. Coal Market Outlook

5.1	World Coal Demand	127
5.2	World Coal Production in the Reference Scenario	130
5.3	Hard Coal Net Inter-Regional Trade in the Reference Scenario	132

Chapter 6. Power Sector Outlook

6.1	New Electricity Generating Capacity and Investment by Region in the Reference Scenario, 2005-2030	148
-----	---	-----

Chapter 7. Mapping a New Energy Future

7.1	Selected Policies Included in the Alternative Policy Scenario	168
7.2	World Energy Demand in the Alternative Policy Scenario	173
7.3	Final Energy Consumption in the Alternative Policy Scenario	177
7.4	World Oil Demand in the Alternative Policy Scenario	179
7.5	Net Imports in Main Importing Regions	181
7.6	World Primary Natural Gas Demand in the Alternative Policy Scenario	183

Chapter 8. Assessing the Cost-Effectiveness of Alternative Policies

8.1	Change in Cumulative Electricity Investment in the Alternative Policy Scenario, 2005-2030	197
8.2	Additional Demand-Side Investment in the Alternative Policy Scenario, 2005-2030	198
8.3	Cumulative Oil and Gas Import Bills in Main Net Importing Regions by Scenario, 2005-2030	204

Chapter 9. Deepening the Analysis: Results by Sector

9.1	Electricity Generation and Electricity Intensity Growth Rates	215
9.2	Changes in Electricity-Generating Capacity Additions in the Alternative Policy Scenario, 2005-2030	217
9.3	Transport Energy Consumption and Related CO ₂ Emissions in the Alternative Policy Scenario	223
9.4	Key Selected Policies on Light-Duty Vehicle Fuel Economy in the Alternative Policy Scenario	227
9.5	Average On-Road Vehicle Fuel Efficiency for New Light-Duty Vehicles in the Reference and Alternative Policy Scenarios	228
9.6	Aviation Fuel Consumption and CO ₂ Emissions in the Alternative Policy Scenario	233
9.7	Change in Industrial Energy Consumption in the Alternative Policy Scenario, 2030	235
9.8	Energy Intensities in the Steel, Cement and Ammonia Industries in Selected Countries, 2004	238
9.9	Average Electricity Intensity of Primary Aluminium Production, 2004	239

Chapter 10. Getting to and Going Beyond the Alternative Policy Scenario

10.1	Most Effective Policies for Reducing Cumulative CO ₂ Emissions in 2030 in the Alternative Policy Scenario Compared with the Reference Scenario	252
10.2	Options for Emissions Reductions beyond 2030	263

Chapter 11. The Impact of Higher Energy Prices

11.1	Consumption Subsidy as Percentage of Final Energy Prices in non-OECD Countries, 2005	281
11.2	Change in Energy Demand by Fuel and Region	283
11.3	Crude Oil Price and Income Elasticities of Oil Demand Per Capita by Region	287

11.4	Change in Primary Energy Demand by Fuel and Region in the High Energy Prices Case Compared with the Reference Scenario	296
11.5	IMF Analysis of the Macroeconomic Impact of an Increase in the International Crude Oil Price to \$80 per Barrel	304
11.6	Macroeconomic Effects in EIA/IEA High Oil Price Case, 2007-2010	305
11.7	Estimated Impact of Higher Oil Prices since 2002 on Real GDP	306

Chapter 12. Current Trends in Oil and Gas Investment

12.1	Oil and Gas Production of Surveyed Companies by Type, 2005	319
12.2	Sanctioned and Planned Upstream Oil and Gas Developments for Completion in 2006-2010	324
12.3	Natural Gas Liquefaction Plants to be Commissioned by 2010	338

Chapter 13. Prospects for Nuclear Power

13.1	Key Nuclear Statistics, 2005	347
13.2	The Ten Largest Nuclear Operators in the World, 2005	348
13.3	Timeline Leading to the Construction of New Nuclear Reactors in the United States	351
13.4	Timeline Leading to the Construction of a New Nuclear Reactor in Finland	352
13.5	Timeline Leading to the Construction of a New Nuclear Reactor in France	353
13.6	Main Policies Related to Nuclear Power Plants in OECD Countries	354
13.7	Examples of High-Level Waste Disposal Strategies	358
13.8	Nuclear Capacity and Share of Nuclear Power in the Reference and Alternative Policy Scenarios	362
13.9	Main Cost and Technology Parameters of Plants Starting Commercial Operation in 2015	365
13.10	Summary of Financial Parameters	367
13.11	Average Estimated and Realised Investment Costs of Nuclear Power Plants by Year of Construction Start, 1966-1977	372
13.12	Total World Uranium Resources	377
13.13	World Uranium Production in Selected Countries, 2004	380
13.14	Summary of Nuclear Power Economics	383

Chapter 14. The Outlook for Biofuels

14.1	Biofuels Production by Country, 2005	387
14.2	World Biofuels Consumption by Scenario	394

14.3	Summary of Current Government Support Measures for Biofuels in Selected Countries/Regions	398
14.4	US Biofuels Production Capacity	402
14.5	Performance Characteristics of Biofuel Crops in Europe	410
14.6	Global Potential Biomass Energy Supply to 2050	415
14.7	Land Requirements for Biofuels Production	416

Chapter 15. Energy for Cooking in Developing Countries

15.1	People Relying on Biomass Resources as their Primary Fuel for Cooking, 2004	422
15.2	People Relying on Traditional Biomass	431
15.3	Costs and Characteristics of Selected Fuels	434
15.4	Additional Number of People Needing to Gain Access to Modern Fuels	436
15.5	Purchase Cost of LPG Stoves and Cylinders by Region	439
15.6	Benefits of Cleaner Cooking	440

Chapter 16. Focus on Brazil

16.1	Key Energy Indicators for Brazil	448
16.2	GDP and Population Growth Rates in Brazil in the Reference Scenario	451
16.3	Primary Energy Demand in the Reference Scenario in Brazil	455
16.4	Primary Energy Demand in the Alternative Policy Scenario in Brazil	459
16.5	Main Policies and Programmes Considered in the Alternative Policy Scenario	460
16.6	Change in Total Final Consumption in the Alternative Policy Scenario in 2030	463
16.7	Major Oilfields Currently in Production in Brazil	467
16.8	Brazil's Oil Production in the Reference Scenario	468
16.9	Electricity Generation Mix in Brazil in the Reference Scenario	481

List of Boxes

Chapter 1. Key Assumptions

1.1	Improvements to the Modelling Framework in <i>WEO-2006</i>	55
-----	--	----

Chapter 2. Global Energy Trends

2.1	Uncertainty Surrounding China's Energy Trends	69
2.2	Methodology for Projecting Energy Investment	76
2.3	Will Signatories to the Kyoto Protocol Respect their Greenhouse-Gas Emission-Limitation Commitments?	79

Chapter 3. Oil Market Outlook		
3.1	Canadian Oil-Sands Production Costs	99
Chapter 4. Gas Market Outlook		
4.1	LNG Set to Fill the Growing US Gas-Supply Gap	120
Chapter 5. Coal Market Outlook		
5.1	The Economics of Coal-to-Liquids Production	128
Chapter 6. Power Sector Outlook		
6.1	Prospects for Hydropower in Developing Countries	142
6.2:	Siting New Power Infrastructure	149
Chapter 7. Mapping a New Energy Future		
7.1	New Vehicle Fuel Economy in the United States	167
7.2	Current Status and Development of CO ₂ Capture and Storage Technology	171
Chapter 8. Assessing the Cost-Effectiveness of Alternative Policies		
8.1	Comparing Costs and Savings	194
8.2	Energy Efficiency Codes and Standards in China's Residential and Services Sectors	199
8.3	Energy Efficiency Project in Industry in China	201
8.4:	Energy Savings Programme in the UK Residential Sector	208
8.5:	Increasing Light-Duty Vehicle Efficiency	209
Chapter 9. Deepening the Analysis: Results by Sector		
9.1	The Efficiency of Energy Use in the Aluminium Industry	239
9.2	Improving the Energy Efficiency of Motor Systems	240
9.3:	Opportunities to Save Energy Through More Efficient Lighting	244
Chapter 11. The Impact of Higher Energy Prices		
11.1	Contractual Links between Oil and Gas Prices	273
11.2	Quantifying Global Energy Subsidies	278
Chapter 12. Current Trends in Oil and Gas Investment		
12.1	Analysis of Current Oil and Gas Investment Plans	317
Chapter 13. Prospects for Nuclear Power		
13.1	Recent Trends and Outlook for Nuclear Reactor Technology	363
13.2	Financing Finland's New Nuclear Reactor	375
13.3	Impact of Incentives in the US 2005 Energy Policy Act on Nuclear Power Generating Costs	376

Chapter 15. Energy for Cooking in Developing Countries		
15.1	The Brazilian Experience with LPG	432
15.2	Household Coal and Alternatives in China	435
15.3	The Role of Microfinance in Expanding the Use of Modern Fuels	443
Chapter 16. Focus on Brazil		
16.1	Regional Integration in South American Energy Markets	453
16.2	Petrobras' Development of Deep-water Crude Oil Production	469
16.3	Refinery Conversion with H-BIO Technology	470
16.4	Technological Developments in Sugar-Cane and Ethanol Production	477
16.5	Prospects for Renewable Energy-based Generation	482

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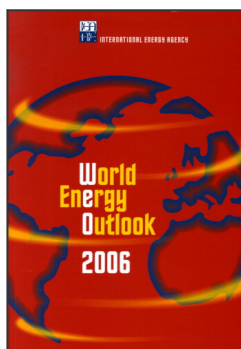
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