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.

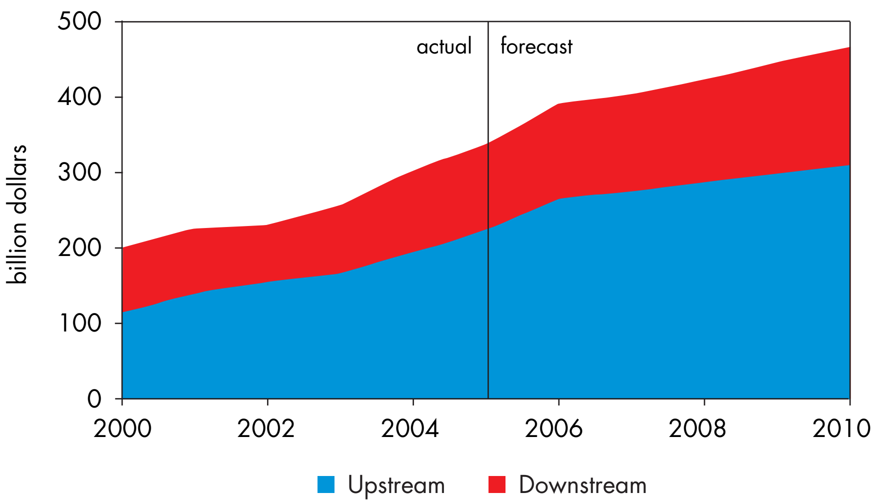
- The five years to 2010 will see an unprecedented increase in capital spending on new LNG projects. A massive 167 million tonnes (226 bcm) per year of new liquefaction capacity is under construction or planned to come on stream by 2010 at a cost of about $73 billion. World LNG capacity will almost double 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

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

Note: Data obtained from company reports and press statements.

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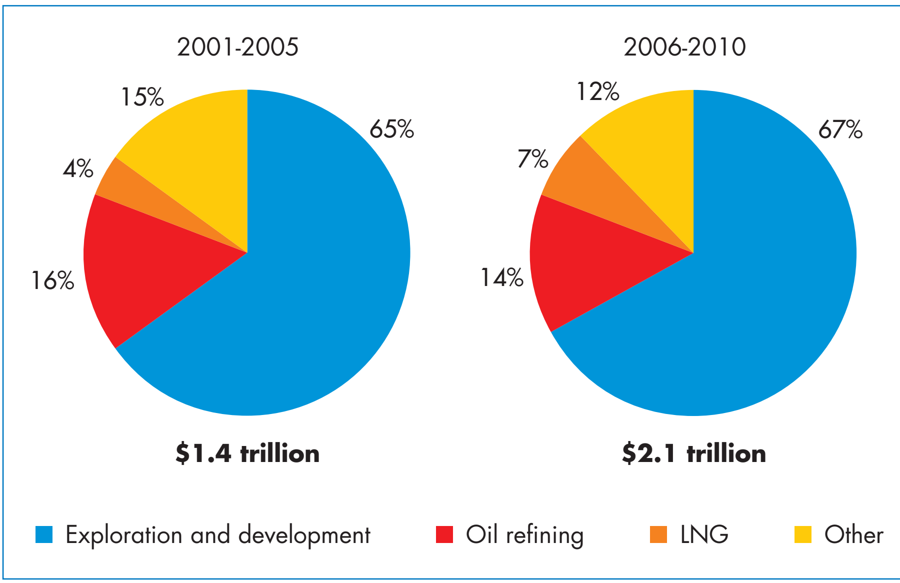
downstream activities, including GTL, pipelines, oil tankers, distribution and retailing (Figure 12.2). The shares of exploration and development and LNG projects are set to be higher in 2006-2010 than in the first half of the decade. Upstream spending would grow at an average annual rate of 6.7% between 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.

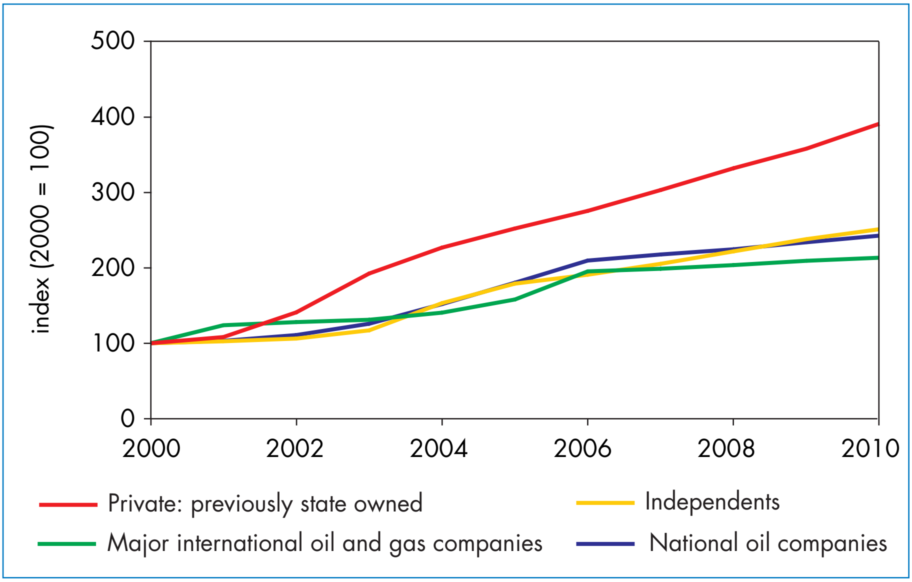
Figure 12.2: **Total Oil and Gas Industry Investment by Sector**



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**



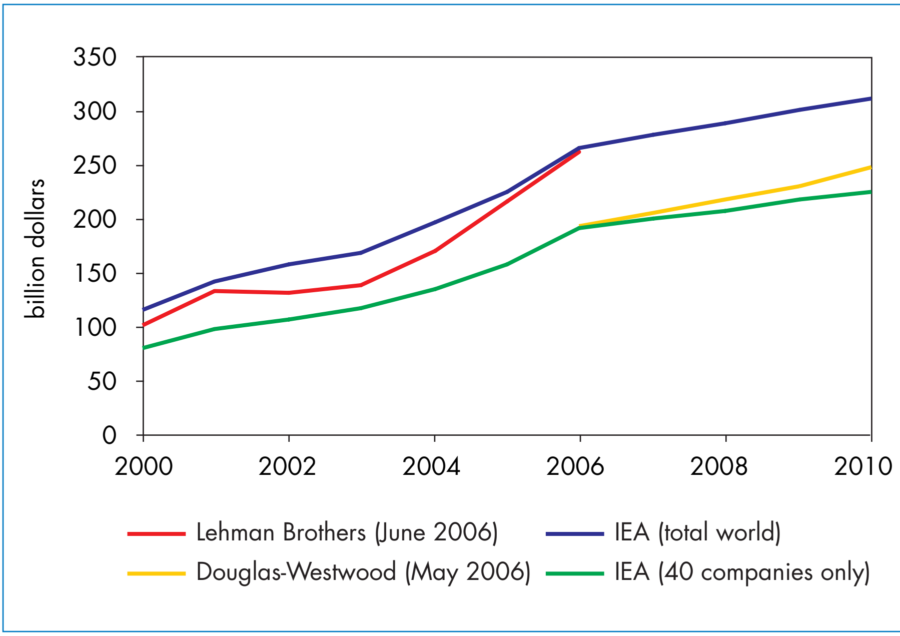
Note: See Table 12.1 for details of the breakdown by type of company.
Source: IEA databases and analysis.

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**

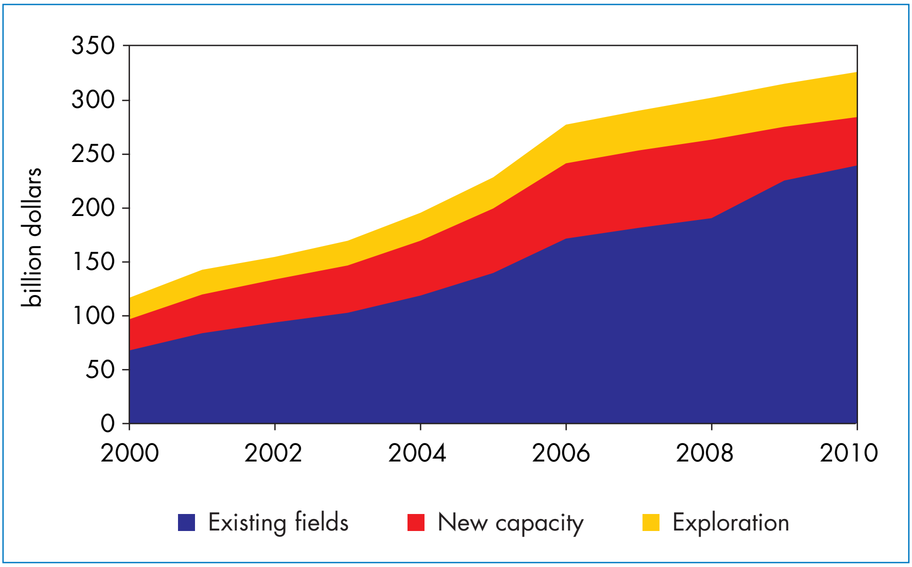


Source: IEA database and analysis; Lehman Brothers (2005); Douglas-Westwood (2006).

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).

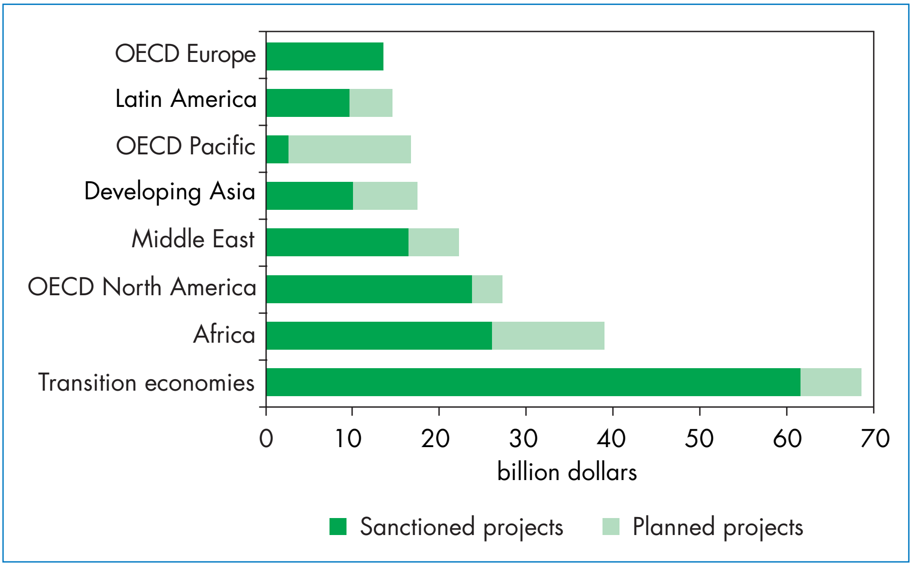
Almost all spending on new projects due to be on stream by 2010 has already been sanctioned, with many such projects already under development (Figure 12.6). More than half of the spending on new projects is going to Africa and the transition economies. Many of these projects are very large, involving 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.

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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
				Oil (kb/d)	Gas (bcm/year)	($ million)
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
Puguang	China	Sinopec	2008	–	4.0	4 500
Vankorskoye 2	Siberia	Rosneft	2008	328	–	4 500
Agbami	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

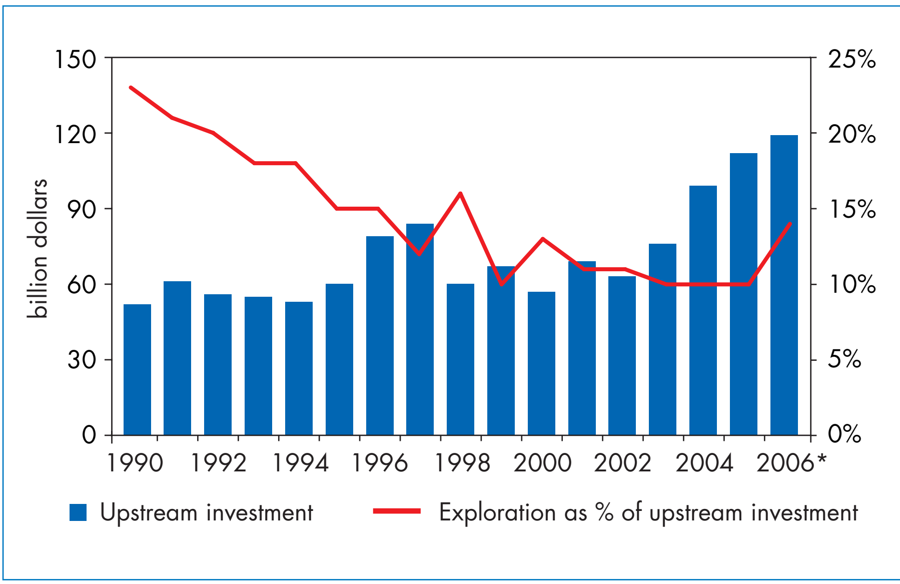
Table 12.2: **Sanctioned and Planned Upstream Oil and Gas Developments for Completion in 2006-2010** *(Continued)*

Project	Location	Operator	Completion date	Capacity addition Oil (kb/d)	Gas (bcm/year)	Total estimated capital cost ($ million)
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
Tyrihans	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.

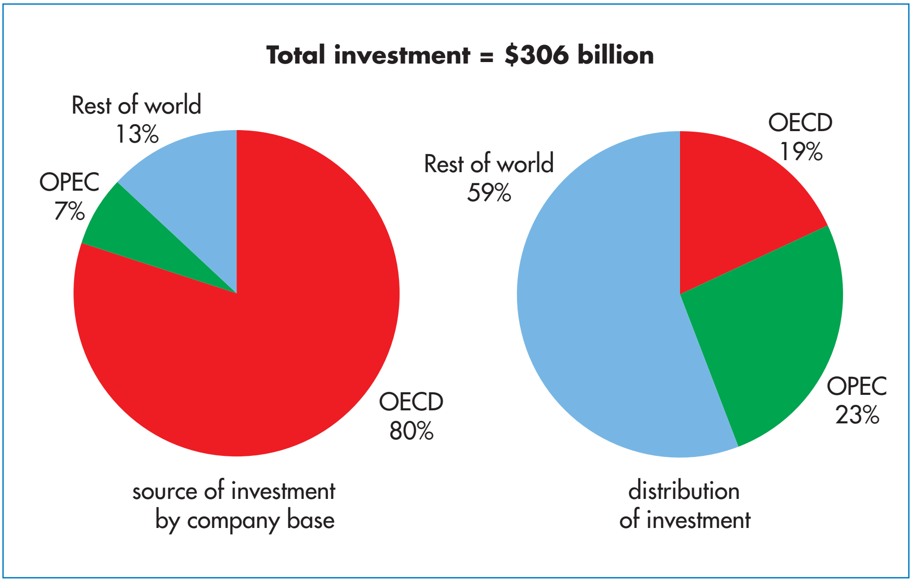
Figure 12.7: **Oil and Gas Exploration Investment**



* 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.

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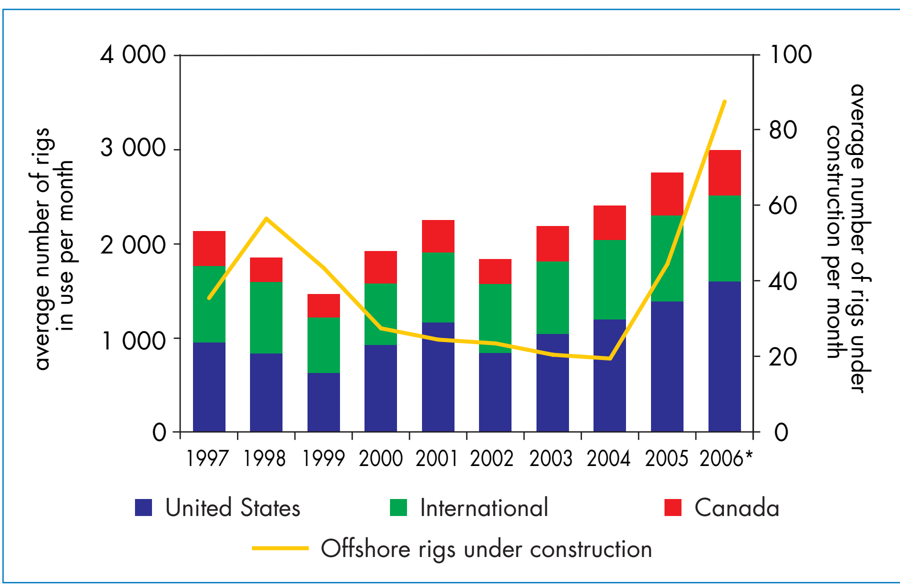
Impact of Cost Inflation on Upstream Investment

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**

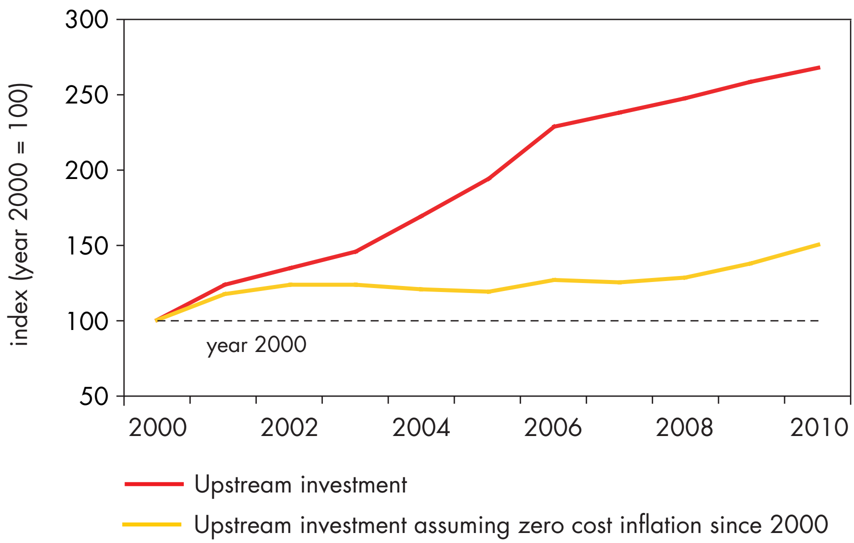


* To July.

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**

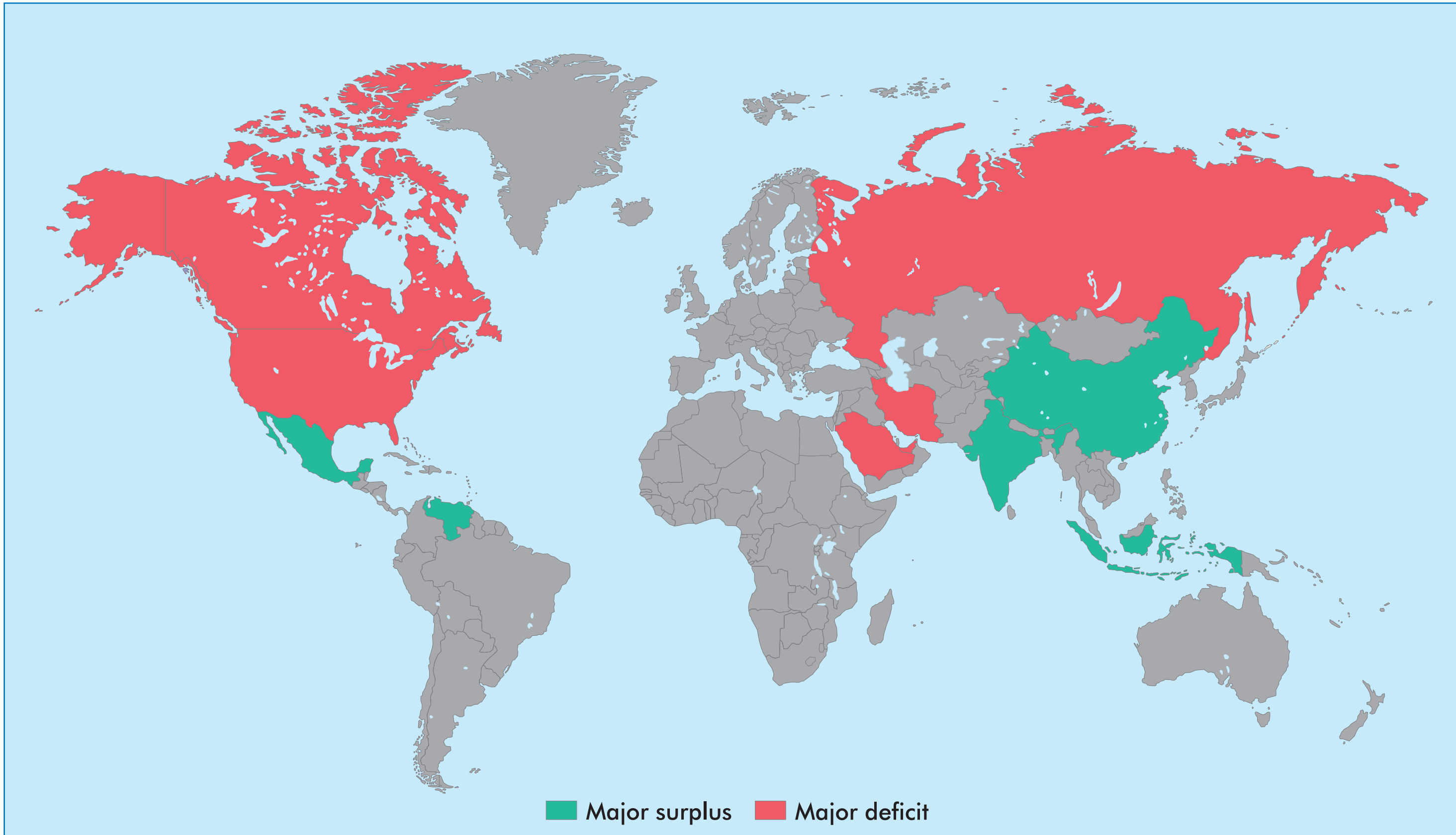


Source: IEA database and analysis.

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**

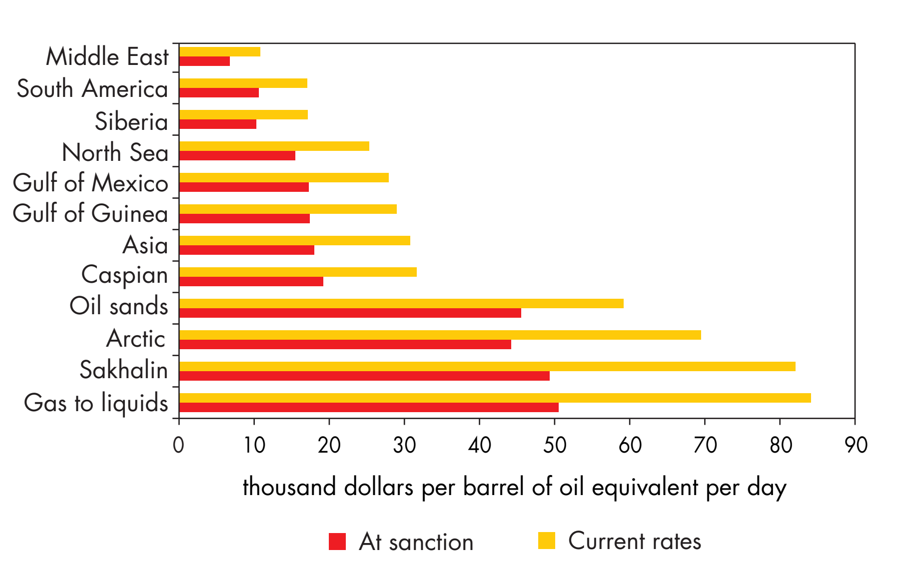


The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

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.

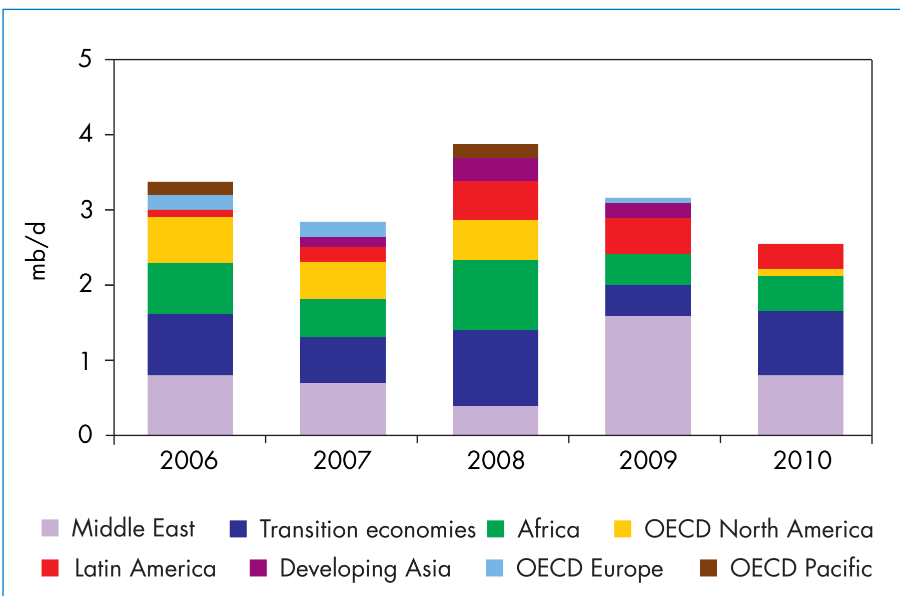
Implications for Oil and Gas Production Capacity

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 capsize 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**



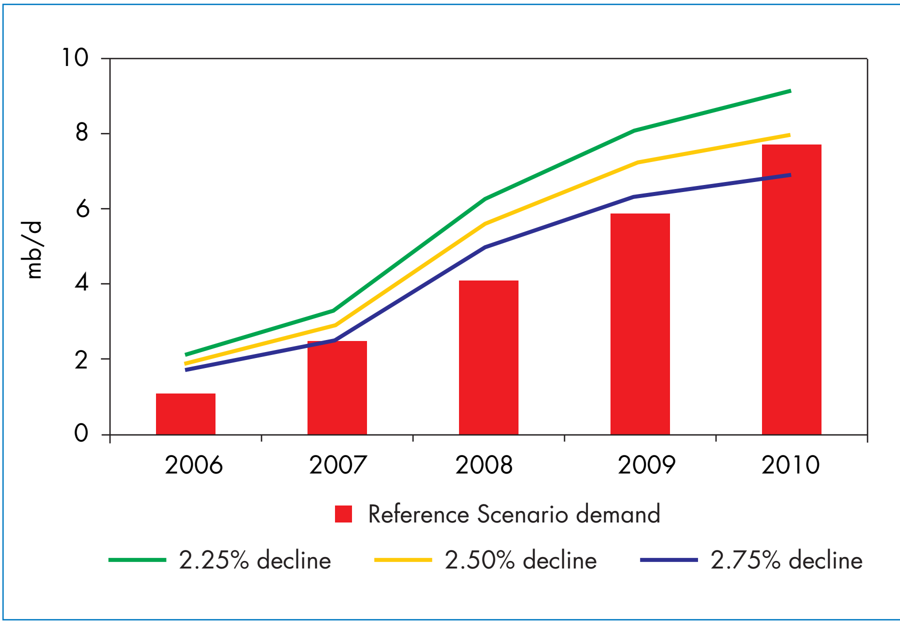
Source: IEA upstream project database.

was commissioned at the beginning of 2006, adding 300 kb/d. The de-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).

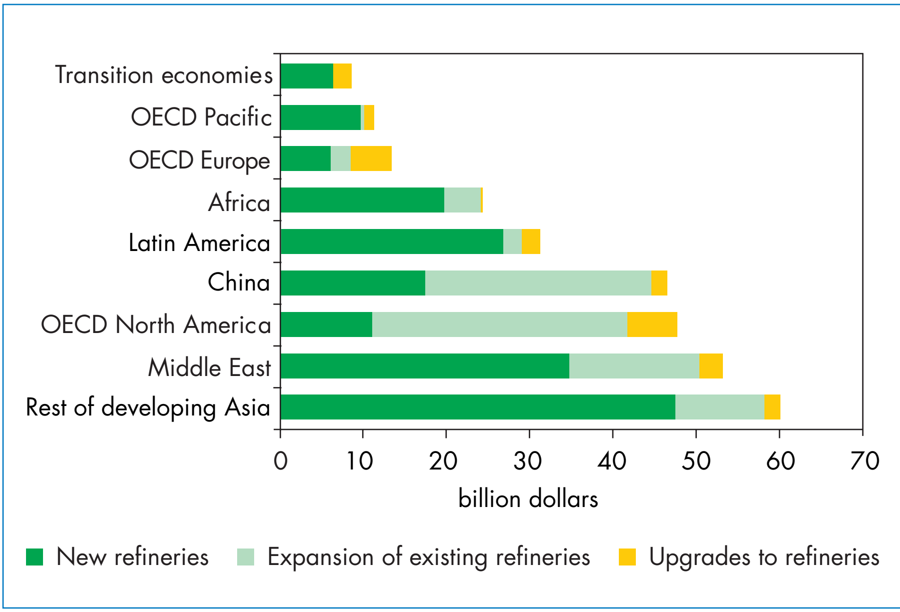
Oil Refining

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.

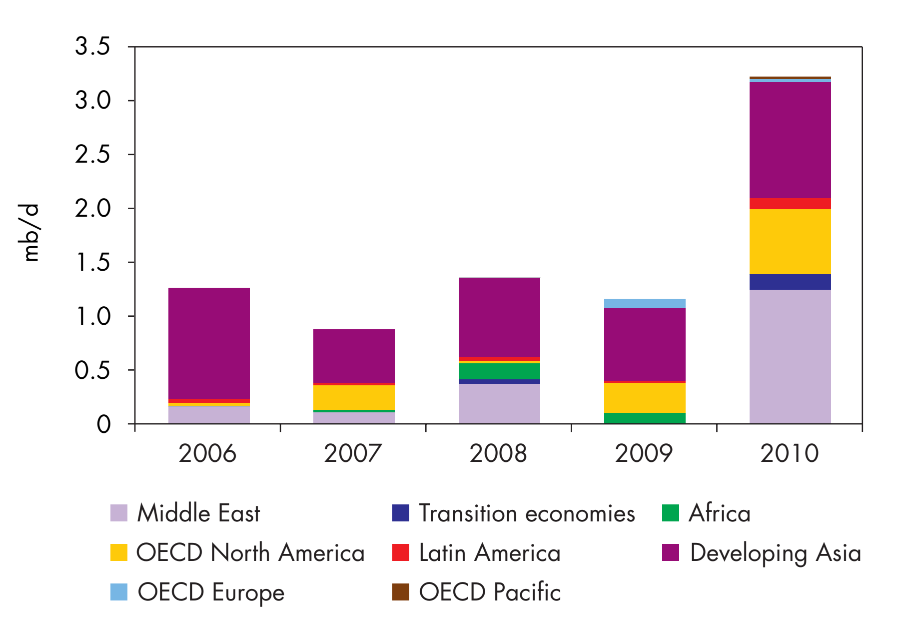
in developing countries. The Middle East and developing Asia will account for the lion's share of global investment in refining in 2006-2010.

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 & Sempra	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	1500
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.

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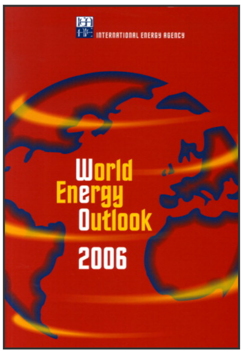

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