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Chapter 10

Field-by-Field Analysis of Oil Production

Is Decline Accelerating?

CHAPTER 10

FIELD-BY-FIELD ANALYSIS OF OIL PRODUCTION

Is decline accelerating?

H I G H L I G H T S

- The future rate of decline in output from producing oilfields as they mature is a critical determinant of the amount of new capacity and investment that will be needed globally to meet projected demand. A detailed field-by-field analysis of historical production trends reveals that the size of reserves and physiographic situation (onshore/offshore) are the main factors in explaining the shape of an oilfield's production profile. The larger the reserves, the lower the peak relative to reserves and the slower the decline once a field has come off plateau. Rates are also lower for onshore than offshore (especially deepwater) fields.
- Based on data for 580 of the world's largest fields that have passed their production peak, the observed decline rate – averaged across all fields and weighted by their production over their whole lives – is 5.1%. Decline rates are lowest for the biggest fields: they average 3.4% for super-giant fields, 6.5% for giant fields and 10.4% for large fields. The average rate of observed post-plateau decline, based on our data sub-set of 479 fields, is 5.8%.
- Observed decline rates vary markedly by region. Post-peak and post-plateau rates are lowest in the Middle East and highest in the North Sea. This reflects, to a large extent, differences in the average size of fields, which in turn is related to the extent to which overall reserves are depleted and their physiographic location. In general, observed decline rates are also higher the younger the field, mainly because these fields tend to be smaller and are more often found offshore. Investment and production policies also affect decline rates, especially in OPEC countries.
- The average size of the fields analysed is significantly larger than that of all the fields in the world, as our database contains all the super-giant fields and most of the giant fields. The decline rates for the fields not included in our dataset are, on average, likely to be at least as high as for the large fields in our database. On this basis, we estimate that the average production-weighted observed decline rate worldwide is 6.7% for post-peak fields.
- The average annual *natural*, or underlying, decline rate for the world as a whole – stripping out the effects of ongoing and periodic investment – is estimated at 9% for post-peak fields. In other words, the decline in production from existing fields would have been around one-third *faster* had there been no capital spending on those fields once they had passed their peak.
- Our Reference Scenario projections imply a one percentage-point increase in the global average natural decline rate to over 10% per year by 2030 as all regions experience a drop in average field size and most see a shift in production to offshore fields. This means that total upstream investment in some countries will need to rise, in some cases significantly, just to offset decline.

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Understanding production patterns and trends

An understanding of oilfield production profiles and the impact of various geological and economic variables on the shape of production curves is critically important to projecting future output from fields already in production or from fields that are yet to be brought into production. A major finding of past *Outlooks* is that the future rate of production decline from producing fields aggregated across all regions is the single most important determinant of the amount of new capacity that needs to be added and the need to invest in developing new fields (see, in particular, IEA, 2001 and 2003). In other words, future supply is far more sensitive to decline rates than to the rate of growth in oil demand.[1] Most investment over the projection period will actually be needed to offset the loss of capacity from existing fields as they mature, oilfield pressure declines and – in the absence of new investment – well flow-rates fall (see Chapter 13 for a detailed analysis of investment trends).

For these reasons, we have undertaken a detailed study of historical oilfield production trends, using extensive field-by-field data, with a view to achieving a better understanding of the drivers of decline rates, how they could develop in the future and what that will mean for investment. The results of this study were used to model future production levels to 2030, the results of which are set out in detail in Chapter 11.

The field-by-field study involved building a large database containing the full production history and a range of technical parameters for around 800 of the largest individual oilfields in the world. The database includes, to the best of our knowledge, all the super-giant fields, containing initial proven and probable (2P) reserves[2] exceeding 5 billion barrels; virtually all giant fields, containing more than 500 million barrels, in production today; and the bulk of the world's large fields, containing at least 100 million barrels. Together, these fields account for close to three-quarters of all the initial reserves of all the fields ever discovered worldwide and more than two-thirds of all the crude oil produced globally in 2007 (see Box 10.1 for more details). We believe that this is the most comprehensive study of field-by-field oil production patterns and trends ever made public.[3] We intend to extend and refine this work in the future.

The majority of the fields that have ever been found worldwide have already been brought into production. The share is highest for the biggest fields, both in terms of their number and their overall reserves, mainly because all but a handful of them were discovered several decades ago. Out of an estimated 58 super-giant fields that have been found, all but four[4] are already in production; out of close to 400 giant fields that we have identified, around 80 are either being developed, waiting to be developed

1. See Chapter 11 for the results of an analysis of the sensitivity of oil production and prices to changes in decline rates.

2. All reserves figures cited in this chapter are 2P unless otherwise stated.

3. IHS/CERA prepared a study on oilfield decline rates based on data for 811 fields for private clients in 2007 (CERA, 2007).

4. Azadegan and Ferdows/Mound/Zagheh in Iran, Kashagan in Kazakhstan, and Tupi in Brazil are not yet producing.

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or are temporarily shut in.[5] The combined initial 2P reserves of all super-giant and giant fields amount to 1 306 billion barrels, of which an estimated 697 billion barrels remain (equal to about half of the world's remaining reserves of conventional oil – see Chapter 9). In total, an estimated 79% of the world's remaining conventional oil reserves are contained in fields that are already being exploited. Thus, the outlook for production at these fields is critical to world oil supply in the short to medium term.

SPOTLIGHT

What do rising decline rates mean for oil production and investment?

The production profile of an oilfield reflects a number of different factors, including the techniques used to extract its reserves, the field-development programme, reservoir management practices, geology, national production policies, field-maintenance programmes and external factors, such as strikes and military geopolitical conflicts. The analysis presented below points to a long-term trend towards higher faster decline rates once oilfields have reached their peak, as a result of a shift in the pattern of fields that will be brought on stream in the future. In particular, a growing share of production is expected to come from smaller fields and, in the medium term, from fields located offshore, which tend to decline much more quickly than big, onshore fields because of the way they are developed. This is, in turn, largely a function of technical and economic factors rather than geology. Faster decline rates go hand-in-hand with higher peak-production levels relative to reserves.

Rising decline rates have important implications for development costs and investment needs. In general, the smaller a field, the more expensive it is to develop (and operate), expressed in dollars per barrel per day of capacity and, especially, per barrel of oil produced. Similarly, costs are typically significantly higher for offshore fields, particularly in deep water. Over the projection period, all regions continue to experience a drop in average field size and most see a shift in production to offshore fields as the biggest fields, which are usually found and developed first, decline. This means that total upstream investment in some countries will need to rise, in some cases significantly, just to offset decline (even though total world investment needs are expected to drop, as the share of the lowest-cost producing regions in total production increases). The biggest increases are needed in OPEC countries. It is far from certain that all the required investment will be forthcoming, given the size of these investments and potential barriers (see Chapter 13) – because of so-called "above-ground" factors and not because of geology. These factors are discussed in detail in the next four chapters.

5. These figures do not include some new fields, including offshore Brazil, as they are yet to be properly appraised.

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Current estimates of reserves are derived from the latest estimates of the oil initially in place and the share that can be economically recovered. Yet that share, as well as the rate at which that share can be produced, are far from certain, as the precise behaviour of a given field or reservoir is exceedingly difficult to predict. Moreover, the deployment of new production technologies (including secondary and enhanced recovery techniques) can push up ultimate recovery rates and production levels. Careful analysis of these factors is vital to predicting future recovery and decline rates and, therefore, production.

Box 10.1 • *The IEA field-by-field oil production database*

The IEA has compiled a database containing the full crude oil production history and a range of key technical parameters for a total of 798 oilfields worldwide. To the best of our knowledge, the database includes all of the world's 54 super-giant fields that have ever produced, as well as the bulk of the giant producing fields (263 out of a total of around 320).[6] Of the remaining 481 fields, 285 are large fields, representing at least half of all the fields in this category in the world and most of the largest ones. The rest of the fields are small fields, containing between 50 and 100 million barrels. The choice of which large and small fields to include in the database was partly driven by data availability. Nonetheless, we believe that the dataset for large fields is reasonably representative of the actual geographic distribution of all such fields in production worldwide today.

For all producing fields, data was compiled on annual oil production over the full life of the field, initial and remaining proven and probable (2P) recoverable reserves, the volume of oil initially in place, lithology (the geological formation of the field), physiographic location (onshore, offshore and shallow/deep water) and the discovery date. For some fields, additional information on reservoir porosity and thickness, as well as the deployment of improved recovery techniques, was also obtained.

The field-by-field data were compiled from a range of different sources. The primary source of data on production and reserves was IHS, without whose assistance we would not have been able to carry out this work. Deloitte & Touche Petroleum Services also provided data on a number of fields. The US Geological Survey and the US Energy Information Administration supplied data for some US fields. Other sources include official statistics, published by the governments of oil-producing countries, international and national oil companies, oil services companies and consulting firms. These organisations assisted us in validating and checking the consistency and veracity of the data, as well as in verifying the results of our analysis. We gratefully acknowledge their contribution.

6. The precise number of fields in these categories may differ among data sources, because of differences in the way specific fields are delineated and data discrepancies.

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The importance of size

There are currently about 70 000 oilfields in production worldwide. The bulk of crude oil production comes from a small number of very prolific fields, mostly super-giants and giants.[7] Output at the world's ten largest producing oilfields totalled just over 14 million barrels per day (mb/d) in 2007 (Table 10.1), contributing 20% of world conventional production. The 20 largest fields produced 19.2 mb/d, or over a quarter of world production. One field alone – Ghawar in Saudi Arabia – produced 5.1 mb/d, equal to 7% of world conventional oil production (see the next section).

Table 10.1 • The world's 20 biggest oilfields by production

Field	Country	Location	Year of discovery	Peak annual production		2007 production
				Year	kb/d	kb/d
Ghawar	Saudi Arabia	Onshore	1948	1980	5 588	5 100
Cantarell	Mexico	Offshore	1977	2003	2 054	1 675
Safaniyah	Saudi Arabia	On/off	1951	1998	2 128	1 408
Rumaila N & S	Iraq	Onshore	1953	1979	1 493	1 250
Greater Burgan	Kuwait	Onshore	1938	1972	2 415	1 170
Samotlor	Russia	Onshore	1960	1980	3 435	903
Ahwaz	Iran	Onshore	1958	1977	1 082	770
Zakum	Abu Dhabi (UAE)	Offshore	1964	1998	795	674
Azeri-Chirag-Guneshli	Azerbaijan	Offshore	1985	2007	658	658
Priobskoye	Russia	Onshore	1982	2007	652	652
Top 10 total						**14 260**
Bu Hasa	Abu Dhabi (UAE)	Onshore	1962	1973	794	550
Marun	Iran	Onshore	1964	1976	1 345	510
Raudhatain	Kuwait	Onshore	1955	2007	501	501
Gachsaran	Iran	Onshore	1928	1974	921	500
Qatif	Saudi Arabia	On/Off	1945	2006	500	500
Shaybah	Saudi Arabia	Onshore	1968	2003	520	500
Saertu (Daqing)	China	Onshore	1960	1993	633	470
Samotlor (Main)	Russia	Onshore	1961	1980	3 027	464
Fedorovo-Surguts	Russia	Onshore	1962	1983	1 022	458
Zuluf	Saudi Arabia	Offshore	1965	1981	677	450
Top 20 total						**19 163**

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

7. In this report, a super-giant is defined as a field with initial 2P reserves of at least 5 billion barrels. A giant is defined as a field with initial reserves of 500 million barrels to 5 billion barrels. A large field contains more than 100 million barrels.

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Four of the other fields are also in Saudi Arabia and eight others in other Middle Eastern countries (Iran, Iraq, Kuwait and the United Arab Emirates). Output in 2007 at 16 of the 20 largest fields was below their historic peaks. Production has fallen most in percentage terms at Samotlor in Russia. All of the 20 largest producing fields are super-giants, of which Ghawar, with 140 billion barrels of initial reserves, is by far the largest.

Most of the world's largest fields – by production and reserves – have been in production for many years, in some cases for several decades. The last of the top 20 producing fields to be discovered was Azeri-Chirag-Guneshli in 1985. Priobskoye in Russia was found in 1982, Canterell in Mexico in 1977, and all the others between 1928 and 1968. In 2007, five fields produced more than 1 mb/d and another eight more than 500 thousand barrels per day (kb/d). They make up one-quarter of world crude oil production. Around 110 fields in total produce more than 100 kb/d each. Collectively, they account for just over 50% of world production. A very large number of small fields, each producing less than 100 kb/d at present – approximately 70 000 in total – produce just under half of world production.

Table 10.2 • World crude oil production by output and age of field

	Number of fields	Year of first production					Production, 2007	
		Pre-1970s	1970s	1980s	1990s	2000s	mb/d	%
> 1 mb/d	5	4	1	-	-	-	10.6	15
500 kb/d – 1 mb/d	11	8	-	1	2	-	6.7	10
All fields	**70 000**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**70.2**	**100**

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

The world's oil supplies remain very dependent on output from big, old fields. Despite the fact that many of them have been in production for decades, output from super-giant and giant fields (holding more than 500 million barrels of initial reserves) has actually grown significantly over the past two decades. The share in world production of all the super-giant fields and those giant fields included in our database rose from 56% in 1985 to 60% in 2007. Surprisingly, fields that came into production before the 1970s still make the largest contribution, amounting to just over 24 mb/d in 2007 – equal to 35% of the world total (Figure 10.1). Indeed, output from these fields has gradually risen since the mid-1980s (it fell sharply in the early 1980s, mainly because of OPEC policies). Only five super-giant or giant fields began producing in the current decade – Ourhoud in Algeria, Grane in Norway, Girassol in Angola, Jubarte in Brazil and Xifeng in the Gansu province of China – and made up a mere 2% of total output from such fields and little more than 1% of world output in 2007.

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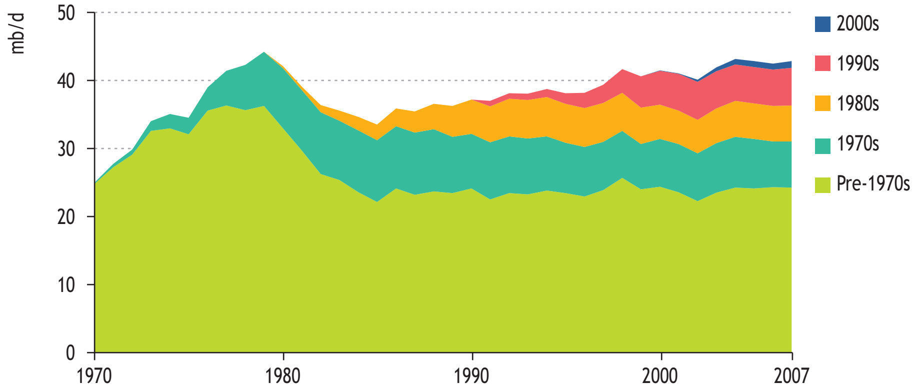
Figure 10.1 ● *World crude oil production from super-giant and giant fields by field vintage*



Note: For fields covered by IEA field-by-field oil production database (which includes all the world's super-giant fields and most giant fields). Fields are classified according to the year of first production.

Sources: IHS and Deloitte & Touche databases; other industry sources; IEA estimates and analysis.

Regional differences

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Big oilfields are unevenly distributed across the world; their share in overall production and their average size vary markedly across regions. The Middle East is characterised by a large number of super-giant and giant fields. With 9 billion barrels of initial reserves, their average size is the highest of any region (Table 10.3).

Table 10.3 ● *Geographical distribution of the world's super-giant and giant oilfields* (number)

	Super-giants and giants	Of which offshore	Average size of total (billion barrels)
OECD North America	46	11	2.0
OECD Europe	23	23	1.4
OECD Pacific	2	2	1.1
E. Europe/Eurasia	62	5	3.1
Asia	20	5	2.1
Middle East	83	25	8.9
Africa	41	12	1.7
Latin America	40	6	3.4
Total	**317**	**89**	**4.2**

Note: For fields covered by IEA field-by-field oil production database. See footnote 7 for definitions of super-giant and giant fields.

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

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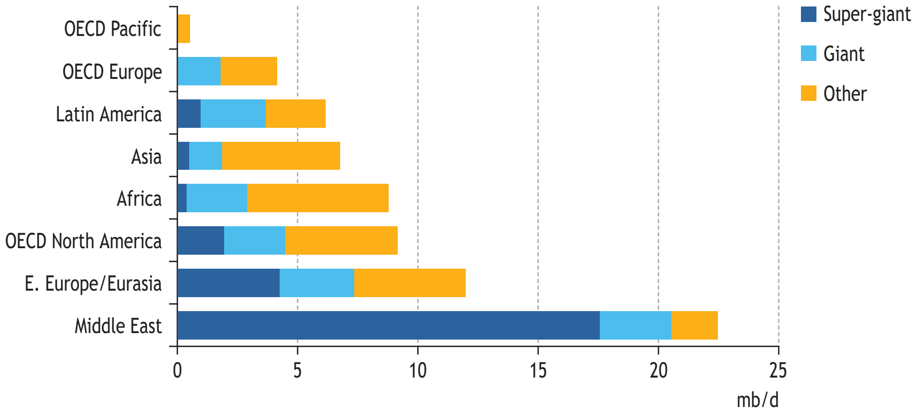
The region holds a quarter of all super-giant and giant fields. Around three-quarters of the world's super-giant and giant fields are located onshore (including fields that straddle land and sea). The share is highest in the Middle East, Asia and the former Soviet Union. In Europe, all big fields are located offshore. Super-giant and giant fields account for the largest share of production in the Middle East, Russia and the Caspian region (Eastern Europe/Eurasia) and Latin America (Figure 10.2). Their share is lowest in Asia, Europe and the Pacific region. Although North America accounts for just over a quarter of all the crude oil ever produced in the world and 13% of current output, there are little more than 50 super-giant and giant fields in that region – a far smaller number relative to output than in any other region.[8]

Figure 10.2 • Crude oil production by region and size of field, 2007



Note: For fields covered by IEA field-by-field oil production database. See footnote 3 for definitions of super-giant and giant fields.
Sources: IHS and Deloitte & Touche databases; other industry sources; IEA estimates and analysis.

There are also big differences, according to their geographic location and their size, in the extent to which reserves have been depleted. Among all fields in production today, the depletion factor – the share of initial reserves that has already been produced – is marginally higher for the super-giant and giant fields. Worldwide, those fields are on average 48% depleted (weighted by total production), compared with 47% for other fields included in our study (Table 10.4). Depletion factors are highest for North America, where most fields have been in production for decades, and Europe, where small fields dominate production. They are lowest in the Middle East.

8. The highly fragmented ownership of North American fields means that many large formations are broken down statistically into separate fields, resulting in a smaller number of giants.

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Table 10.4 • Average depletion factor of producing fields* by size, 2007

	Super-giants and giants	Others	All fields
OECD North America	78%	83%	81%
OECD Europe	77%	71%	73%
Middle East	37%	14%	32%
Africa	61%	44%	50%
Total	**48%**	**47%**	**48%**

* Based on the full IEA dataset of 798 fields.
Note: The depletion factor is cumulative production divided by initial 2P reserves.
Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

Oilfield production profiles and characteristics

Every oilfield follows a unique production profile, according to the natural characteristics of the reservoirs within it, the manner in which it is developed and production-management policies. Typically, an oilfield goes through a build-up phase, during which production rises as newly drilled wells are brought into production, a period of plateau production, during which output typically is broadly flat as new wells are brought on stream offsetting declines at the oldest producing wells, and a decline phase, during which production gradually falls with reservoir pressure.

In practice, oilfields rarely follow a smooth, predictable production path. Commercial and policy considerations affect how a field is developed. And reservoirs behave in different ways at different stages of depletion for geological and technical reasons. In addition, production rates can fluctuate sharply as new phases of a field's development are launched, often to combat the "natural" or underlying decline in output. In general, with larger fields, the build-up period is long and development is pursued in phases. Some fields can build up over several decades: the Zakum field in the United Arab Emirates, for example, began producing in 1967 and hit record output of 790 kb/d only in 2002 – a level that is expected to be exceeded in the future. Periodic maintenance programmes (scheduled and unplanned) and deliberate shut-ins for policy reasons (for example, to comply with national production quotas) can also upset the underlying trend in production.

Standard production profiles

Distinguishing the impact of the inherent technical characteristics of specific types of fields from the effect of how those fields are developed and managed over time is crucial to understanding historic production trends and assessing the long-term prospects for output – both for fields that are already producing and those that are yet to be developed. For this reason, we have identified standard production profiles for different types of oilfields and assessed how those profiles differ according to a number of technical variables. This analysis is based on a sample of 725 fields from our oilfield database, with an average production history of just under 22 years and total initial reserves of 1 358 billion barrels (Table 10.5) The oldest field, Balahani-Sabunchi-

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Ramani in Azerbaijan, started producing in 1871. The full dataset could not be used, because of a lack of data on certain technical parameters. Nonetheless, almost all super-giant and giant fields are included, together with most large fields.

Table 10.5 • Initial reserves of oilfield dataset for production profiling

	Number of fields	**2P reserves** (billion barrels)
By location		
Onshore*	400	1 120
Offshore shelf	294	213
Offshore deepwater	31	25
By lithology		
Carbonate	145	716
Sandstone	473	613
Chalk	12	6
Unknown	95	23
Total	**725**	**1 358**

* Includes fields partially offshore.

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

The analysis revealed that the size of reserves and the physiographic situation (onshore/offshore) are the most important variables in explaining the shape of the production profiles (Box 10.2). Lithology – essentially whether the field is carbonate or sandstone – does not appear to influence to a significant degree the shape of the production profile, everything else being equal. The results show that small fields reach their peak sooner, produce a higher share of initial reserves by peak and decline more rapidly than large fields (Table 10.6 and Figure 10.3). It takes about twice as long for big fields to get to peak. Everything else being equal, peak production relative to reserves at offshore (shelf) fields is higher than at onshore fields, reflecting the need for developers to recover more quickly the higher costs usually associated with offshore fields. Deepwater fields, although usually big, behave in a similar way to small offshore fields with peak production reached after five years. On average, 7% of reserves are produced in that year, with cumulative production reaching 22% of reserves. The production curve for deepwater fields is, thus, highly skewed to the left, with less than a quarter of reserves produced in the relatively brief pre-peak period. Generally, offshore fields tend to have fewer wells but more highly productive horizontal wells. Spacing between wells is also much wider for offshore fields, because of the higher cost of drilling wells.

The notional average productive life of each category of field (on the assumption that cumulative production equals total initial reserves when the field is abandoned) differs markedly, from 27 years for deepwater fields to 110 years for fields holding more than 1.5 billion barrels. In practice, however, the tail of production at mature fields is strongly influenced by the prevailing economic conditions. The water cut (the share of water contained in the mixture of hydrocarbons and water that flows from the well) tends to rise towards the end of a field's life, pushing up processing costs. For as long as total operating costs are below the market value of the oil recovered, production can be sustained at relatively low levels for a long time. Since the behaviour of heavily depleted fields varies, the estimates presented here should be considered indicative only.

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Box 10.2 ● *Oilfield production-profiling methodology*

The analysis of oilfield production profiles seeks to explain the shape of standardised profiles according to a number of technical variables, namely:

- Total crude oil reserves.
- Physiographic situation (onshore, shallow offshore and deep water).
- Lithology (carbonate, sandstone and chalk).
- Permeability, thickness and porosity of the reservoir and the API gravity of the liquids present (for fields holding initial reserves of at least 1 billion barrels). These parameters were amalgamated into a single indicator of the transmissibility of the fluid in the reservoir rock, by multiplying permeability and thickness with each other and dividing the result by gravity.

The analysis revealed that the size of reserves and the physiographic situation were the most important variables in determining the shape of the production profile. Therefore, normalised production curves (plotting annual production against cumulative production, both expressed as the share of initial 2P reserves) were first estimated according to the size of reserves for three categories: over 1.5 billion barrels; between 500 million and 1.5 billion barrels; and less than 500 million barrels. Using statistical techniques, the degree of influence of the other technical variables in explaining the shape of the normalised production curves was then estimated.[9] The results were used to produce mean normalised curves for each size category of field according to different variants of the technical variables. The mean curves were then extended to show how each category of field would be expected to behave through to full depletion of reserves. This was done by assuming an exponential rate of change.

10

Table 10.6 ● Production characteristics of sample oilfield dataset for production profiling

	% of initial reserves produced in the peak year	Cumulative % of initial reserves produced in the peak year	Number of years of production at plateau*	Estimated average total number of production years**
Onshore, < 500 Mb	3.9	21	7	75
Shelf, <500 Mb	9.7	25	4	60
Onshore, 500 Mb – 1.5 Gb	2.3	17	10	90
Shelf, 500 Mb – 1.5 Gb	3.5	20	8	65
All, > 1.5 Gb	1.7	15	13	110
Deepwater	7.0	22	5	27

* Defined as the period during which production is more than 85% of that in the peak year.
** Over the full life of the field, assuming that cumulative production strictly equals initial reserves.
Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

9. A detailed explanation of the procedures used can be found at www.worldenergyoutlook.org.

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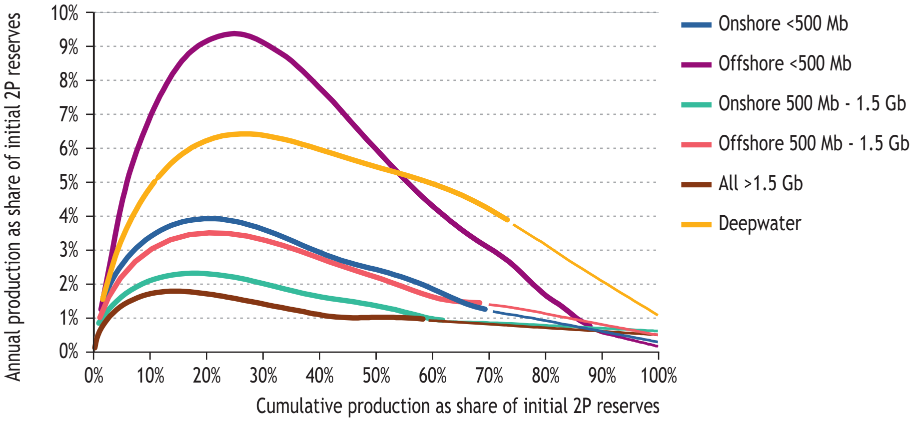
Figure 10.3 • ***Standard oilfield-production profiles by category of field***



Note: The thick lines are derived from observed data; the thin lines show the trajectory assuming full depletion of the field.

Focus on giant fields

We extended further the analysis of the oil-production profiles of super-giant fields and those giants in our sample holding initial reserves of more than 1 billion barrels. For these fields, we collected additional data on porosity, permeability and thickness of reservoirs, as well as the gravity of the oil, to test the influence of these factors on the shape of the standard production profiles. The results show that the size of the field is still the dominant variable, with transmissibility (permeability and viscosity) playing a less important role. Porosity and lithology do not seem to have any influence.

We identified distinct differences in the standard profiles for fields holding between 1 and 2.8 billion barrels and those holding more than 2.8 billion barrels. For the first set of fields, transmissibility is a more important determinant of the shape of the production profile than the physiographic situation of the field. Those fields with high transmissibility tend to reach a higher plateau sooner and to be produced more rapidly: 68% of reserves are produced after about 30 years, while the corresponding figure for low transmissibility fields is only 57% (Figure 10.4).

The impact of all technical variables other than the size of reserves on the production profile of fields holding more than 2.8 billion barrels was not found to be statistically significant. This may be explained by the influence of non-technical factors, such as production quotas and geopolitical factors, especially in the Middle East, where many of the largest fields are found. In addition, the development of large fields tends to occur in phases, according to long-term technical, economic and political objectives. As a result, they are less likely to conform to standard profiles.

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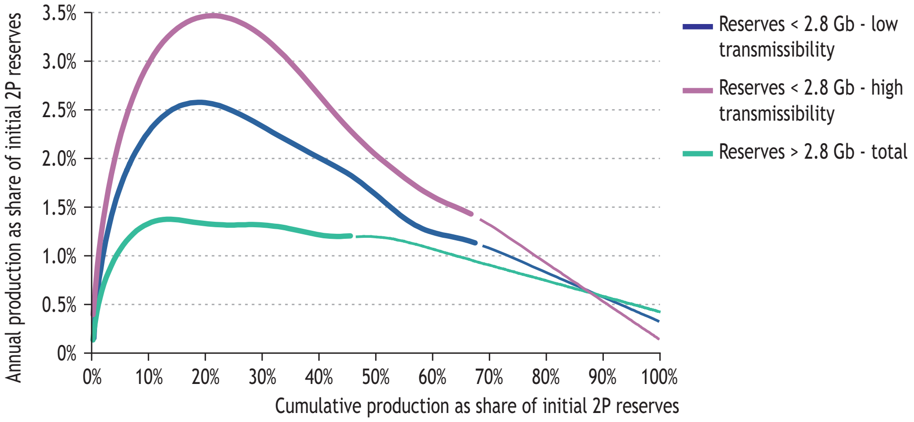
Figure 10.4 • *Standard oilfield-production profiles of giant fields*



Note: the thick lines are derived from observed data while the thin lines show the trajectory assuming full depletion of the field.

Changes in production profiles over time

The standard production profiles for the six categories of field analysed above (Figure 10.3) are derived from production data for fields that came into production at different times over several decades. Three-quarters of the fields with reserves of more than 1.5 billion barrels in this dataset started to produce in the 1970s or earlier. More than 60% of medium-sized fields, both onshore and offshore, also started producing in the same period. The smallest fields were generally developed later: half of small onshore fields and more than three-quarters of small offshore fields started to produce in the last 15 years.

Analysis of production profiles by vintage shows that fields developed in recent years tend to build up more quickly to a higher plateau (relative to reserves), maintained over a shorter period of time, than fields developed before the 1990s. For example, Hassi Berkine Sud, a medium-sized Algerian field brought into production in 1998, recently reached plateau production equal to around 6% of reserves compared with a typical peak of little more than 2% for all onshore fields of similar size in our dataset (Figure 10.5). This finding is not particularly surprising: advances in production technology have made it financially attractive to introduce improved and enhanced recovery techniques earlier in a field's life. In addition, the pressure from investors on private companies to minimise the payback period and so maximise the net present value of future cash-flow, has increased in recent years.

Measuring observed production decline rates

Approach and definitions

While each phase of an oilfield's life is important, the rate at which production from oilfields declines once it has reached peak production is critical to determining the

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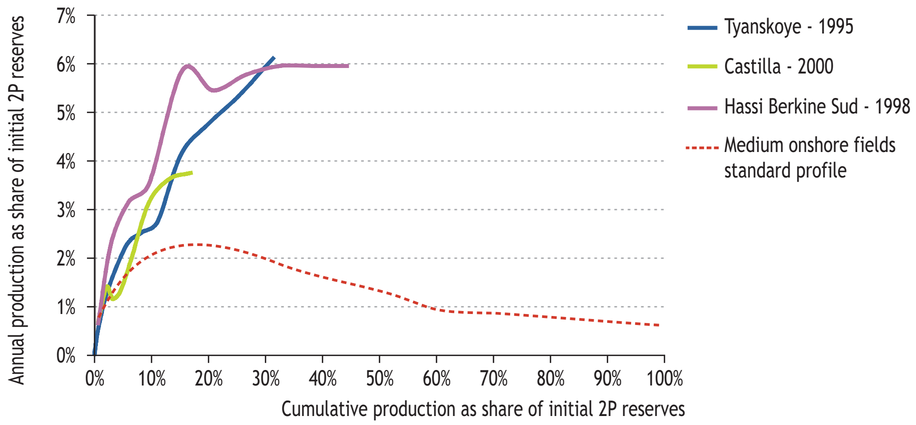
need for additional capacity, either through further development work at existing fields or by bringing new fields into production. At a global level, the faster the rate of decline, the greater the need for additional capacity for a given level of demand. The actual rate of decline, how it has changed and how it could evolve in the years to come have assumed enormous importance in the current debate about the medium- and long-term prospects for oil supply. For this reason, we have carried out an in-depth, field-by-field analysis of decline rates in order to improve understanding about the topic and gain insights into future production trends.

Figure 10.5 • *Selected production profiles of recently developed medium-sized onshore fields compared with the standardised profile*



Discussions about decline rates are often confused by a failure to make clear what is meant by the term and exactly how they are calculated. It is important to understand that, at any given moment, some oilfields will be ramping up to peak production, others will be at peak or plateau, and others will be in decline. Averaging rates across a group of fields does not, therefore, reveal by itself any clear information on the decline rate of fields at different stages of their production life. Only a field-by-field analysis of production trends can shed light on this. In this section, we use our field-by-field database to quantify decline rates in detail and analyse long-term trends. The subsequent section looks at how decline rates could evolve over the projection period. The precise definitions and methods used to measure decline rates are described in Box 10.3.

Of a total of 798 producing fields in our field-by-field database, we prepared a dataset of 651 fields with initial reserves of at least 50 million barrels in order to carry out our analysis of decline rates. Of this set, 580 fields were found to have passed peak production (Table 10.7). In other words, for each of these fields, production over the latest year of production is below the maximum level ever achieved in any one year. These fields produced a total of 40.5 mb/d in 2007, or 58% of world crude oil production. Their initial reserves total 1 241 billion barrels, equal to 52% of the world total. Of the post-peak fields, a total of 479 were found to be in the post-plateau phase. Of these, 362 fields are in decline phase 3 (with annual production at less than

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Box 10.3 • *How do we define and calculate decline rates?*

Peak production is the highest level of production recorded over a single year at a given field.

An oil field is in **decline** when aggregate production in the latest year (2007 for most fields in the dataset used for this analysis) is below production in the peak year, even if the field attains other lower peaks in the interim. **Plateau production** is when annual production is more than 85% of peak production. A field is in the **post-plateau phase** when it has fallen below plateau. For the purposes of our decline rates calculations, only fields with production in the last year of production that is below the level of the first year of post-plateau production are included.

The full period of production decline after peak is broken down into three distinct phases for the purposes of measurement: **decline phase 1** is the period from peak annual production to the last year of plateau production; **decline phase 2** is from the first year at which production falls below plateau through to the last year in which production is above 50% of peak; and **decline phase 3** is the period after which production is consistently below 50% of peak.

The **observed decline rate** is the cumulative average annual rate of change in observed production between two given years (for example, between peak production and the latest year).

The **natural decline rate**, sometimes called the underlying decline rate, is the notional rate of decline in production between two given years had there been no investment beyond that associated with the initial development of the field. The methodology used to estimate this rate by region is described in Figure 10.9 below.

Unless otherwise mentioned, all the decline rates referred to in this chapter are **production-weighted**. In other words, the average for a particular group of fields (by type or region) takes into account the level of production of each field in the total. Cumulative production over the full life of the field was used to weight decline rates for fields currently in production and in the post-peak phase.

Generally, historical observed decline rates were calculated using the full production history of each field. Of course, these vary greatly in length: the oldest field in our dataset has been producing for 137 years and the youngest for two years (the minimum period for which calculating a decline rate is possible). Solely for the purposes of measuring long-term trends, decline rates were also calculated on a year-by-year basis, with the decline rates for each field weighted by the actual production in the given year.

half that at peak). A larger share of super-giant fields are in the post-plateau phase, as most of them have been in production for several decades. Nonetheless, the world's biggest field by far – Ghawar – is not among the post-plateau fields, as production in 2007 was still less than 15% below the peak of 5.6 mb/d reached in 1980 (Box 10.4).

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Table 10.7 • Number of oilfields in dataset for decline rate calculations

	Super-giant	Giant	Other	All fields
By location				
Onshore*	43	185	159	387
Offshore shelf	11	61	147	219
Offshore deepwater	0	17	28	45
By lithology				
Carbonate	32	69	59	160
Sandstone	22	189	268	479
Chalk	0	5	7	12
By grouping				
OPEC	40	97	48	185
Middle East	*33*	*41*	*8*	*82*
Other	*7*	*56*	*40*	*103*
Non-OPEC	14	166	286	466
By region				
OECD	3	68	150	221
North America	*3*	*43*	*56*	*102*
Europe	*0*	*23*	*89*	*112*
Pacific	*0*	*2*	*5*	*7*
Non-OECD	51	195	184	430
E. Europe/Eurasia	*10*	*52*	*14*	*76*
Asia	*1*	*19*	*73*	*93*
Middle East	*33*	*50*	*18*	*101*
Africa	*1*	*40*	*53*	*94*
Latin America	*6*	*34*	*26*	*66*
Total	**54**	**263**	**334**	**651**

* Includes fields partially offshore. The dataset includes all post-peak fields in our database.

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

Results of the analysis

The observed post-peak decline rate averaged across all fields on a production-weighted basis is 5.1% using raw data. That is equal to 3.6 mb/d per year, based on the 2007 level of global crude oil production. As the standard production profiles suggest, decline rates are lowest for the biggest fields: they average 3.4% for super-giant fields, 6.5% for giant fields and 10.4% for large fields (Table 10.8). Rates are also lowest for onshore fields and highest for deepwater offshore fields, reflecting the different ways in which they are developed (as described in the previous section). On average worldwide, production has declined yearly by 4.3% at onshore fields and 7.3% at offshore fields, with deepwater fields declining by 13.3%. Sandstone fields have declined significantly faster than carbonate fields, 6.3% versus 3.4%, but this largely reflects the fact that the latter tend to be much larger and are more often located in the Middle East (where decline rates have been tempered by historically conservative production policies);

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Box 10.4 • *The Ghawar field: the super-giant among super-giants*

The Ghawar field – the world's largest – was discovered in 1948 and started producing in 1951. The area of the field – more accurately described as a collection of oil-bearing formations – is partitioned into six geographical areas, from north to south: Ain Dar, Shedgum, Farzan, Hawiyah, Uthmaniyah and Haradh. Oil is produced from the Jurassic formations, namely Arab, Dhruma and Hanifa, while gas and condensate are extracted from the deeper and older reservoirs, in the Khuff, Unayzah and Jawf formations. Ghawar crude, which has an average gravity of around 34° API and sulphur content of 1.8%, accounts for most of the Saudi Arab Light export blend.

Ghawar is a large anticline structure, 280 km long by 25 km wide, with about 50 metres of net oil pay. Initial oil in place is 250 billion barrels, of which initial recoverable reserves are estimated at 140 billion barrels (implying an expected ultimate recovery rate of 56%). Cumulative production reached 66 billion barrels in 2007, so remaining reserves are about 74 billion barrels. Ghawar produced 5.1 mb/d of crude oil in 2007, down from a peak of 5.6 mb/d in 1980 (when the field's capacity was fully utilised in response to the loss of Iranian production following the revolution) and a recent peak of 5.3 mb/d in 1997. The observed post-peak decline rate is, thus, a mere 0.3% per year. Ghawar is still at the plateau phase of production on our definition (Box 10.3).

Reservoir pressure is maintained through the use of peripheral water flooding, whereby seawater is injected into the reservoir in the oil layer just above the tar mat that separates the oil layer from the aquifer. The water pushes the oil inwards and upwards, towards the producing wells. This secondary recovery technique, first used at Ghawar in 1965, typically results in lower flow rates than the more commonly used pattern water flooding, but tends to result in a higher recovery rate and allows for plateau production to be maintained for longer (see IEA, 2005 for more details). Nonetheless, as the field has matured, maintaining reservoir pressure and sustaining production has become more difficult and costs have risen. The water cut – the share of water in the liquids extracted – increased sharply in the 1990s, reaching 37% in 2000. However, recent development work has succeeded in reducing the water cut to 27% at present, according to Saudi Aramco, the field operator.

Ghawar has been developed in distinct stages, which have progressively raised the field's capacity and kept the field at plateau. The most recent project, involving the Haradh area in the southern part of the field, was completed in 2006, tripling capacity there to about 900 kb/d. This has helped to offset natural declines in other parts of the field. The overall capacity of Ghawar is sustained by infill drilling and well work-overs to maintain flow pressure in various parts of the field. Reports suggest that enhanced oil recovery techniques are being used to boost capacity in the mature zones of the Shedgum and Uthmaniyah areas, where extensive drilling programmes have recently been undertaken (Sanford Bernstein, 2007).

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lithology does not appear to be a major determinant of decline rates (see the previous section). Regardless of location or lithology, decline rates are, in most cases, lower the bigger the field. Similarly, the rates of post-plateau decline are usually slightly higher than the rate of post-peak decline, confirming the results of the production-profiling analysis (Figure 10.6).[10] Worldwide, the average rate of observed post-plateau decline is 5.8% for the 479 fields that are in the post-plateau decline phase out of the 580 post-peak fields and the total of 798 fields in our database.[11]

Table 10.8 • *Production-weighted average observed decline rates by size and type of field*

	Post-peak				Post-plateau			
	Super-giant	Giant	Large	Total	Super-giant	Giant	Large	Total
Onshore	3.4%	5.6%	8.8%	4.3%	4.9%	5.5%	9.4%	5.3%
Offshore	3.4%	8.6%	11.6%	7.3%	1.2%	9.0%	11.7%	7.2%
Shelf	*3.4%*	*7.7%*	*11.2%*	*6.6%*	*1.2%*	*8.6%*	*12.2%*	*6.7%*
Deepwater	-	*13.1%*	*14.2%*	*13.3%*	-	*10.8%*	*12.6%*	*11.2%*
Carbonate	2.3%	6.6%	8.9%	3.4%	2.7%	6.9%	9.3%	4.3%
Sandstone	4.8%	6.5%	10.9%	6.3%	5.5%	6.5%	11.1%	6.6%
World	**3.4%**	**6.5%**	**10.4%**	**5.1%**	**4.3%**	**6.6%**	**10.7%**	**5.8%**

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

Decline rates also vary markedly by region. Rates are lowest in the Middle East and highest in the North Sea (Table 10.9). This reflects, to a large extent, differences in the average size of fields, which in turn is related to the extent to which reserves are depleted and their location onshore or offshore. North Sea fields tend to be much smaller than Middle East fields, while almost all significant North Sea fields are located offshore. North Sea fields (which make up all the European fields in our dataset) have declined on average by 11.5% per year since peak and 13.3% since plateau. The relatively low decline rates of Middle East fields, which have averaged less than 3% per year, is also explained by the

10. The average post-peak decline rates calculated using the standard production profiles for different categories of field by size are, unsurprisingly, of a similar magnitude to the rates calculated using raw data that are presented in this section.

11. The observed decline rates shown in this chapter differ from those for non-OPEC countries described in the IEA's most recent *Medium-Term Oil Market Report*, published in July (IEA, 2008). This is because of methodological differences, associated with the different time horizons of the two reports. The *MTOMR* estimates decline rates on a year-by-year basis, rather than over the full production life of the field. The *MTOMR* also adjusts raw field-by-field production data for temporary reductions in output caused by unexpected events such as weather-related outages, strikes and security-related disruptions. Nonetheless, the results are similar.

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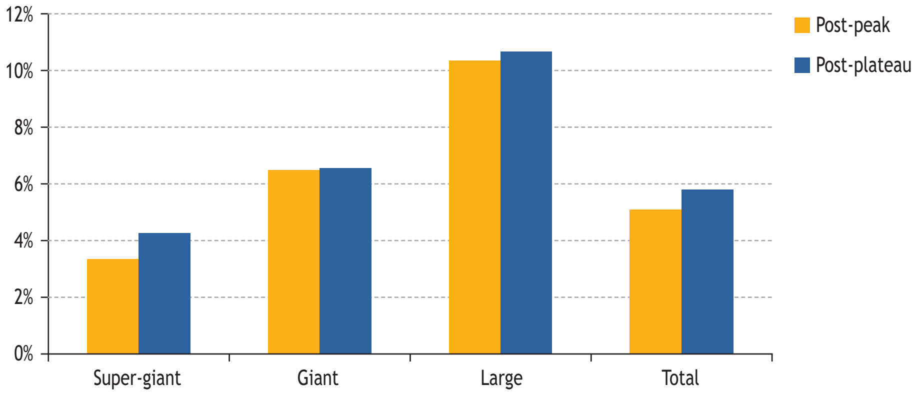
disruptions to the standard production profile caused by short-term production-management policies (notably in support of OPEC targets) and geopolitical conflicts. The dominance of Middle East countries and the heavy weight of super-giant fields in the population of OPEC fields contribute to the much lower average post-peak decline rates for OPEC compared with non-OPEC countries.

Figure 10.6 • **Production-weighted average post-peak and post-plateau observed decline rates by field size**



Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

10

Table 10.9 • **Production-weighted average annual observed decline rates by region**

	Post-peak				Post-plateau			
	Super-giant	Giant	Large	Total	Super-giant	Giant	Large	Total
OPEC	2.3%	5.4%	9.1%	3.1%	2.9%	4.8%	8.3%	3.6%
Middle East	*2.2%*	*6.3%*	*4.4%*	*2.6%*	*2.8%*	*6.5%*	*6.4%*	*3.4%*
Other	*4.8%*	*5.0%*	*10.2%*	*5.2%*	*3.8%*	*4.1%*	*8.8%*	*4.3%*
Non-OPEC	5.7%	6.9%	10.5%	7.1%	6.0%	7.4%	10.9%	7.4%
OECD North America	6.4%	5.4%	12.1%	6.5%	4.5%	6.0%	12.3%	6.0%
OECD Europe	-	10.0%	13.5%	11.5%	-	13.1%	15.5%	13.3%
OECD Pacific	-	11.1%	13.2%	11.6%	-	10.4%	12.6%	11.1%
E. Europe/Eurasia	5.1%	5.0%	12.1%	5.1%	5.3%	5.1%	12.4%	5.3%
Asia	2.1%	8.3%	6.6%	6.1%	2.5%	5.7%	6.7%	5.2%
Middle East	2.2%	6.5%	7.4%	2.7%	2.8%	7.0%	9.8%	3.7%
Africa	1.5%	5.2%	8.8%	5.1%	1.2%	5.2%	9.3%	5.0%
Latin America	8.4%	5.2%	6.9%	6.0%	9.5%	5.3%	6.8%	6.1%
World	**3.4%**	**6.5%**	**10.4%**	**5.1%**	**4.3%**	**6.6%**	**10.7%**	**5.8%**

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

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The impact of field age and maturity

In general, observed decline rates are higher the younger the field. For example, the average decline rate for all the non-OPEC fields in our dataset that have come on stream since the start of the current decade is 14.5%, compared with 11.6% for post-peak fields that started producing in the 1990s and only 5.9% for fields that started producing no later than 1969 (Table 10.10). This pattern applies to both OPEC and non-OPEC fields (Figure 10.7). The very low average decline rate for the pre-1970s vintage of OPEC fields – less than 3% – is influenced strongly by the very low observed post-peak decline rate of the Ghawar field (0.3%). The fall in the decline rate for OPEC fields that came into production since 2000 is explained by the fact that most of them, while past their initial peak, are still at plateau.

Table 10.10 • Production-weighted average post-peak observed decline rates by vintage*

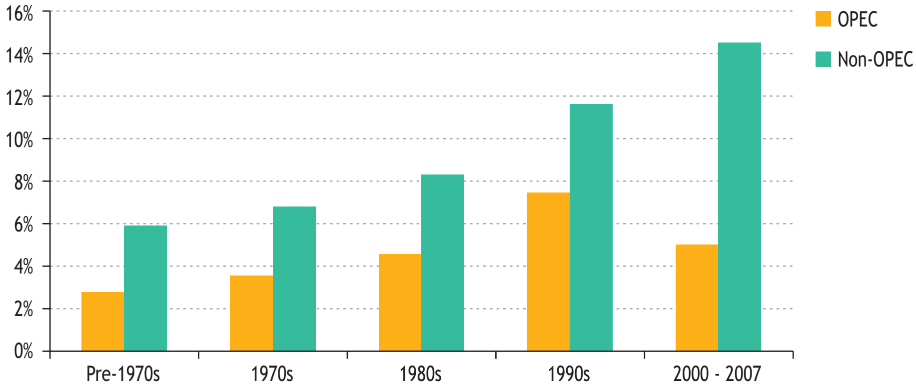
	Pre-1970s	1970s	1980s	1990s	2000s	Total
OPEC	2.8%	3.5%	4.6%	7.5%	5.0%	3.1%
Non-OPEC	5.9%	6.8%	8.3%	11.6%	14.5%	7.1%
World	**3.9%**	**5.9%**	**7.9%**	**10.6%**	**12.6%**	**5.1%**

* First year of production.

Source: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

As explained in the previous section, advances in production technology and changes in commercial practice mean that fields developed today tend to build up more quickly to a higher plateau, maintained over a shorter period of time, than fields developed before the 1990s. The growing importance since the 1970s of offshore fields (which normally reach a higher peak as a share of reserves than onshore fields) also explains this trend. It follows that the post-peak decline rate from such shorter and accelerated production profiles is higher.

Figure 10.7 • Production-weighted average post-peak observed decline rates by type of producer and year of first production



Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

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Decline rates show some variation according to the decline period (Box 10.3 for definitions), though the differences are less marked than for other factors including field size. For all post-peak fields still in decline phase 1 (*i.e.* whose production in the most recent year is still more than 85% of peak), the average decline rate is 1.4% (Table 10.11). The decline rate rises to 3.6% for those fields in decline phase 2 and to 6.7% in decline phase 3. For all three decline periods, rates are always lowest for the super-giant fields, with those still in decline phase 1 registering an average decline rate of only 0.8%. Once again, the large weight of the Ghawar field in this group of fields helps to lower the overall decline rate. The rise in the observed decline rate as a field reaches the end of its life is probably explained by the increase in the rate of decline in pressure.

Table 10.11 • *Production-weighted average annual observed decline rates by decline phase*

	Decline phase 1 (peak to end of plateau)	Decline phase 2 (plateau to 50% of peak)	Decline phase 3 (50% of peak to latest year)	Total
Super-giant	0.8%	3.0%	4.9%	3.4%
Giant	3.0%	3.7%	7.6%	6.5%
Large	5.5%	7.2%	11.8%	10.4%
World	**1.4%**	**3.6%**	**6.7%**	**5.1%**

Note: See Box 10.3 for precise definitions of the decline periods. Fields were sorted according to the period in which they currently lie (based on the last year of production data). Of the 580 post-peak fields included in our analysis, 101 were in decline phase 1, 117 in phase 2 and 362 in phase 3.

Source: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

Trends in observed decline rates

For individual fields, observed decline rates would be expected to change over time, because of changes in well productivity, as pressure drops, and in production policy, and because of investment in field re-development. At any given moment, fields will be at different stages of their production life, so the rate of observed decline averaged over all fields in decline inevitably changes over time. We have calculated the *year-on-year* change in production, averaged across all the post-peak fields in our dataset (all the decline rates shown up to this point correspond to the average over the life of each field). For each year, only those fields that were in decline were included in the calculation. The results show that the production-weighted average rate of fall in production has fluctuated significantly over time, but has been relatively more stable since the 1980s, at around 5% to 12% per year (Figure 10.8).

Short-term fluctuations appear to reflect the impact of the production policies of OPEC countries and cyclical changes in investment in existing fields, resulting from policy, geopolitical factors and fluctuations in oil prices and fiscal terms. The very rapid fall in production in 1980 is explained primarily by the collapse in output at several fields in Iran following the Iranian revolution in late 1979, while the invasion of Kuwait, which

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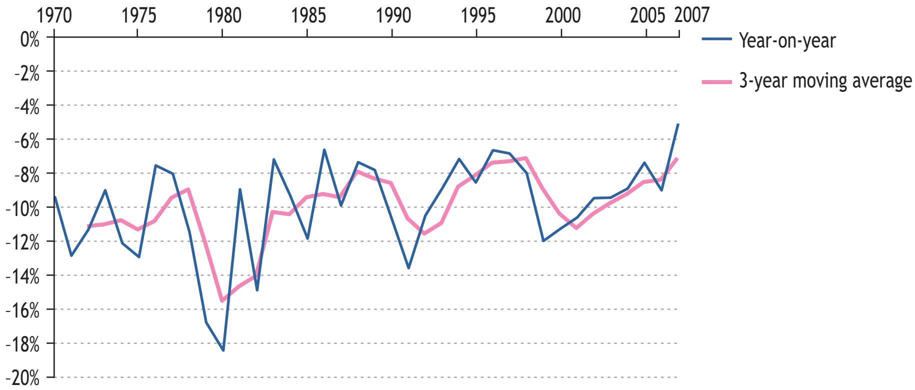
led to the loss of all of the country's production for several months, caused the drop in output to accelerate in 1990 and 1991. The acceleration in the year-on-year rate of fall in production in the late 1990s was the result of a downturn in upstream investment, in response to a slump in prices, while the fall in the rate of decline since 2000 (with the exception of 2006, when production constraints in OPEC countries caused average rates of decline to accelerate) appears to have resulted from higher capital spending on re-developing existing fields.

Figure 10.8 • *Year-on-year change in the production-weighted average production from post-peak fields*



Note: In contrast to the decline rates shown in the preceding tables and figures, which are based on the average decline rate of each field over a period of time determined by its peak or plateau, the rates of change shown here are calculated using simple year-on-year changes in each field's production. For each year, the dataset is adjusted to include only those fields that were in the post-peak phase and that were in decline in that year. As a result, the sample size diminishes going backwards in time. For example, the number of fields that were post-peak in 1970 was 36 compared with 580 in 2007. The decline rates may therefore be considered less representative of all rates for all the world's producing fields for the earliest years than for 2007.

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

Deriving an estimate of the average global observed decline rate

Our field-by-field analysis of decline rates allows us to obtain a reasonable estimate of the average decline rates for all the fields in the world, weighted by production. All the decline rates presented so far in this chapter are based on field-by-field production data from our database, covering 798 fields. The average size of these fields – predominantly super-giants and giants – is significantly larger than the average size of *all* the fields in the world. The 580 fields included in our analysis of post-peak decline rates produced 40.5 mb/d of crude oil in 2007 – equal to 58% of world production. Yet these fields make up less than 1% of all the producing fields in the world.

It is impossible to know precisely what the observed decline rates are for these other fields. Nonetheless, it is reasonable to assume that the decline rates are, on average, at least as high as these of the large fields in our database. In reality, they are likely

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to be somewhat higher, given that we have detected a clear correlation between field size and the observed decline rate. In order to derive an indicative estimate of the overall decline rate for *all* the world's oilfields, we have assumed that the average rate for the fields not included in our database is the same as that for the large fields (which averages 10.4% worldwide). This is a somewhat optimistic assumption, as the differences in decline rates between the three categories of fields we assess here suggest that smaller fields are likely to have higher decline rates than large fields. On this basis, we estimate that the average observed decline rate worldwide is 6.7%. Were that rate to be applied to 2007 crude oil production, the annual loss of output would be 4.7 mb/d. The adjusted decline rate is higher in all regions, markedly so in North America, because our sample for that region is dominated by super-giant and giant fields (Table 10.12).

Table 10.12 ● *Estimated production-weighted average annual observed post-peak decline rates for all fields worldwide by region*

	Based on 580 field dataset	All fields
OECD North America	6.5%	9.7%
OECD Europe	11.5%	11.9%
OECD Pacific	11.6%	12.6%
E. Europe/Eurasia	5.1%	5.8%
Asia	6.1%	6.7%
Middle East	2.7%	3.4%
Africa	5.1%	6.8%
Latin America	6.0%	6.6%
World	**5.1%**	**6.7%**

Sources: IHS, Deloitte & Touche and USGS databases; other industry sources; IEA estimates and analysis.

Trends in natural decline rates

Estimating historical trends

Observed decline rates are an important indicator of the performance of oilfields across regions and over time, but, by themselves, they do not reveal underlying trends in field production behaviour. This is because observed rates are heavily influenced by on-going and periodic investment in fields already in production, aimed at maintaining well pressure and flow rates, and improving recovery of oil reserves. In reality, few oilfields are left to produce without further field-development work involving significant amounts of capital expenditure once the initial set of wells has been drilled. This further investment can take the form of infill drilling (to target pockets of oil that prove to be inaccessible from existing wells), well work-overs (major maintenance or remedial treatments, often involving the removal and replacement of the well casing), secondary recovery programmes such as water flooding (the injection of water to push the oil towards producing wells) and gas injection and enhanced oil recovery techniques, such as CO_2 injection. Such activities can arrest the natural decline in

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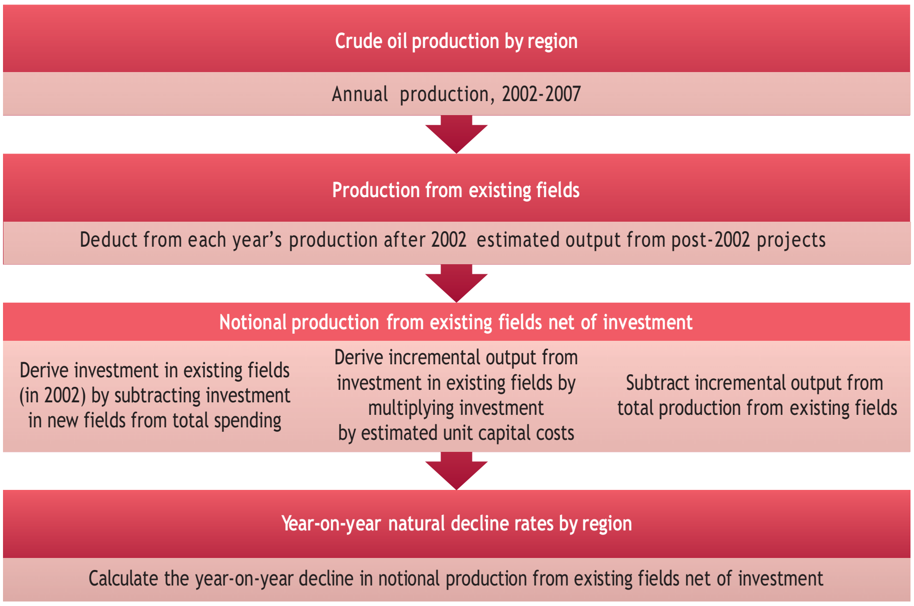
pressure and production from a field and may even boost output to a significant degree. It is necessary to estimate the underlying, or *natural* decline rate – the rate at which production at a field would decline in the absence of any investment – in order to ascertain how much capital needs to be deployed to sustain production or limit observed decline to a particular rate.

To arrive at the natural decline rate, therefore, one needs to strip out the effect of new investment beyond the initial capital spending involved in bringing the field into production. We have developed a top-down methodology for estimating historical natural decline rates, based on the estimated impact of the actual investment that has gone into existing fields over the past five years (summarised in Figure 10.9). This approach required detailed estimates of the amount of new capacity coming into production each year over 2003-2007, the associated capital expenditure and the unit cost of incremental capacity at existing fields, based on generic (region-by-region) estimates of finding and development costs and reserve life estimates (drawing on the results of our analysis of investment in Chapter 13). The results were calibrated against our estimates of observed decline rates for all fields worldwide. Inevitably, a degree of judgment was involved, in consultation with industry, in estimating these parameters, given data deficiencies. The results must, therefore, be considered as indicative only.

Figure 10.9 • *Methodology for estimating natural decline rates*



The production-weighted average annual *natural* decline rate for the world as a whole is estimated at 9.0% – some 2.3 percentage points higher than the *observed* decline rate for post-peak fields. In other words, the decline in production from existing fields would have been around one-third faster had there been no capital spending on those fields

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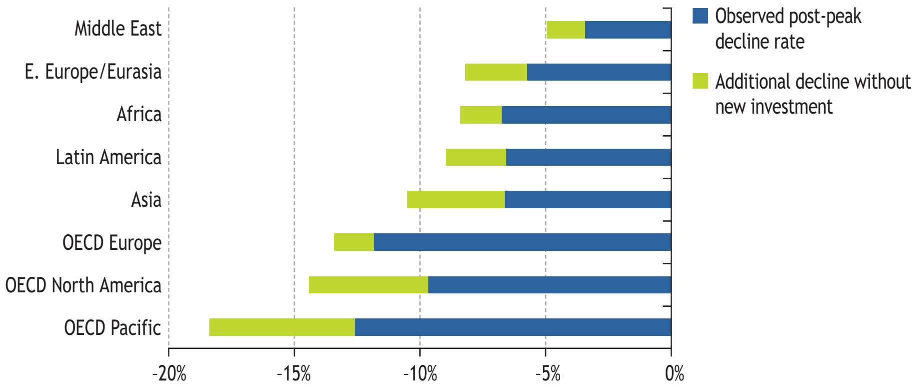
once they had passed their peak. Natural decline rates are highest for OECD Europe and Pacific (Australia), and Asia. The rate is lowest for the Middle East. The difference between observed and natural decline rates varies in both absolute and proportionate terms across regions (Figure 10.10). Nonetheless, the ratio of observed to natural decline rates, which averages about 1:1.3, is broadly similar across all regions, suggesting that these estimates are reasonably robust. The smallest difference between observed and natural rates is for Europe (North Sea). This appears to reflect the relatively limited remaining scope for infill drilling compared with other parts of the world.

Figure 10.10 • Indicative natural decline rates by region



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Discerning a trend from the short time period we used to estimate natural decline rates is risky. Nonetheless, a clear rising trend does emerge from our analysis: the worldwide average natural decline rate (year-on-year) rose from 8.7% in 2003 to 9.7% in 2007 (the average rate is 9% for the period 2003-2007 as a whole). This result is in line with expectations, as over that period, a growing share of crude oil production came from younger, smaller and offshore fields, which have inherently higher decline rates. Smaller and offshore fields typically exhibit higher observed decline rates, because of the more limited potential for infill drilling, as mentioned in the previous section. But natural decline rates would also be expected to be higher too, as these fields tend to be developed in such a way as to maximise and bring forward peak production in order to improve cash-flow and amortise the large up-front investment as quickly as possible. Development programmes for larger fields typically are less likely to be driven by purely financial considerations and are more likely to be effected by a policy of maximising ultimate recovery rates.

Other recent studies support the finding that natural decline rates have been rising. For example, the natural decline rates of fields operated by 15 major oil companies rose on average from 10.6% to 13% between 2001 and 2006 (Goldman Sachs, 2007). The higher rate for these companies is to be expected, since a relatively large share of their production comes from OECD regions (notably North America) and West Africa, where decline rates are highest. The increase in the overall rate of natural decline, based on our analysis, is far from negligible: based on world crude oil production of 70.2 mb/d

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in 2007, this increase represents an additional annual loss of capacity through natural decline of around 700 kb/d. The implication is that an additional 700 kb/d of gross capacity — the equivalent of almost one-and-a-half projects the size of Khursaniyah in Saudi Arabia — had to be brought on stream in 2007 simply to offset the higher rate of natural decline compared with five years before.

Case studies of how individual fields have behaved in the absence of any major investment provide a way of verifying the extent to which natural decline rates deviate from observed rates. In reality, there are few cases where a field has been left to decline over a long period without any capital spending whatsoever. Some cases can, nonetheless, be identified. The collapse of the Soviet Union caused upstream investment virtually to dry up for several years in the first half of the 1990s and led to a precipitous drop in oil production. During 1990-1995, the production-weighted average annual decline rate for the 19 largest Russian fields (with reserves in excess of 1 billion barrels) that were in decline at that time was close to 14%, though decline rates were certainly exaggerated by a lack of spending on operation and maintenance, too. Among those fields, Samotlor — the world's sixth-largest in terms of initial reserves — experienced a year-on-year production decline of more than 16% over the same period.

Among all the North Sea fields in our dataset, we have identified only nine that were not subject to any major development programme over a period of at least three years (the majority of fields have been developed in a continuous fashion, with sustained capital spending over much of the life of the field). The (arithmetic) average decline rate is 13.7% for all the fields in this sample (Table 10.13), which is very close to the natural decline rate we estimate for all North Sea fields (which make up virtually all of Europe's production) based on 2002-2007 data. Decline rates among the nine fields range from under 6% to over 20%.

Table 10.13 • *Average year-on-year decline rates for selected North Sea oilfields*

Field	Country	Initial oil reserves (million barrels)	Period of production without significant investment	Average decline rate*
Fulmar	UK	583	1997-2006	13.2%
Miller	UK	345	1998-2000	23.1%
Murchison	UK	332	1985-1989	20.3%
Ninian	UK	1 310	1994-1996	13.2%
Tern	UK	287	2003-2007	13.9%
Thistle	UK	433	1996-2002	12.0%
Auk	UK	197	1998-2003	5.7%
Skjold	Denmark	298	2004-2007	11.9%
Rijswijk	Netherlands	275	1969-1976	10.2%
Average (arithmetic)				**13.7%**

* Calculated as the cumulative average annual rate of decline between the first and last year of production over the specified period without significant investment.

Source: Official government data; IEA analysis.

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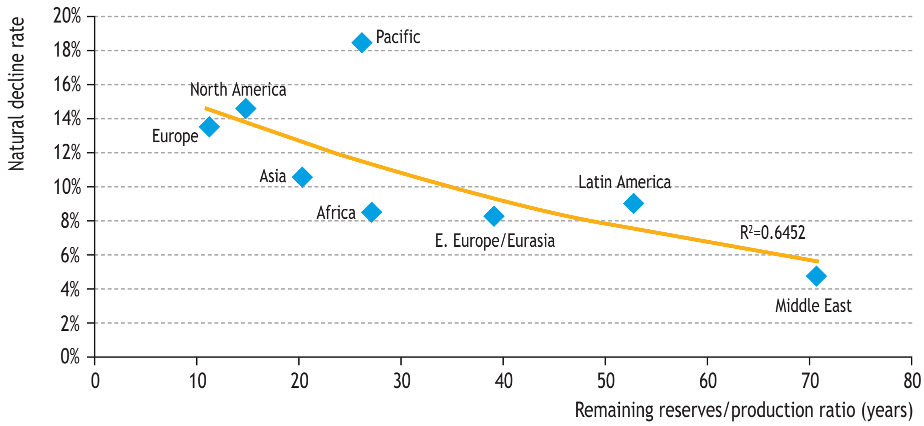
The apparent inverse relationship between field size and the natural decline rate mirrors that between the rate of depletion of recoverable reserves (measured by the ratio of remaining reserves to production, R/P) and the decline rate. The R/P ratio is inversely correlated with the natural decline rate at the regional level, even though we have only eight regional data points. The four regions with the lowest R/P ratio – OECD North America, Europe and the Pacific, together with Asia – have the highest natural decline rates, while the Middle East, with the highest R/P ratio, has the lowest decline rate (Figure 10.11). In short, the natural decline rate appears to rise over time as a producing region matures and the R/P ratio drops.

Figure 10.11 • Natural decline rates and reserves-to-production ratios by region, 2007



Note: Natural decline rates are production-weighted.

Sources: IHS databases; IEA databases and analysis.

Long-term prospects for natural decline rates

The scale of upstream investment required to match oil production to demand in the medium to long term hinges critically on the evolution of natural decline rates. The rate and type of investment, both in existing oilfields and in new fields, that will come on stream over the projection period will determine the extent to which observed decline rates diverge from natural rates.

There is little reason to suppose that, for a given type and size of field in a specific location, the natural decline rate will change significantly in the future. However, a change in the mix of fields that will be developed in the future, including a shift towards smaller reservoirs and offshore deepwater fields, would be expected to drive up natural decline rates over time in all regions. On the other hand, a larger share of new field developments over the projection period is expected to come from onshore locations in the Middle East, where natural decline rates are the lowest (mainly because the average size of fields is high). This factor will offset, at least partially, the effect of declining field size on the weighted-average natural decline rate worldwide.

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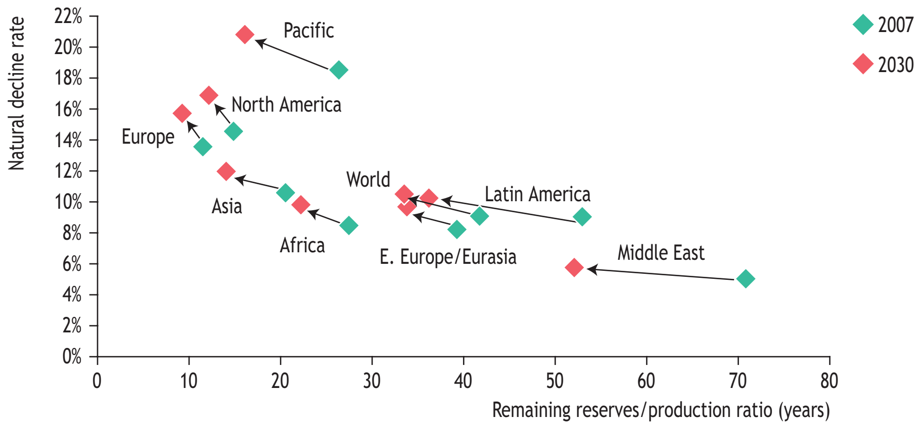
We have assessed, by region, how average natural decline rates weighted by production could change in the future, using our Reference Scenario projections of crude oil and NGLs production, and additions to proven and probable reserves through reserves growth and discoveries (described in detail in Chapter 11). The correlation between the R/P ratio and the natural decline rate is applied to the projected R/P ratio in each region to derive an estimate of how the natural rate in each case might evolve between 2007 and 2030 (Figure 10.12). The results suggest that natural decline rates will tend to rise in all regions. At the world level, the increase in the production-weighted average decline rate over the projection period is about 1.5 percentage points, taking the rate to around 10.5% per year in 2030. The increase is particularly pronounced in North America, where the natural decline rate increases from about 14% to 17%, while the R/P ratio falls to about 10 years (as remaining reserves fall even faster than production).

Figure 10.12 • Projected change in natural decline rates and reserves-to-production ratios by region, 2007 to 2030



Note: Natural decline rates are production-weighted.

Sources: IHS databases; IEA databases and analysis.

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