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Reprint Series Number 180

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The QUARTERLY REVIEW Of ECONOMICS And FINANCE

NORTH-HOLLAND The Quarterly Review of Economics and Finance 42 (2002) 335–372

Characteristics of North Sea oil reserve appreciation

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Received 21 August 2001; accepted 15 January 2002

Abstract

In many petroleum basins, and especially in more mature areas, most reserve additions consist of the growth over time of prior discoveries, a phenomenon termed *reserve appreciation.* This paper concerns crude oil reserve appreciation in both the UK and Norwegian sectors of the North Sea. It examines the change in reserves attributed to North Sea fields over time, seeking to reveal patterns of reserve appreciation both for individual fields and for groups of fields classified by potentially relevant common elements. These include field size, year of production start-up, geological age, gravity, depth and depletion rate. The paper emphasizes the statistical analysis of reserve appreciation. It contrasts the Norwegian and UK experience. An important distinction is drawn between appreciation of oil-in-place and changes in recovery factors. North Sea oil reserve appreciation between production start-up and the last observation year (usually 1996) is found to be substantial, but generally lacks a consistent profile. Appreciation recorded for the Norwegian fields on average is considerably greater than for the UK. Most UK appreciation is seemingly accounted for by oil-in-place; in Norway, from increases in recovery factors. However, UK recovery factors commence at much higher levels than those for Norway.

1. Introduction

In many petroleum basins, and especially in mature areas, most reserve additions consist of growth in already discovered fields. This phenomenon is termed *reserve appreciation.* For example, in the US from 1978 to 1991 reserve appreciation accounted for more than 90% of additions to proved reserves.[1] Hence, the nature and characteristics of reserve appreciation are crucial to understanding petroleum supply. Discovery size estimates require adjustment to reflect future field growth, otherwise the relative efficiency of recent exploration will be

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1062-9769/02/$ – see front matter
PII: S1062-9769(02)00133-3

undervalued. Moreover, as M. A. Adelman has shown, relationships between field development cost and reserve additions can serve as a proxy for finding cost.[2]

This paper concerns crude oil reserve appreciation in both the UK and Norwegian sectors of the North Sea, a province that accounts for about 2% of current world proven remaining oil reserves, 8% of production, and acts as a pricing fulcrum. Changes in field reserves are examined to see whether regular patterns of reserve appreciation are revealed for individual fields and for groups of fields classified by common elements.[3] These include field size, year of production start-up, geological age, gravity, water depth and depletion rate.

Field reserve growth in offshore areas such as the North Sea has not been investigated extensively, although the importance of appreciation was recognized in work by Odell and Rosing on North Sea reserves in the 1970s.[4] Some analysts have been skeptical about potential field growth in such regions, arguing that in high cost areas operators delineate fields more precisely prior to development.[5] Moreover, investment in pressure maintenance is more likely before production comes on stream, improving well productivity and economic viability. The associated higher recovery factor constrains the scope for reserve appreciation.

Primary emphasis in this paper is placed on the statistical analysis of reserve appreciation. A distinction is drawn between appreciation of oil-in-place—the oil contained in a field, whether recoverable or not—and the proportion estimated as recoverable (the recovery factor). This distinction turns out to be important. The paper does not attempt to discern the influence economic factors might have on appreciation patterns. Such factors could include prices, tax regimes, technological change, market structure, and different approaches among company operators.

I find that oil reserve appreciation in the North Sea is substantial, contradicting the view that appreciation of offshore fields may be negligible. As a fraction of reserves booked in the start-up year, however, it is not as marked as that in mature onshore areas. This in part does reflect earlier reserve recognition at production start-up, with prompt inception of pressure maintenance. Although appreciation among North Sea fields lacks any consistent profile, noticeable differences among groupings of reserves are disclosed.

The most important distinction to emerge is that between the UK and Norwegian sectors. Appreciation recorded for Norwegian fields is considerably greater than for the UK. In the UK, most appreciation appears to be accounted for by growth in oil-in-place; in Norway, from growth in recovery factors. However, recovery factors in the UK commence at much higher levels than those for Norway. Increases in Norwegian recovery factors are akin to catch-up to those recorded by the average UK field.

The paper is organized in six sections. Section 1 deals with background aspects: the definition of oil-in-place and recoverable reserves; the role of technology; the nature of development patterns; and data sources. Section 2 brings together key statistical features of the distribution of North Sea recoverable oil reserves. Section 3 examines patterns of reserve appreciation among fields and field groupings for the UK and Norwegian sectors. Section 4 looks at time profiles of reserve appreciation. Section 5 concerns the appreciation of oil-in-place and implied shifts in recovery factors. This section relies on confidential field data and the results presented are confined to certain aggregates. The conclusions of the paper are presented in Section 6. Throughout the text, reference is made to additional details available to the interested reader published in an earlier working paper (Watkins, 2000).

2. Reserves: background

The discussion below covers the distinction between oil-in-place, recoverable reserves and remaining recoverable reserves, differences between crude oil and natural gas reserve appreciation, and the role of technological change. Mention is also made of the means by which North Sea field development has given rise to reserve re-evaluation in the case of an example field.

The *recoverable oil reserve* is an estimate of how much oil at the surface a deposit would eventually yield.[6] *Oil-in-place* is the estimate of how much oil the deposit originally contained. These estimates are not fixed. They are subject to continual reappraisal. *It is the change in such estimates over time on which this paper focuses.* Remaining recoverable reserves are recoverable reserves less cumulative production to date.

2.1. Reserve components

Recoverable oil reserves are the product of two components: oil-in-place, and the recovery factor. Oil-in-place is the estimated amount of petroleum in a field, whether the oil can be brought to the surface or not. The recovery factor is the estimated fraction of the oil-in-place that could be brought to the surface over a field's effective life.

Oil-in-place can be thought of as the volume of oil bearing sediments less all the space not occupied by oil. The ability of oil to flow to the surface is affected by the inherent nature of the reservoir—its permeability and porosity, the amount of water as well as oil clinging to the rock, oil viscosity, various other physical factors, and above all by the physical reservoir drive mechanism propelling oil to the surface once the deposit is tapped.

To be more explicit, for a given field oil-in-place can be written as:

$$\mathrm{STOIP} = \mathrm{c} \times \mathrm{H} \times \mathrm{A} \times \mathrm{POR} \times (1 - \mathrm{SW}) \times \mathrm{SHR} \quad (1)$$

where

STOIP	=	oil-in-place measured at the surface (stock tank barrels)
c	=	a constant converting acre-feet to barrels (or tonnes)
H	=	pay thickness
A	=	acreage
POR	=	porosity of the rock
SW	=	water saturation ($1 - \mathrm{SW} = $ oil saturation)
SHR	=	shrinkage factor in bringing oil to the surface.

Eq. (1) is expressed as if oil were recovered at the surface; the shrinkage factor accounts for the difference between measurement underground at reservoir temperature and pressure, and that at the surface. Shrinkage mainly arises because underground oil is swollen by dissolved gas. At atmospheric pressure these liquids become gas, reducing the volume of liquids.

Recoverable reserves are:

$$\mathrm{INRES} = \mathrm{RF} \times \mathrm{STOIP} \quad (2)$$

where

INRES = recoverable oil reserves (stock tank barrels)
RF = recovery factor.

A distinction can be drawn between primary, secondary and tertiary recovery. The primary recovery factor is that expected to prevail without any action by the field operator—in other words if the field were depleted naturally. Secondary and tertiary recovery factors are those anticipated were the natural drive mechanism augmented by production practices and investment intended for that purpose. Typically these are schemes to maintain reservoir pressure by water injection. Measures to increase eventual recovery are termed enhanced recovery (ER) schemes.

Oil-in-place is governed by a field's natural physical configuration, as is evident from Eq. (1). It follows that field delineation and information gathered over time on field properties mainly account for revisions to estimates of oil-in-place. Estimates of the recovery factor can also be affected by field delineation. But they are more fundamentally affected by the kind of reservoir development plan pursued and by implementing advances in field technology, allied to accumulation of knowledge about production performance. The crux of the matter is that the dynamics of appreciation of "in-place" reserves may well differ from those governing changes in recovery factors.

Hence, if the data permit it is preferable to breakdown appreciation of recoverable reserves between oil-in-place and recovery factor components. The two elements are not independent. Both are affected by knowledge garnered as reservoir development and depletion proceed.

2.2. Oil and natural gas reserve appreciation

This paper concerns oil. The scope for oil reserves appreciation usually exceeds that for natural gas. This mainly represents inherent differences in primary recovery factors, which for oil are typically around 30%, for gas around 80%. Most increases in gas reserves reflect increases in gas-in-place from extensions in field contours and reassessment of field properties. Increases in oil reserves reflect both increases in oil-in-place and in the recovery factor. It follows there is more latitude for changing technology to affect oil reserve appreciation (examined in this paper) compared with that for natural gas. Such differences in reserve appreciation patterns are one of the reasons for excluding natural gas reserves contained within the oil fields examined in this paper.

2.3. Technological change

Over the past decade or so changes in technology have been especially noticeable. The "big three" have been 3D seismology, horizontal and directional drilling, and deep water production systems.[7] One stimulus behind such innovations has been relatively weak or stagnant oil prices since the mid-1980s until recently, in conjunction with a more competitive industry structure that has placed a high premium on cost efficiency.[8]

New technologies have *inter alia* improved drilling success rates, increased reservoir recoveries, and extended exploration prospects. In short, petroleum productivity has risen. The incidence, timing and nature of technological development influence the scope for reserve appreciation.

"New technology" is a broad term, embracing not only hardware embodying new techniques, but also new information systems and modeling techniques. Recent North Sea examples are mentioned below.[9]

The "Seisbit" system measures the noise of a working drill-bit as a down-hole method of compiling seismic information. Its benefits include minimization of rig downtime, lower operational risks for both exploration and appraisal wells, and increased accuracy in assessing rock properties in the neighborhood of the well.

Multilateral wells replace two single wells by a dual well without compromising production rates or reserves, and also reduce pressure on available drilling slots. Application to the Forties field in the North Sea entailed development of an adjunct technology called "through tubing drilling" enabling drilling via production tubing. This allows small remaining targets in mature fields to be targeted. The system is reported as being applied successfully to eight platforms and three subsea wells in the North Sea (Smith Rae, 1999, p. 42).

Optimal reservoir management requires up to date information on the distribution of field fluids. Time dependent measurements improve the accuracy of reservoir models. 3D seismic measurements provide interwell data. Four dimensional (4D) seismic images (3D plus time) can map fluid changes in a field, hence improving predictions of field parameters offered by simulations. The technique can lead to identification of bypassed oil and undrained reservoir niches. It has been applied by Statoil to the Gullfaks field to improve drainage by drilling a horizontal well, increasing recoverable reserves (Smith Rae, 1999, p. 149).

The ability of new and modified technologies to be brought to maturity has been enhanced by techniques that improve well drilling, completion, operation and evaluation. Two aspects are involved: improvements in reservoir modeling; and introduction of new well equipment. The 'Simpler' process is an organizational approach to drilling operations, resulting in significant cost reductions.

Improvements in seismic technology may well have a greater impact on assessments of oil-in-place than on recovery factors. Changes in drilling technology might have more relative impact on the recovery factor. Thus the nature and incidence of technological developments could have a differential impact on appreciation by reserve component.

2.4. Field development patterns: an example

Mention has been made of how field delineation and production history can lead to continual reserve re-evaluation, in addition to that from introducing new technology. A good example of this is provided by the history of one now depleted field in the UK sector.[10]

Production started a decade after discovery. Abandonment was expected some 25 years later. Appraisal drilling commenced late 1973. One geologic interval tested 10,800 b/day, another 750 b/day. A well drilled to the north of the discovery well found only thin net oil pay. A final appraisal well drilled in 1978 flowed 5,300 b/day.

Development drilling started in 1979 and continued until early 1983. A production platform was installed to handle output from 12 wells. The natural water drive was boosted by six water injection wells—an example of immediate inception of ER. One development well discovered another reservoir. Peak production was reached in 1984. Subsequently, production wells that watered out were converted to injectors or side tracked to deeper targets.

Understanding of the field paralleled growth in the geophysical, geological and reservoir database. The first (two dimensional) seismic data were obtained in 1970. Further 2D data were acquired, but did not induce significant changes in the structural maps. More seismic data were obtained in 1978, confirming the prevailing geological model.

The first reservoir simulation model was constructed in 1974, and updated in 1976. Further sensitivity studies on water injection were made in 1977; at that time, geological reinterpretation reduced the estimated stock tank oil-in-place (STOIP). In early 1982 a large amount of new data became available, revising field intepretation. The estimated STOIP rose.

By early 1985, data were available from 19 development wells, 18 months of production information, and from the reprocessing of an earlier 2D seismic survey. The new information indicated increases in STOIP and recoverable reserves. The geological model was revised. The STOIP rose further. The reservoir simulation model was updated in 1987 and indicated an increase in the recovery factor. New 2D seismic data were obtained in 1988. One observation well was side tracked and discovered another reservoir within the field.

By the mid 1990s significant advances were made in field information, particularly in geophysical acquisition and processing, and in high resolution biostratigraphy. In 1994 a 3D survey was acquired over the whole block. A revised geological model was developed. Both the STIOP and recovery factor increased. The results of the geoscience studies in 1995 and 1996 indicated possible targets for infill drilling. The fluid lifting mechanism changed after 1994. Electrical submersible pumps were installed in 5 producing wells. This generated incremental reserves. A horizontal well drilled in November 1996 confirmed the area reached had been swept.

This field history illustrates how reserve appreciation has taken place over a considerable period of time as a function of:

- reservoir development and performance providing new information;
- recalibration of field engineering and geological models in light of new knowledge;
- investment in, and application of, new technology.[11]

The inception of enhanced recovery techniques at production start-up is noteworthy. The estimated recovery factors fell within a fairly narrow band. Most of the field reserve appreciation related to increases in STOIP. As seen later (Section 5), this pattern seems to be quite typical of fields in the UK sector.

2.5. Data sources

The two primary sources of data were various issues of the UK ‘Brown Books’ compiled by the Department of Trade and Industry (DTI), and corresponding publications of the Norwegian Petroleum Directorate (NPD). These were supplemented by confidential information from the NPD, and from some company sources in the case of the UK.[12]

One data problem is lack of a standard definition of reserves across countries. For example, since reserve definitions used internationally are often not as tight as those for the US and Canada, care has to be exercised in comparing reserve growth factors across jurisdictions—broader reserve definitions may already include reserves that in other regions would be added as part of the appreciation process. Stricter definitions in the U.S.A. and Canada are based in part on US SEC requirements.[13] Differences in reserve reporting standards are mentioned further in Section V.

3. North Sea recoverable reserves: statistical features

This section describes the key statistical features of the North Sea oil fields. The observation period ended in 1996; fields coming on stream after that year are excluded. For the great majority of fields the last observation year is 1996. But for nine fields in the UK, and one in Norway, production terminated earlier.[14]

The field population examined consisted of 96 in the UK sector and 30 in the Norwegian sector—a total of 126 fields. All are developed (undeveloped discoveries were omitted). The comments below relate to the distribution of field reserves characterized by size, water depth, oil gravity, production life, depletion rates, and geological age.

3.1. Recoverable reserves

As discussed beforehand, estimates of total recoverable reserves—recoverable reserves thought to be present before extraction commences—are continually revised in light of evidence provided by production performance, and by field development. Such revisions may be up or down. Figs. 1 and 2 show histograms of field total recoverable reserves assessed *at the time of first commercial production (start-up)* for the UK and Norwegian sectors respectively.

Summary statistics are brought together in Table 1 below. The average field reserve size in the UK is less than half that of the average Norwegian field, whether at production start-up or last observation year. And by the last observation year the ratio approaches one third (0.36), reflecting greater reserve appreciation in Norway. Moreover, the coefficient of variation is appreciably smaller for the Norwegian fields compared with the UK.

Entries for recoverable reserves in the upper and lower panels of Table 1 show average appreciation factors for recoverable reserves (weighted average field appreciation) by the last observation year as 1.22 for the UK, 1.47 for Norway, and 1.32 for the combined sectors. In other words, the average field in the UK shows recoverable reserves rising by about 20% over an average interval between start-up and the last observation year of some eight years. But in Norway the corresponding degree of appreciation approaches 50%, with an average production life similar to the UK at about nine years. As long as reserve definitions, appraisal techniques and the average appreciation interval are reasonably comparable, this difference between the two sectors is undoubtedly marked.[15]

The UK data contain 16 fields that commence production in 1996, and no growth in recoverable reserves is shown between start up and year end: the appreciation factor for these fields is unity. In Norway, only one field is in this category. If the UK fields were confined to the 80 commencing production before 1996, the mean recoverable reserve at start-up would be 190 mmbbls, and 235 mmbbls in the last observation year, yielding an appreciation factor of 1.24, much the same as for all 96 fields. If the single field with start-up in 1996 were

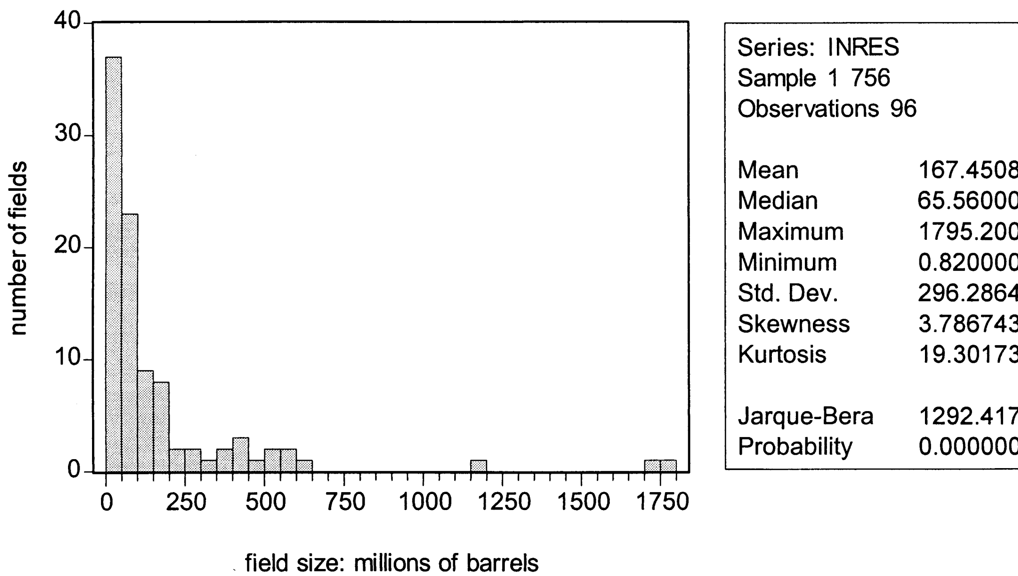

Fig. 1. Initial reserves in start-up year: UK sector.

excluded from the Norwegian sample, the mean recoverable reserve at start-up is 394 mmbbls, 579 mmbbls in the last observation year: the appreciation factor is 1.47 (the same as for all 30 fields). Hence the difference in average reserve appreciation between the UK and Norway is not materially affected by the greater relative incidence of UK fields commencing production in 1996.

3.2. Distribution of field size

What of the shape of the frequency distributions of field total recoverable reserves measured at start-up and the last observation year? All show significant positive skewness (see Figs. 1 through 6). That is, there is a great preponderance of small fields, and there are several large fields.[16] Not surprisingly, the hypothesis that the field distribution conformed to normality was decisively rejected (using the Jarque-Bera test).

Often, the size distribution of fields in various petroleum basins around the world is found to be consistent with a skewed distribution such as the lognormal. The distribution of the (natural) logarithm of North Sea field size was no exception. In all instances, the hypothesis of lognormality would not be rejected.[17] In short, there is nothing especially distinctive about the size distribution of fields in the North Sea basin. Its shape broadly conforms to that found elsewhere.

The cumulative distribution curve shows that a minority of fields account for the majority of the aggregate reserves. In terms of initial reserves at start-up, for the UK sector the largest five fields account for 37%, the largest 10 for 52%, and the largest 20 for 71% of total reserves. In the Norwegian sector, the largest three fields account for 31%, the largest six for

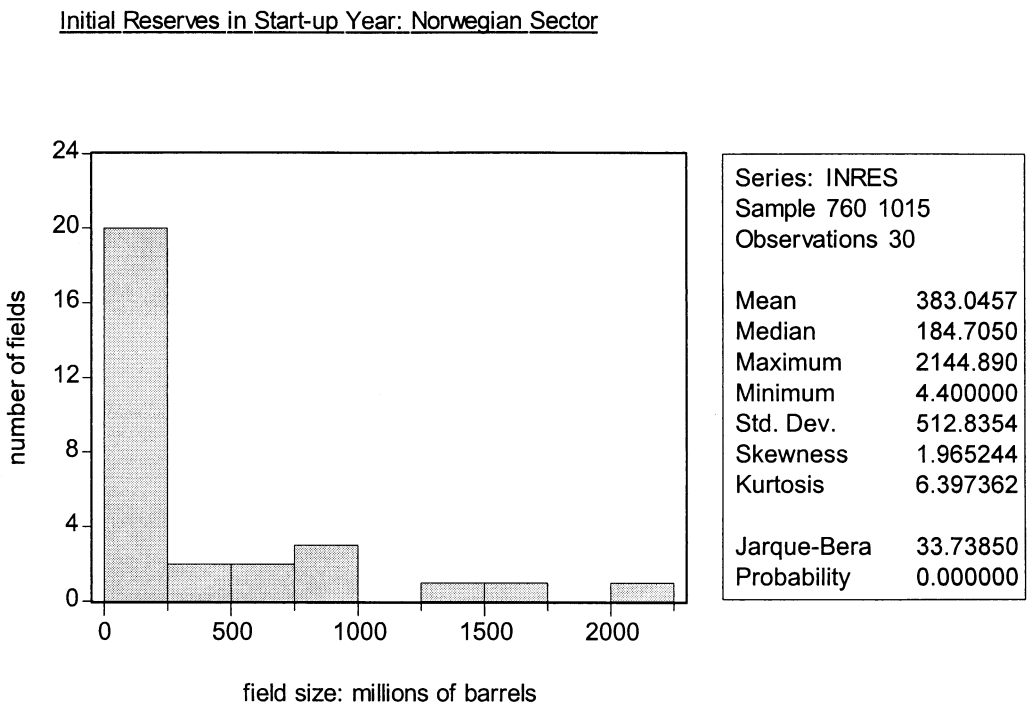

Fig. 2. Initial reserves in start-up year: Norwegian sector.

47%, and the largest 12 for 61% of total reserves. In short, there is a heavy concentration of recoverable reserves in the larger fields. Details are shown in Table 2.[18]

3.3. Gross reserve appreciation[19]

The difference between reserves at start-up and those in the last observation period shows total appreciation recorded between these two dates. Table 3 below provides summary

Table 1
North Sea recoverable oil reserves: summary statistics

Sector	At production start-up (1) Number of fields	(2) Mean mmbbls	(3) Std. dev mmbbls	(4) Coeffic of variation (3)/(2)
UK	96	168	296	1.8
Norway	30	383	513	1.3
Both sectors	126	219	369	1.7
	In last observation year[a]			
UK	96	205	397	1.9
Norway	30	561	837	1.5
Both sectors	126	290	553	1.9

[a] 1996 or year when field is shut in.

Table 2
Size concentration of recoverable reserves at start-up

UK sector (96 fields)	millions of barrels	Norwegian sector (30 fields)	millions of barrels
Sum of all fields	16,075	Sum of all fields	11,491
Top 5 as%	37	Top 3 as %	31
Top 10 as %	52	Top 6 as %	47
Top 20 as %	71	Top 12 as %	61

statistics. It shows that the differences between the UK and Norwegian sectors found in Table 1 are accentuated in terms of gross reserve appreciation. Average field appreciation in Norway is nearly five times that for the UK. Although the standard deviation for Norway is 2.7 times that in the UK, the Norwegian coefficient of variation is considerably lower. These results reflect in part the much greater incidence of smaller fields in the UK (developed) field population, an incidence affected by greater incentives in the UK tax system to bring such fields on line, compared with Norway.[20]

3.4. Distribution of reserve appreciation

Figs. 3 and 4 are histograms of field gross appreciation for the UK and Norwegian sectors respectively. The distributions do not conform to normality; the Jarque-Bera tests do not reject the hypothesis of lognormality.[21]

The cumulative distribution of reserve appreciation for fields with positive values (see Table 4 below) shows that in the UK sector the five fields recording the largest reserve appreciation accounted for 63%, the largest 10 for 79%, and the largest 20 for 93% of total reserve appreciation. In Norway, the largest three fields account for 62%, the largest six for 84%, and the largest 12 for 98%. These results show a greater degree of concentration for reserve appreciation than for recoverable reserves.

I now turn to the distribution of reserves in terms of various key field characteristics. These include: production life; water depth; gravity; depletion rate; and geological age. The main statistical measures for the first four of these characteristics are shown in Table 5.

Table 3
North Sea gross reserve appreciation: summary statistics[a]

Sector	(1) Number of fields	(2) Mean mmbbls	(3) Std. dev mmbbls	(4) Coeff of var (3)/(2)	(5) Apr factor
UK	96	37	143	3.8	1.22
Norway	30	178	390	2.2	1.46
Both sectors	126	71	233	3.3	1.32

[a] Appreciation calculated as difference between initial reserves at start-up and initial reserves in the last production year.

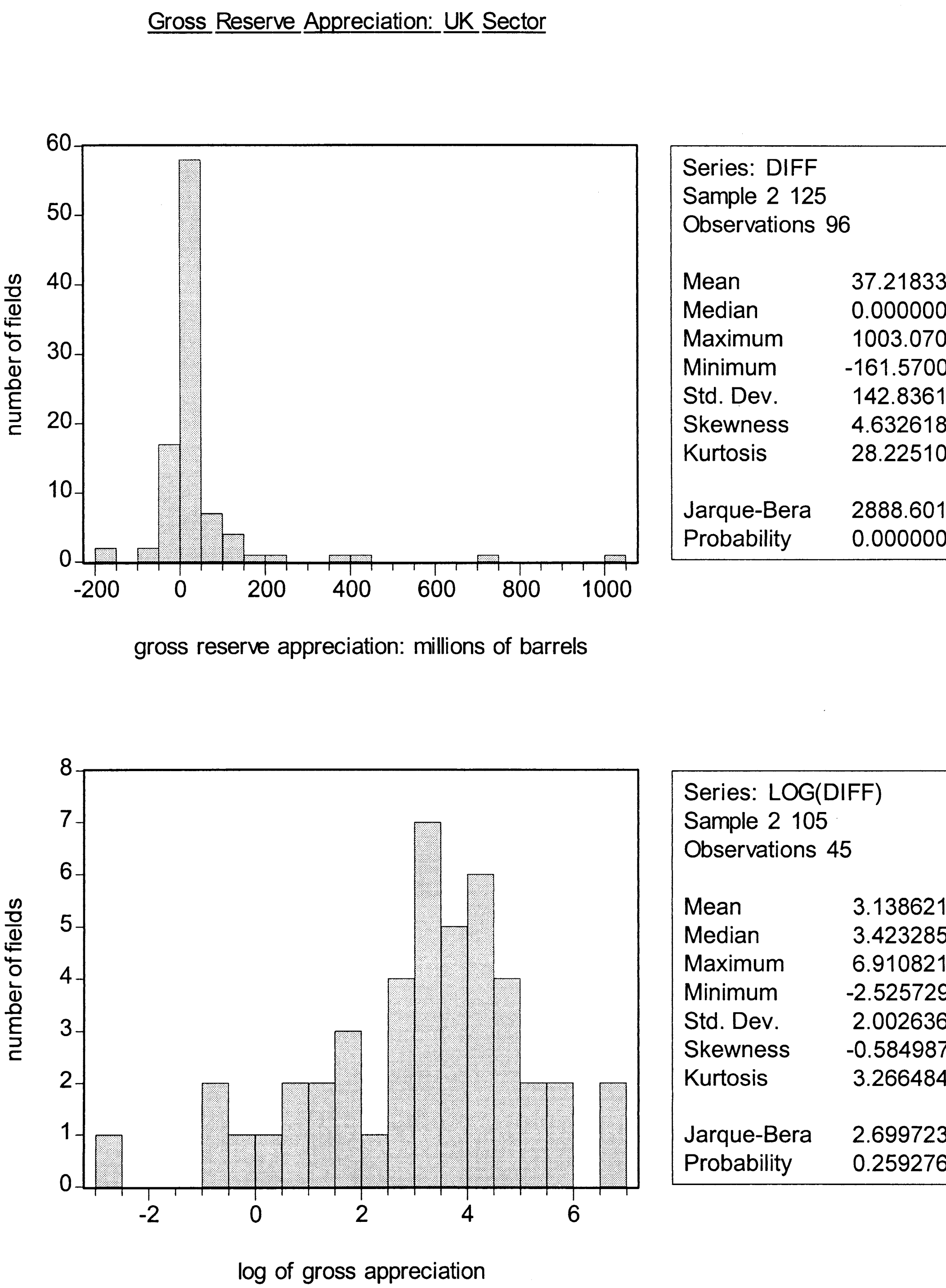

Fig. 3. Gross reserve appreciation: UK sector.

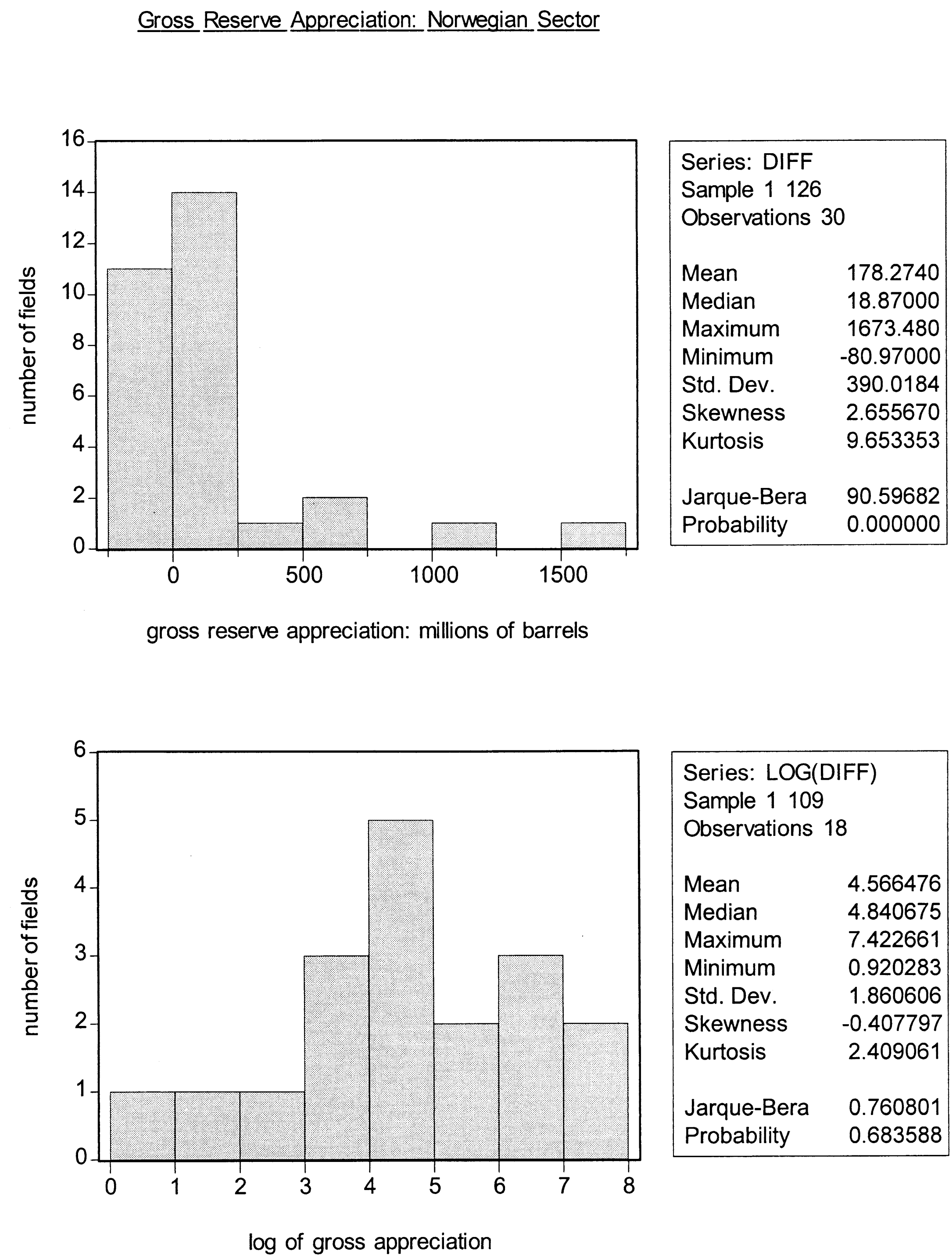

Fig. 4. Gross reserve appreciation: Norwegian sector.

Table 4
Size concentration of reserves appreciation[a]

UK sector (96 fields)	millions of barrels	Norwegian sector (30 fields)	millions of barrels
Positive sum of all fields	4,317	Positive sum of all fields	5,632
Top 5 as %	63	Top 3 as %	62
Top 10 as %	79	Top 6 as %	84
Top 20 as %	93	Top 12 as %	98

[a] Confined to positive values.

3.5. Distribution by production life

The distribution of fields according to the number of years on production (production life) is far from uniform for either sector, with the majority of the fields being young. The median age for the UK is five years; for Norway it is somewhat older at seven years. If field age were weighted by initial reserves at production start-up, the resulting weighted average is 14 years for the UK, 11 for Norway, indicating a predominance of recoverable reserves in older fields for both sectors. This illustrates the tendency to find the larger fields earlier in exploring a basin.

3.6. Distribution by water depth

The average field water depth in the UK sector is about 120 meters.[22] A spread of only 100 meters, from 70 to 170 meters, covers the great majority of the distribution. The average field water depth in the Norwegian sector is somewhat deeper than for the UK at 140 meters, and with a much more extensive range.

Table 5
Statistics of field characteristics

	Mean	Median	Std dev	Skewness	Kurtosis
UK					
Age (years)	7.9	5.0	6.5	0.7	2.2
Water dep(m)	120.3	126.5	32.9	−0.7	3.7
Gravity (degr)	37.0	37.9	4.6	−1.4	6.7
R/P ratio (yrs)[a]	9.2	5.7	8.7	1.8	5.7
NORWAY					
Age (years)	9.4	7.0	7.2	0.6	2.1
Water dep(m)	139.8	100.5	91.9	1.1	2.8
Gravity (degr)	37.7	38.0	3.8	−0.8	3.6
R/P ratio (yrs)	6.6	5.6	4.6	−0.3	2.5

[a] R/P measured in last observation year (usually 1996).

3.7. Distribution by gravity

The field distribution by gravity, in terms of API degrees, for the UK sector has mean and median values much the same at 37 and 38 degrees, respectively.[23] Few fields are of heavy gravity—in fact only four fields are less than 30 degrees. The majority of the distribution is in the medium range of 34 to 40 degrees. If the field gravities were weighted by initial reserves at production start-up, the resulting weighted average gravity is 36 degrees, close to the unweighted average.

The distribution for Norway shows average (and median) field gravity of 38 degrees, virtually the same as that for the UK. A range of six degrees, from 34 to 40 degrees, covers about 70% of the distribution.

3.8. Distribution by depletion rate

The depletion rate is represented by the ratio of remaining recoverable reserves to production for a given year, termed the reserves to production ratio (RPR). The distribution of RPR was examined for 1996. The number of UK fields in the sample is 82 (after exclusion of those with RPR's greater than 50 or less than unity); the corresponding number for Norway is 28. The respective mean RPRs are 9.2 and 6.6 years, suggesting an appreciably faster average depreciation rate for Norway than for UK fields. But that result is heavily influenced by a few high field RPRs in the UK sector: the median values at 5.7 years (UK) and 5.6 years (Norway) are close.

Lognormality of RPRs is not rejected for either sector. This result contradicts any presumption that deliverability requirements—which often arise in the case of natural gas—might induce a degree of constancy in RPRs across fields. That is, there is little reason to suppose a priori that the depletion rate would be heavily skewed. As seen earlier, lognormality would not be rejected for the distribution of recoverable reserves, or for annual production by field (at least for the one year examined, 1996). But it does not follow that the ratio of remaining reserves to production in 1996 necessarily would be lognormal.[24]

3.9. Distribution by geological age

Whether in terms of initial reserves or number of fields, rocks of the Jurassic age predominate in the UK sector. The only other individual age of note is the Tertiary. In particular, 47 fields of the 96 in the UK sector are of Jurassic age, accounting for 62% of initial reserves at production start-up.

For Norway, the geological distinction drawn is that between the Cretaceous (mainly chalk) and the Triassic/Jurassic/Tertiary age (mainly sandstone). Nine fields of the 30 in the Norwegian sector are chalk, the remainder sandstone.

4. Reserve appreciation patterns and profiles

Analysis in the preceding section showed average reserve appreciation in the Norwegian sector of the North Sea considerably exceeding that in the UK sector. I now look at the appreciation experience of individual fields, and of fields grouped by the various characteristics mentioned beforehand (size, gravity, water depth, depletion rate, geological age, and production life). Such experience is examined both in overall terms and as time series (profiles). The latter will shed light on whether revisions to reserves are possibly random corrections or whether they reveal regularity.

4.1. Factor definition

As indicated in section 2, the reserve appreciation factor is calculated with reference to recoverable reserves, not remaining reserves.[25] The denominator of the appreciation factor is the recoverable reserve booked at the time of first commercial production (start-up). The numerator is the recoverable reserve booked in the years following start-up. That is:

$$AF_t = INRES_t/INRES_1 \tag{3}$$

where:

AF_t = appreciation factor
$INRES_t$ = recoverable reserves, year t
$INRES_1$ = recoverable reserves in start-up year, designated year 1.

The reserves entering the formula could be the reserves for an individual field, or a summation of fields by some common characteristic.

For new discoveries outside of North America, field output—especially in offshore more remote areas—can often be delayed by lack of infrastructure to produce and transport the oil to market. Here, initial field size estimates may bear little relation to the size of the field used for production facility design. Time series of reserve estimates also generally reflect field development activity, driven by economic and market factors. Consequently, field growth functions will be affected by economic conditions.

In the North Sea, typically there is a substantial elapse of time between field discovery and production start-up. The apparent corollary is that adopting recoverable reserves booked at start-up as the denominator in Eq. (3) might omit substantial appreciation between discovery and start-up.

This issue was examined by looking at reserve data recorded in the UK "Brown Books." For many fields no information was available on reserve assessments prior to start-up. However, data were available for 22 fields. In all cases bar one, field reserves booked in years preceding start-up were either much the same or even higher than those booked when production commenced. No corresponding data were available for Norway.

On the basis of this albeit partial evidence it seems that using the start-up year as the base from which to measure trends in North Sea reserve appreciation does not omit significant appreciation between discovery and start-up. Rather, either there is no noticeable appreciation before start-up, or by start-up reserves have been revised downward, correcting earlier optimism. Moreover, if the interval period between field discovery and production start-up were long, as often holds offshore, the number of years since first production is a better grounded index of field development than the years since discovery.

4.2. Appreciation profiles

Appreciation profiles show booked recoverable reserves as a function of time elapsed since production start-up or year of discovery. Within any petroleum basin, such profiles tend to vary greatly. For example, in the case of Alberta, Canada, reserves discovered in 1955 increased about 75% over the first 10 years; those discovered in 1957 increased nearly 20 fold over ten years [see OGCB (1969,Table 5–3)]. In the US some reserve "vintages" show substantial and sudden growth as long as 70 years after discovery.[26] A good example here would be the impact of steam injection in Californian heavy oil reservoirs.[27] Repetition of such late growth would not be expected for more recently discovered oil and gas fields, or for offshore deposits such as the North Sea, where facility decommissioning would make re-entry prohibitively expensive or where ER schemes have already been introduced.

More generally, early implementation of extant or new technology—such as ER schemes—reduces the scope for later appreciation. The expense of offshore field development and rig availability encourages early introduction of pressure maintenance of which North Sea field development practice provides good examples.

Although an appreciation function normally trends upward, it need not be monotonic. Revisions to reserves can be negative or positive as knowledge about field performance accumulates and field parameters are reassessed.

The reasons for variability in appreciation whether by individual reservoir, field, geological play, basin or other characteristics, include:

- timing of the discovery within the discovery year or the timing of when the field comes on stream (the 'denominator effect');
- types of fields discovered (for example, the type of drive mechanisms);
- the geological formations in which discoveries are made;
- marketability (proximity and saleability);
- ownership (market access and investment requirements);
- incidence and nature of technological change.

And in high cost areas (such as offshore) there is a link between field additions and maturity of the infrastructure. The availability of production platforms and pipeline systems with unused capacity can make the development of marginal fields or reservoirs within a field profitable later on.

Many onshore fields in the 1950s and 1960s in North America suffered from market restrictions (prorationing), and geophysical information was inferior to today's. These factors tended to extend periods of appreciation in mature North American onshore areas, compared with what would have occurred under more recent conditions.

4.3. Reserve appreciation by individual field

Plots of reserve appreciation factors by field were published in Watkins (2000)).[28] The charts were confined to fields with more than four years of production history. The resulting number of fields plotted totalled 71, of which 53 were in the UK, 18 in the Norwegian sector.

A general observation is the great variety of reserve appreciation patterns displayed. But in broad terms, the plots for the 71 fields can be classified as follows: 39 showed appreciation factors that grew over time; 16 showed a quite flat trajectory; 11 were erratic; and five showed a declining trend. However, scrutiny of the charts reveals that the 39 fields with growing factors exhibit quite different 'steps'.

The conclusion is that the appreciation experience of individual fields in both countries is disparate. Although the majority of the fields with noticeable changes in reserves display a positive pattern, there is no obvious common trajectory. This comment is confirmed by the further statistical analysis to which fields displaying positive growth were subjected, reported in Section 5.

I now look at whether greater regularities in reserve appreciation emerge when reserves are grouped by some common characteristics. In what follows, the calculation of appreciation factors aggregates estimates of total recoverable reserves by year for a given category and divides that by the corresponding aggregate recoverable reserves at start-up. The first such classification is by common year of production start-up, termed "vintage."

4.4. Reserve appreciation by vintage

Vintage refers to the year in which field production commences. Recoverable reserves for fields with the same year of production start-up were aggregated and tracked over time to the last observation year, providing "vintage" appreciation profiles. The calculation of appreciation factors for each year after start-up by aggregating data for the relevant group of fields is equivalent to weighting the individual field appreciation factors by total recoverable reserves. In a few instances, the last observation year occurs before 1996. To preserve continuity such a field's reserves could be subtracted from the denominator of the appreciation factor in the years following cessation of production. However, the appreciation profile would be biased if the appreciation experience of those fields left in were not representative. To guard against any such bias, this approach is not employed. Instead, the factors are confined to appreciation for those fields of a given vintage still on production in 1996.

The different patterns of appreciation by vintage are illustrated in Figs. 5 and 6. The annual plots are aggregates for those fields with a common history of 10 years or more. Their appreciation profiles are quite disparate and not smooth.[29]

Table 6 shows 1996 appreciation factors by vintage in the two country sectors. In the UK, the 1975, 1976 and 1977 vintages have factors for the last observation year in roughly the same bracket. But the 1978 to 1987 vintages show marked fluctuations, many reflecting the small number of fields in a given vintage. For example, the strong appreciation factor in the 1979 vintage of 2.44 simply represents the experience of one field—Cormorant. The high factor of 2.39 in 1985 reflects the performance of three fields (Highlands, Innes and Scapa).

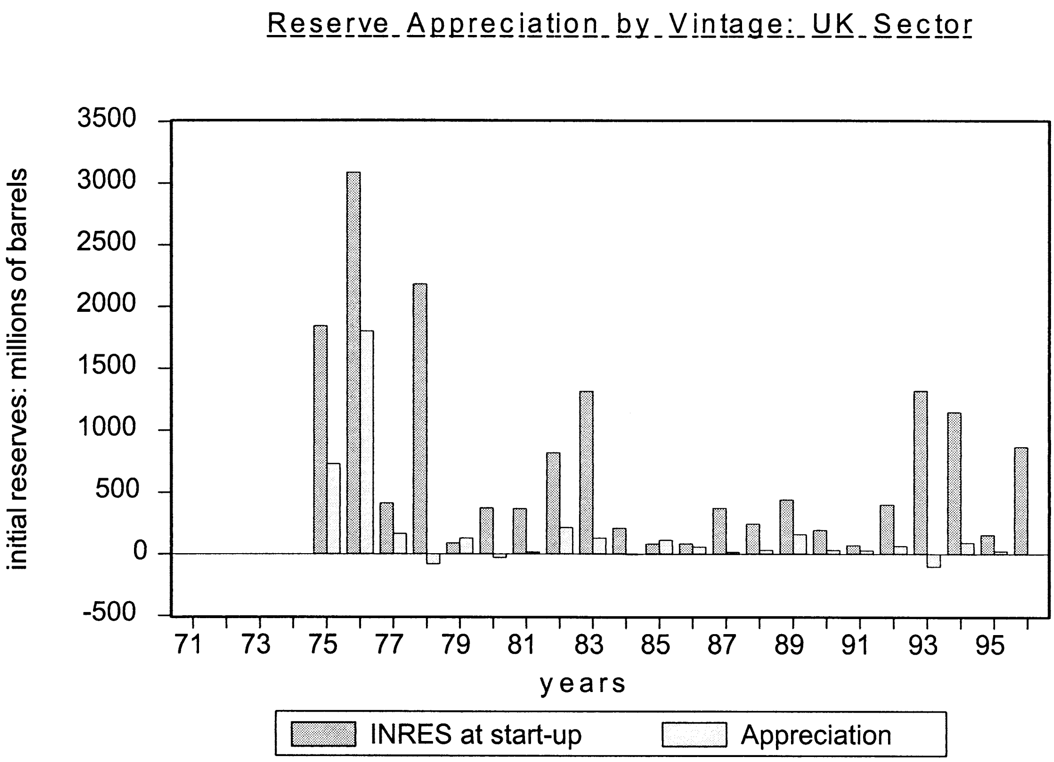

Fig. 5. Reserve appreciation by Vintage: UK sector.

For vintages after 1987, appreciation, while relatively modest, falls within a somewhat tighter range.

The picture in Norway is also erratic, at least until the mid 1980s. Strong appreciation is recorded for the 1971 vintage, but this is just for one field—Ekofisk. The same comment applies to the 3.5 appreciation factor for 1982: it is just for Valhall. However, a much tighter range holds for 1986 and beyond. Indeed, the factors for the 1988, 1990 and 1992 vintages are pretty much the same at about 1.3. This in part reflects the more circumscribed scope for appreciation over the shorter interval.

Generally, for both sectors there is no obvious tendency for early fields to grow more than later fields, nor vice-versa, over comparable production periods.

4.5. Reserve appreciation by field size

A threefold classification was employed: small (reserves less than 100 million barrels); medium (greater than 100 million barrels, less that 400 million barrels); and large (greater than 400 million barrels).[30] The measurement uses total recoverable reserves at production start-up.

For the UK, mean field sizes in the respective divisions are 42 mmbbls, 215 mmbbls and 819 mmbbls—supporting the adopted classification. The number of fields in each category

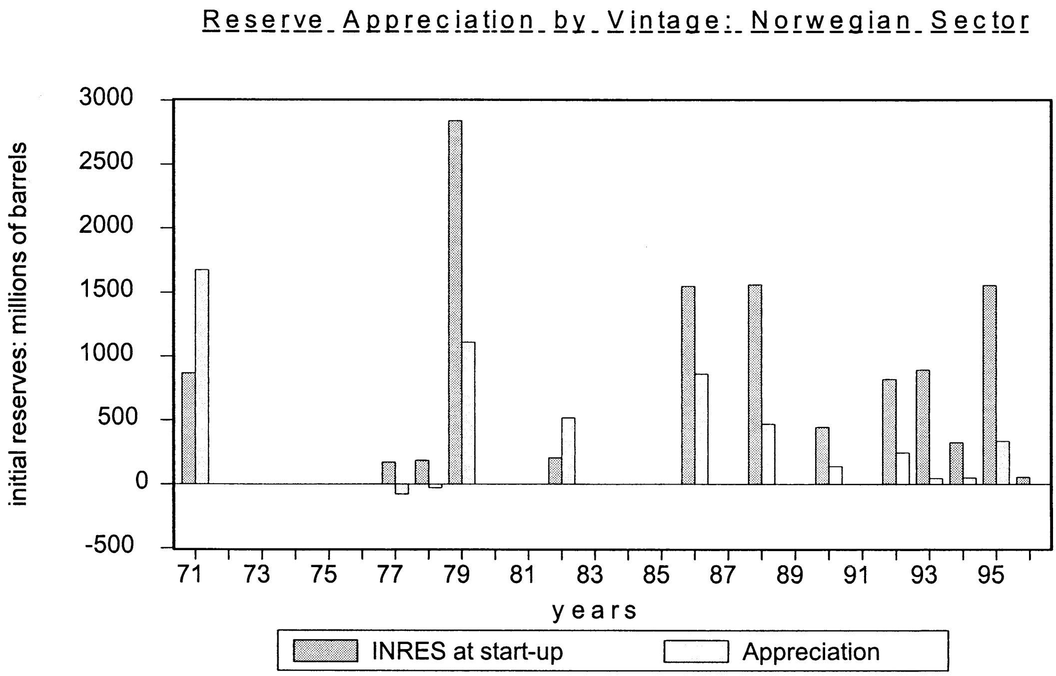

Fig. 6. Reserve appreciation by Vintage: Norwegian sector.

was 46 small, 22 medium, and 12 large (16 fields with 1996 start-up were eliminated). Appreciation profiles were calculated by category for those fields with at least ten years of production. The number of fields so qualifying was 11 small, 12 medium and 10 large. The greatest degree of appreciation was displayed by the small group, with a factor of 1.8, ten years after start-up. The medium category declined to 0.9 after ten years; the large category increased to 1.2 after 14 years.

For Norway, the number of fields in the small, medium and large categories were nine, 11, and nine, respectively (one field with 1996 production start-up was dropped). Fields with at least 10 years of production history were three small, five medium and three large. The greatest degree of appreciation was displayed by the medium group, with a factor of 1.4, eleven years after production start-up. The small and large categories showed similar factor increases after eleven years of 1.16 and 1.19 respectively.

4.6. Reserve appreciation by water depth

In terms of water depth, the fields can be classified as relatively shallow (less than 100 meters), medium (more than 100 meters, less than 149 meters) and deep (more than 150 meters).

The respective number of fields in each category for the UK is 28, 48 and 12 (recall that data were not available for eight of the 96 UK fields). For fields with at least ten years of production history, the shallow category had the highest appreciation factor by the tenth year of history; the deep category shows virtually none.

Table 6
Reserve appreciation factors by vintage

Year of start-up	UK sector Number of fields	Appreciation factor 1996	Norwegian sector Number of fields	Appreciation factor 1996
1971	0		1	2.93
1972	0		0	
1973	0		0	
1974	0		0	
1975	2	1.39	0	
1976	5	1.58	0	
1977	1	1.40	2	0.55
1978	4	0.96	1	0.86
1979	1	2.44	4	1.39
1980	1	0.92	0	
1981	3	1.04	0	
1982	2	1.26	1	3.50
1983	5	1.10	0	
1984	2	0.98	0	
1985	3	2.39	0	
1986	2	1.67	3	1.56
1987	3	1.04	0	
1988	2	1.13	2	1.30
1989	8	1.40	0	
1990	5	1.17	3	1.31
1991	1	1.40	0	
1992	8	1.16	2	1.30
Total	58		19	

Note: 1993, 1994, 1995, 1996 omitted (insufficient history). Fields included are those with more than four years of production history; fields abandoned before 1996 are excluded.

For Norway, the three depth categories breakdown as: shallow, 15 fields; medium, six; and deep, nine. For fields with ten years or more of consistent history, the appreciation factor by the tenth year was highest for the deep category at 1.46 (but that was just one field, Gullfaks); the medium category recorded minimal appreciation. These results contrast with those for the UK.

4.7. Reserve appreciation by gravity

Fields by gravity can be broadly classified as heavy (less than 30 degrees API), medium (30 to 39 degrees), and light (40 degrees and over).

In the UK, about 80% of the reserves (62 fields) are medium and some 13% are light (20 fields). Only four fields are classified as heavy. Recall that gravity information was not available for 10 UK fields. Since the appreciation experience of the heavy fields is minimal, comparisons of appreciation factors were restricted to medium and light groupings.

The UK results were plain: there is a much greater propensity for lighter gravity reserves to appreciate compared with medium gravity. The appreciation factor for light is about 1.4 in the last common observation year; for medium it is only modestly above unity. This difference is not attributable to lighter gravity fields having a longer production history than the medium gravity fields; it is only marginally higher at one year.

For Norway, 11 fields were classified as light, 16 as medium and two as heavy (information was not available on two of the 30 Norwegian fields). The ranking of appreciation factors after 10 years of production history was heavy, 1.46 (one field, Gullfaks); medium, 1.23; and light, 1.10.

4.8. Reserve appreciation by depletion rate

A simple two-fold division was employed for the reserves-production ratio (RPR): those fields of less than 7 years; and those of seven or more. Fields with apparent RPRs of less than one year or apparent RPRs exceeding 50 were excluded on the grounds of suspect data. The resulting number of UK fields in the rapid depletion category was 45, accounting for 66% of 1996 initial reserves for the 69 fields. The slower depletion category totalled 24, comprising 34% of initial reserves. In Norway, seven fields were in the rapid depletion category, accounting for 68.5% of 1996 initial reserves; four fields were in the slower depletion category.

Appreciation profiles for the two categories for the UK show that by the tenth year the appreciation factor for the rapid category exceeds that for the slower one, but the difference is modest (1.12 vs. 1.09). For Norway, the eleventh year appreciation factor for the more rapid category was 1.25; for the slow it was 1.2, but increased markedly to 1.6 by year 15 of production.

4.9. Reserve appreciation by geological age

As noted in Section 2, in the UK fields of the Jurassic age predominate. The sparse number of fields straddling more than one geological age with 10 years of history necessitated including them with the “other” category, totalling 27 fields. The tertiary accounted for 12 fields.

The Jurassic category had only marginal appreciation by the tenth year, while the ‘other’ category had a corresponding appreciation factor of about 1.4. Appreciation in the Tertiary group over the ten year period was modest at 1.1. Recall that the average UK appreciation factor defined by dividing initial reserves in the last observation year by initial reserves at start-up is 1.22 (see Table 3). The implication is that some Jurassic fields with a history of under 10 years had quite strong appreciation, and/or that some Jurassic fields had noticeable appreciation beyond ten years.

Norwegian data afforded a distinction between chalk (9) and sandstone (21) fields. Most fields in southern Norway, generally the Ekofisk area, are located in Cretaceous chalk formations. Later, when the chalk formation subsides, reservoir pressure tends to rise—which might augment reserves.[31] This kind of effect is partly revealed by the data. Seven fields of the chalk category provided 15 years of consistent history, with an appreciation factor by year 15 of 1.43. But the appreciation factor in year 11 for these chalk fields was only 1.09; reserve additions from year 11 to 15 were very considerable. Five Sandstone fields showing 11 years of consistent history yielded an appreciation factor by year 11 of 1.29.

Table 7
Appreciation factor summary: UK sector

	Number of fields	Appreciation factor last observation year	Appreciation factor range last obs year	Average years on production
All fields[a]	80	1.23	0.08–2.92	9.3
Depth[b]				
Shallow	20	1.17	0.68–2.42	8.1
Medium	41	1.27	0.42–2.92	9.8
Deep	11	1.15	0.38–1.76	12.0
Gravity[c]				
Heavy	2	1.01	1.00–1.04	3.5
Medium	56	1.26	0.42–2.92	10.7
Light	14	1.14	0.38–2.42	6.4
Depletion rate				
High	45	1.19	0.42–2.67	9.0
Low	24	1.34	0.38–2.92	10.6
Geological age				
Jurassic	39	1.13	0.38–2.44	10.9
Tertiary	10	1.26	0.64–1.50	8.3
Triassic/Jur/Tertiary	9	1.83	0.68–2.92	7.1
Other	22	1.37	0.08–2.62	7.8
Size				
Small	46	1.40	0.08–2.62	6.9
Medium	22	0.99	0.53–1.76	11.3
Large	12	1.32	0.73–2.92	16.9

[a] 16 Fields with 1996 start-up eliminated.
[b] Missing data on 8 fields.
[c] Missing data on 10 fields.

4.10. Summary features

The preceding discussion was mainly directed at appreciation profiles for groups of fields with the same number of years on production. Table 7 and Table 8 for the UK and Norwegian sectors provide aggregate appreciation factors by category within the various classifications, calculated as the sum of recoverable reserves in the last observation year divided by the corresponding sum at production start-up. Of course, comparisons across categories are affected by the average number of years on production: simple averages are shown in the last columns.

The results are varied. Average differences among categories within a classification are generally material. However, within a given classification the appreciation experience of fields comprising a category is by no means similar. The ranges in appreciation factors shown in both Tables 7 and 8 are wide. This suggests that division by categories does not appreciably compress the disparate experience of individual fields. Formal testing of mean appreciation factors among categories for a given classification was not pursued, but the wide ranges suggest detection of statistically significant differences may be elusive.

From Table 7, ostensibly the greatest chance for a UK field to show high appreciation

Table 8
Appreciation factor summary: Norwegian sector

	Number of fields	Appreciation factor last observation year	Appreciation factor range last obs year	Average years on production
All fields[a]	29	1.46	0.37–3.50	9.7
Depth				
Shallow	14	1.85	0.37–3.50	13.9
Medium	6	1.41	0.44–2.13	7.8
Deep	9	1.3	1.00–1.54	4.3
Gravity				
Heavy	2	1.43	1.32–1.46	6.5
Medium	15	1.55	0.44–3.50	8.5
Light	12	1.35	0.37–2.17	11.6
Depletion Rate[b]				
High	18	1.40	0.37–2.13	8.5
Low	9	1.63	0.86–3.50	10.9
Geological age				
Chalk	9	1.91	0.44–2.13	16.7
Sand	20	1.36	0.37–3.50	6.5
Size				
Small	9	1.01	0.44–2.17	8.4
Medium	11	1.39	0.37–3.50	9.9
Large	9	1.50	0.98–2.93	10.6

[a] 1 Field with 1996 start-up eliminated.
[b] Missing data on 2 fields.

would be for it to be of medium depth and gravity, produce at a low rate, be small, and straddle more than one geological age. For Norway, from Table 8 the most favorable combination would appear to be a large, shallow field of medium gravity, with a slow output rate, residing in a chalk formation—a somewhat different mix of "ingredients" than for the UK. However, such field characteristics are likely not well correlated.[32]

5. Reserve appreciation functions

The preceding section looked at the reserve information classified initially by field and then by broad categories such as field vintage, size, water depth, gravity, depletion rate, and geological age. This section searches for statistical regularity in the reserve appreciation trajectories by fitting equations. Fields seldom shrink in size, so a monotone restriction model might be reasonably used to depict reserve growth.[33]

5.1. Similar analysis

There is some precedence in the analysis of Canadian reserve data. In Alberta, a function has been adopted of the form:

$$AF_t = 1 + k(1 - e^{-bt}) \tag{4}$$

where

AF_t = appreciation factor, year t
k = (positive) scale constant
t = time elapsed from year of discovery, $t = 0,1, \ldots.$
b = fitted constant.

Variations in appreciation patterns by reservoir groups were expressed by differences in the fitted constant, b [see OGCB (1969)].[34] Note that if b is positive the derivative of AF_t with respect to t is positive ($\partial AF_t/\partial t = bke^{-bt}$); and the second derivative, $\partial Af_t^2/\partial^2 t = -b^2ke^{-bt}$, is negative. That is, the function is concave from above, growing at a declining rate. Its upper asymptote is $1 + k$.

The notion of an upper asymptote is partly suggested by the fact that the recovery factor component of reserves cannot exceed unity. And while limitations on oil-in-place are less obvious, nevertheless perpetual growth is inconsistent with inherent geological constraints on field contours. This is congruent with Adelman's observation that for a group of fields, reserves added will increase at a decreasing rate, and finally converge to a limiting value.[35]

Analysis of reserve appreciation in the US has been undertaken by Attanasi and Root (1994). Growth functions were estimated in relation to the year of field discovery, calculated both on an unconstrained basis, and after incorporating a restriction that the annual percentage growth declines as a field ages. The restricted function is analogous to the Alberta Eq. (4).

5.2. Field analysis

My focus was on those fields exhibiting some degree of reserve growth over at least a 10 year interval. Profiles for individual fields [Watkins (2000, Charts C-1 and C-2)] suggested 27 fields in the UK satisfied that criterion with sufficient degrees of freedom to allow estimation, nine in the Norwegian sector.

Two functional forms were fitted to the profiles of appreciation factors. The first was parabolic, with an intercept of one. The restriction on the intercept simply allows the appreciation factor to start as a ratio of unity. The equation is:

$$AF_t = 1 + c_1t + c_2t^2 \tag{5}$$

where $t =$ time elapsed after production start-up, $t = 0,1,2 \ldots.$

The second equation is given by Eq. (4), imposing a declining slope if the sign of the coefficient b were positive. But the appreciation function is measured from the years after production start-up, rather than from the years after discovery given by (4).

5.3. Field parabolic functions

The results of estimating Eq. (5) are summarized in Table 9. Not surprisingly, the initial results were infected with first order autocorrelation. The coefficient estimates listed in the

Table 9
Reserve appreciation profiles by field: parabolic curve fits

Field	Name	No. obs	Adj R	DW	C(1)T	C(2)T^2	AR(1)
UK sector							
5	Arbroath	6	0.84	2.48	0.077**	−0.0035	−0.50
6	Argyll	17	0.96	1.49	0.006	0.0016	0.77***
8	Auk	20	0.87	1.86	0.033*	0.0013	0.39*
9	Balmoral	10	0.77	1.87	0.083**	−0.0029	0.39
11	Beatrice	15	0.80	1.64	0.035***	−0.00063	0.46
13	Beryl A&B	20	0.86	1.58	0.017	0.0041	0.60***
19	Brent	20	0.94	2.02	−0.0074***	0.00094***	−0.095
22	Buchan	14	0.96	1.92	0.13***	−0.0023*	0.33
24	Claymore	19	0.92	1.42	0.012	0.00057	0.81***
27	Cormorant south	17	−3.44[a]	1.29	0.25***	−0.01*	0.70***
36	Dunlin	18	0.93	1.78	0.0042	0.00089*	0.58**
38	Eider	8	0.91	2.11	0.024*	0.003	−0.25
42	Forties	21	0.93	1.91	0.024**	−0.00022	0.76***
43	Fulmar	14	0.83	2.04	0.023	0.00026	0.62**
45	Gannet C	4	0.95	1.59	−0.049	0.027	−0.32
46	Gannet D	4	0.98	1.57	−0.072*	0.049**	−1.96*
53	Highlander	11	0.73	1.12	0.28***	−0.016**	0.43
57	Innes	5	0.98	1.04	0.87***	−0.11***	−0.94
58	Ivanhoe	7	−11.58[a]	0.88	0.27	−0.03	0.29
66	Magnus	13	0.84	1.82	0.056***	−0.0016	0.30
68	Maureen	13	0.82	1.19	0.069***	−0.0032**	0.51*
78	Osprey	5	−63.18[a]	1.18	0.26*	−0.039	0.029
80	Petronella	10	0.84	0.72	0.18	−0.0023	0.65*
81	Piper	20	0.95	1.52	0.048***	−0.00086	0.79***
82	Rob Roy	7	0.81	1.76	0.02	0.012	0.09
84	Scapa	11	0.84	1.62	0.21***	−0.0047	0.31
92	Tern	7	0.83	0.77	0.09	0.0053	0.20
Norwegian sector							
101	Gullfaks		0.92	1.73	−0.0047	0.0054***	0.16
104	Heimdal		0.68	1.75	0.26***	−0.015**	0.27
105	Hod		0.96	1.82	0.41***	−0.033***	−0.90*
108	Oseberg		0.76	1.40	0.009	0.0045	0.48
112	Statfjord unit		0.93	1.76	−0.0046	0.0026***	0.36
116	Ula		0.80	1.30	0.33***	−0.027***	0.18
117	Valhall		0.93	1.62	−0.054	0.019***	0.091
118	Veslefrikk		0.83	1.45	0.10*	−0.00077	−0.30
126	Ekofisk		0.98	1.96	−0.0038	0.0034***	0.30

* = significant at 10% level; ** = significant at 5% level; *** = significant at 1% level.

Equation: $\boxed{AF_t = 1 + C(1)T + C(2)T^2 + AR(1)}$

(coefficients adjusted for first-order autocorrelation)

where: AF_t = appreciation factor, year t
T = time since production start-up, T = (0, 1, . . .)
AR(1) = first order autocorrelation coefficient

[a] Arises within Eviews from imposition of intercept of one.

table are after adjustment for first order autocorrelation, but not for higher orders.[36] And some equations still contain first order autocorrelation, an indication of omitted variables.

In the UK sector, the degree of fit is reasonable, although for three fields (#27, #58, #78) the adjusted R^2 was not defined.[37] The "linear" coefficient, c_1 attaching to time was statistically significant and positive in the majority of cases (17 out of 27); of the remaining 10 fields, three were negative (one significantly so). But the curvature coefficient, c_2, was only significant for eight fields. Here the sign was positive for three fields; in two fields the curvature coefficient arrested a decline, in the other the coefficient accelerated an upward tilt. In all the five fields where the curvature coefficient was significant and negative, it diminished an upward tilt.

All nine Norwegian fields listed in Table 9 showed a reasonable degree of fit, but also evidence of first order autocorrelation. For the majority, this was eliminated. Four fields had significant linear coefficients; all but two had significant curvature coefficients. There was a consistent asymmetry for those fields with significant curvature coefficients: when the tilt in appreciation factors was upward, the curvature term diminished it; when the tilt was downward, it was arrested.

5.4. Field constrained functions

Eq. (5) was estimated, with the time counter defined as years after start-up. All fields displayed an upward slope (the “b” coefficient was positive). Of the 28 UK fields, only seven had statistically significant coefficients and showed a distinctive declining upward slope.[38] All the rest displayed virtually linear upward tilts, with nary an upper asymptote in sight. In these latter cases, the estimated “b” coefficient in Eq. (4) is small relative to time(t); hence the denominator of the first derivative tends towards unity, while the scale coefficient ‘k’ relative to b is sizeable, yielding a nontrivial numerator. When “‘b” is small it is readily seen that the second derivative is small as well.

Of the ten Norwegian fields to which the constrained function was fitted, three had a statistically significant declining slope.[39] The remaining seven fields had close to linear upward slopes: an approach to the upper asymptote is remote. The statistical results for the constrained functions are not included in Table 9.[40]

5.5. Summary comment

The conclusion from these curve fitting exercises is that thus far “diminishing returns” for the appreciation factor in the majority of fields examined in both sectors are not readily visible. The constrained function affords little further insight from that revealed by the simple parabolic function.

The appreciation functions could be extrapolated to estimate further reserve appreciation. Any such exercise implicitly assumes that technological improvement and changes in economic conditions during the observation period that have affected the function will continue.

6. Analysis of oil-in-place and recovery factors

Confidential information on oil-in-place was obtained from operators of about one third the UK fields. For Norway, the NPD provided data for all but one Norwegian field. To avoid

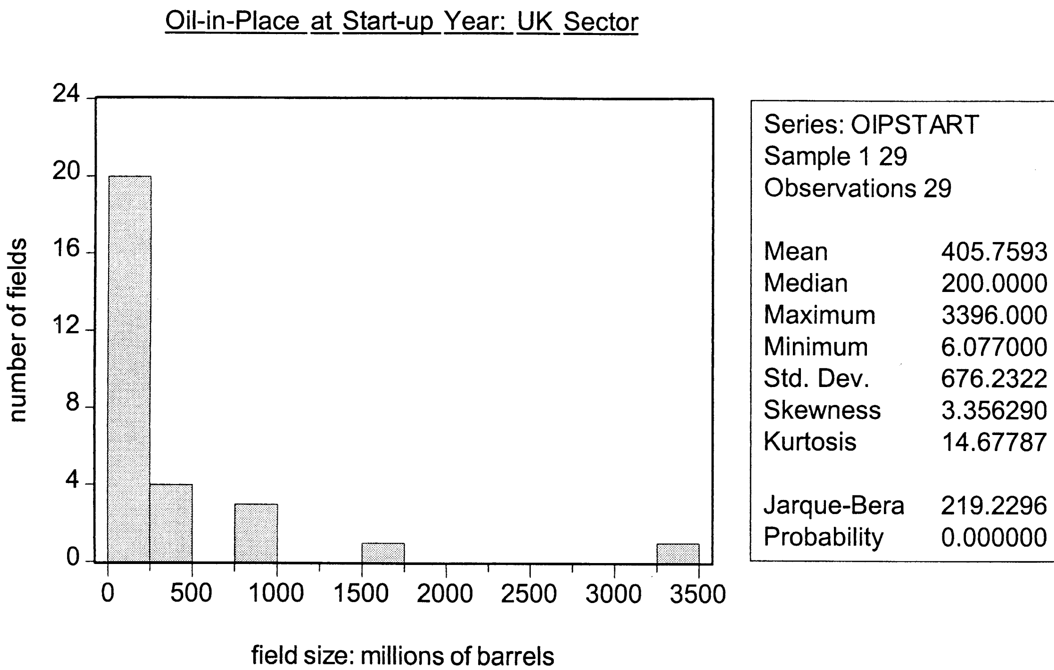

Fig. 7. Oil-in-place at start-up year: UK sector.

disclosure of individual field data, the analysis is confined to groups of at least two fields. Figs. 7 and 8 show histograms of oil-in-place at production start-up for the UK and Norway respectively.

6.1. UK

The UK sample is limited and does contain some unresolved anomalies. *Thus the UK results should be treated with caution.*

Summary statistics are provided in Table 10. Average field volumes of oil-in-place grow by some 11% between start-up and the last observation year. Average recoverable reserves for the 29 fields at start-up were about 183 million barrels (15 million barrels higher than the mean for all 96 fields—see Table 1). The implied mean recovery factor at start-up is 44%, rising to around 47% in the last observation year.

The distribution of field oil-in-place is positively skewed: the hypothesis of lognormality would not be rejected. This is not surprising. Oil-in-place represents the distribution of reserves in nature, a distribution seemingly inherently positively skewed, although it does not follow that of the family of skewed distributions, the lognormal provides the best fit [see Smith & Ward (1981)].

The information in Tables 10 and 11, and corresponding data for recoverable reserves for the 29 field data set can be combined to breakdown reserve appreciation between that attributable to changes in oil-in-place and that attributable to changes in the recovery factor. If the mean field initial recoverable reserve at production start-up only grew by virtue of the

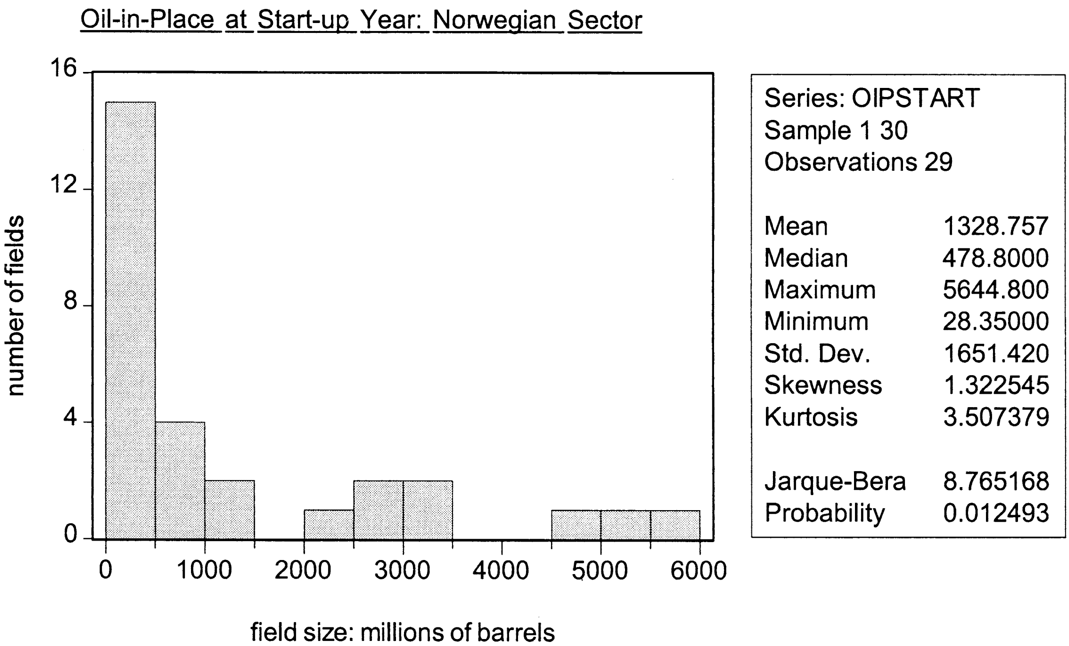

Fig. 8. Oil-in-place at start-up year: Norwegian sector.

11% change in oil-in-place, the mean reserve in the last observation year would have been 203 million barrels, an increase of 20 million barrels. Actual reserve growth for the average of the 29 fields was 28 million barrels. Thus 8 million barrels of the increase is attributable to changes in the recovery factor:

total change in average field recoverable reserves = 28 mmbbls

change attributable to oil-in-place = 20 mmbbls

change attributable to recovery factor = 8 mmbbls.

Table 10
North Sea oil-in-place: summary statistics

Sector	At production start-up (1) Number of fields	(2) Mean mbbls	(3) Std. dev mbbls	(4) Coeffic of variation (3)/(2)
UK	29	406	676	1.67
Norway	29	1,219	1,530	1.26
	In last observation year[a]			
UK	29	451	734	1.63
Norway	29	1,377	1,713	1.24

[a] 1996 or year when field is shut in.

Table 11
North Sea oil-in-place appreciation: summary statistics[a]

Sector	(1) Number of fields	(2) Mean mmbbls	(3) Std. dev mmbbls	(4) Coeffic of variation	(5) Appr factor
UK	29	45	101	2.23	1.11
Norway	29	158	344	2.18	1.13

[a] Appreciation calculated as difference between oil-in-place at start-up and oil-in-place in the last production year.

In the UK field sample, then, about 70% of reserve appreciation over the period considered related to oil-in-place, 30% to the recovery factor. Thus, if the field sample for which oil-in-place data were representative, *it is extensions in field contours and revisions to in-place field properties that account for the great majority of reserve appreciation in the UK sector, not improvements in the estimated proportion of oil to be recovered.* But I repeat my earlier caution that the results are sample sensitive.[41] And they partly reflect that fact that at start-up estimated recovery factors in the UK are already at high levels, the result of early inception of ER schemes, primarily water injection.[42] This practice was encouraged by UK tax provisions that offered tax relief for early investment, compared with later expenditures.[43]

6.2. Norway

The summary statistics in Table 10 show aggregate Norwegian oil-in-place volumes growing by some 13% between start-up and the last observation year. If the oil-in-place data were related to those for recoverable reserves for the 29 fields, the implied mean recovery factor is 32% at start up, rising to 42% by the last observation year—an appreciable growth of about 30%, or about 10 percentage points. But the average recovery factor in the last observation year remains below that at start-up in the UK sample.

The size distribution of oil-in-place has noticeable positive skewness. As for the UK sector, the hypothesis of lognormality would not be rejected.

Mean field initial recoverable reserve at production start-up for the 29 Norwegian fields is 390 million barrels. If the average recovery factor at start-up of 32% were fixed, mean recoverable reserves by the last observation year would have grown by some 13% by virtue of growth in oil-in-place, reaching 440 million barrels, an increase of 50 million barrels.

Mean recoverable reserves for the 29 fields grew by 188 million barrels by the last observation year. Hence, 138 million barrels of this increase is attributable to changes in the recovery factor:

total change in average field recoverable reserves = 188 mmbbls

change attributable to oil-in-place = 50 mmbbls

change attributable to recovery factor = 138 mmbbls.

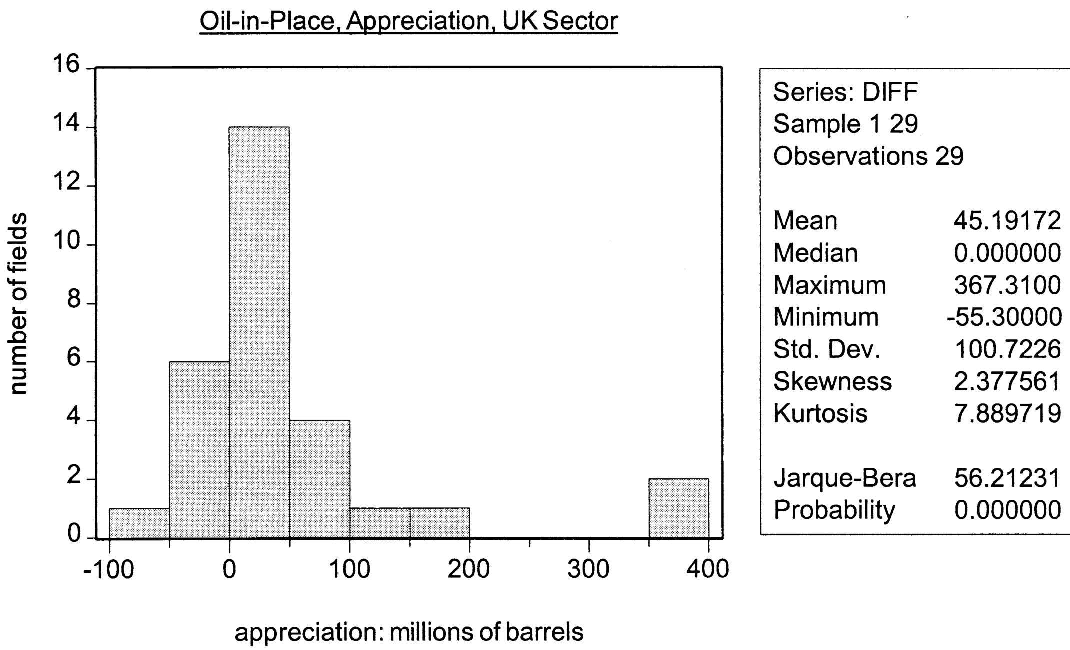

Fig. 9. Oil-in-place, appreciation, UK sector.

In Norway, then, about 25% of reserve appreciation over the period considered related to oil-in-place, 75% to the recovery factor. *Thus, the strongest influence by far on reserve appreciation in the Norwegian sector comes from improvements in the recovery factor, not from field extensions and reassessment of in-place field properties.* This contrasts with the UK results.

Figs. 9 (UK) and 10 (Norway) are histograms of oil-in-place appreciation. Table 11 shows summary statistics for the increments in oil-in-place for both sectors. Again the shape of the distribution is heavily skewed—lognormality would not be rejected. Average field oil-in-place appreciation in Norway exceeds that in the UK sample by a multiple of 3.5 (recall that for initial reserves the corresponding multiple is close to 5).

I now turn to oil-in-place appreciation and changes in recovery factors between start-up and the last observation year. The examination is for the various classifications identified earlier in looking at initial recoverable reserves. It does lump together fields of different ages; some of the variation among categories reflects different time intervals.

6.3. UK oil-in-place appreciation and recovery factors

Table 12 shows oil-in-place appreciation factors in the last observation year and changes in recovery factors between start-up and the last observation year, for the various categories within classifications. Differences in appreciation among categories for a given characteristic

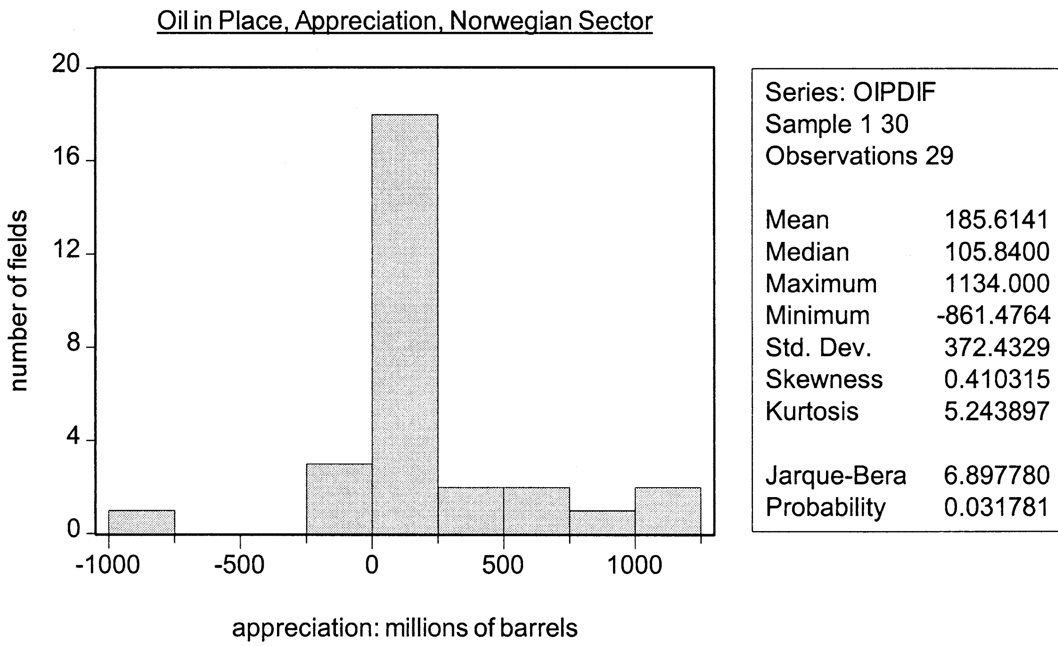

Fig. 10. Oil-in-place, appreciation, Norwegian sector.

are quite marked, with the exception of gravity. However, the range in factors within each category is generally wide. Fields that are shallow, small, produce at low rates and are not of the Jurassic age record the highest appreciation.

Noticeable differences in recovery factors among categories are also revealed. Highest average recovery factors in the last observation year were recorded by large, medium depth Jurassic fields. In absolute terms, the shifts in recovery factors were minor, except for certain light gravity, medium sized fields.

6.4. Norwegian oil-in-place appreciation and recovery factors

Table 13 shows oil-in-place appreciation factors reached by the last observation year for the various categories, as well as changes in implied recovery factors. The relatively modest shift in average oil-in-place appreciation of 13% tends to limit the scope for differences among categories within a given classification. However, the greater propensity for deep heavy gravity fields of medium size and fields in the sandstone formation to exhibit oil-in-place appreciation is noticeable. Similarly to the UK, the range in appreciation factors for categories within a classification is large.

Levels of recovery factors also show substantial variation among categories within a classification. Shallow, medium gravity fields with low depletion rates and located in chalk formations have relatively low recovery factors, at least at start-up. This may well reflect inherent physical reservoir properties. The ranking of recovery factors by category is sustained in the last observation year, except for the size classification.

Table 12
Summary: UK sector, oil-in-place and recovery factors

	Number of fields	OIP apprec. factor last obs. year	Apprec. factor range	Recovery factor at start-up	Recovery factor at last obs year	Change in recovery factor	Average years on production
All fields	29	1.11	0.77–2.04	0.44	0.47	0	9.0
Water Depth							
Shallow	15	1.19	0.82–2.04	0.44	0.45	0.01	7.9
Medium	10	1.07	0.77–1.65	0.50	0.50	0	10.6
Deep	4	1.12	1.00–1.70	0.37	0.44	0.07	9.5
Gravity							
Heavy	0	—	—	—	—	—	—
Medium	24	1.11	0.77–2.04	0.44	0.45	0.01	9.3
Light	5	1.08	0.82–1.65	0.56	0.66	0.10	8.0
Depletion Rate							
High	19	1.14	0.82–2.04	0.50	0.50	0	9.5
Low	10	1.20	0.77–2.04	0.38	0.42	0.04	8.3
Geological Age							
Jurassic	23	1.07	0.77–2.04	0.47	0.50	0.03	9.0
Tertiary	0	—	—	—	—	—	—
Tri/Jur/Tert	6	1.48	0.98–2.04	0.32	0.29	−0.03	9.1
Other	0	—	—	—	—	—	—
Size							
Small	19	1.23	0.77–2.04	0.31	0.32	0.01	6.7
Medium	6	1.15	0.93–1.43	0.56	0.48	−0.08	11.7
Large	4	1.05	0.97–1.11	0.49	0.54	0.05	13.8

Some marked differences are shown by changes in recovery factors. Deep fields record only a modest variation, in contrast to shallow and medium fields. The ranking of shifts in recovery factors by field size accords with intuition: large fields showed the greatest, followed by medium and small (small actually suffering a reduction). This might result from the greater scope for profitable introduction of ER schemes the larger the accumulation. In contrast, the changes in recovery factors between chalk and sandstone formations are much the same—and differences by gravity, at least between medium and light, are minor. Changes in average recovery factors for rapidly and slowly depleting fields are the same.

6.5. Validity of comparisons

This breakdown of the oil-in-place and recovery factor elements of reserve appreciation reveals marked contrasts between the UK and Norwegian experience. Assuming the differences are valid (recall the UK results relate to a sample of one third of the field population, Norway's to all but one field), one issue is whether this outcome is influenced by reserve reporting practices.

In Section I of this paper I referred to the fact that reserve definitions vary across jurisdictions, and the UK and Norway are no exception. It could be, then, that higher recovery factors in the UK represented more generous attribution, allied to tight standards for

Table 13
Summary: Norway, oil-in-place and recovery factors

	Number of fields	OIP apprec. factor last obs. year	Apprec. factor range	Recovery factor at start-up	Recovery factor at last obs. year	Change in recovery factor	Average years on production
All fields	29	1.13	0.34–1.82	0.32	0.42	0.10	9.7
Water depth							
Shallow	15	1.07	0.34–1.82	0.18	0.33	0.15	13.9
Medium	5	1.12	0.87–1.25	0.46	0.58	0.12	7.8
Deep	9	1.20	0.84–1.47	0.37	0.40	0.03	4.3
Gravity							
Heavy	2	1.23	1.19–1.32	0.39	0.45	0.06	6.5
Medium	15	1.14	0.80–1.58	0.28	0.38	0.10	8.5
Light	11	1.05	0.34–1.82	0.39	0.50	0.11	11.6
Depletion rate[a]							
High	18	1.14	0.82–1.79	0.42	0.52	0.10	8.5
Low	9	1.13	0.58–1.82	0.23	0.33	0.10	10.9
Geological formation							
Chalk	9	1.08	0.34–1.82	0.17	0.32	0.15	16.7
Sand	20	1.15	0.82–1.79	0.34	0.47	0.13	6.5
Size							
Small	9	1.08	0.34–1.82	0.30	0.27	−0.03	8.4
Medium	11	1.19	0.82–1.58	0.30	0.38	0.08	9.9
Large	9	1.12	0.80–1.47	0.33	0.44	0.11	10.6

[a] Missing data on two fields.

oil-in-place. If so, that would contribute to the strong role of oil-in-place in appreciation of UK reserves.

In Norway, generosity in reserve reporting may have veered in the direction of oil-in-place.[44] At the same time, justification for recovery factors might have relied heavily on production performance over time.

Definitive information to resolve this issue is not readily at hand. But it is probable that some of the differences in appreciation patterns between the UK and Norway are accounted for by variations in reserve reporting standards, differences that would disappear with application of uniform methods. Some, maybe, but likely not all.

7. Conclusions

The size distribution of recoverable oil reserves for oil fields in the North Sea basin has much in common with that elsewhere. It is heavily skewed, with a predominance of smaller fields. The hypothesis of lognormality would not be rejected. The average field size in the UK is less than half that for Norway. In both sectors, a minority of fields account for the majority of aggregate reserves.

Reserve appreciation between production start-up and the last observation year (usually

1996) for the average field in the UK was about 20%. For Norway it was close to 50%, over an average production period much the same as for the UK. This difference is marked. And given their larger average size, average appreciation of Norwegian fields approached five times that in the UK. In both sectors, reserves appreciation by field is even more highly concentrated than that for field recoverable reserves.

Total reserve appreciation in the combined sectors from start-up to 1996 is about nine billion barrels. The magnitude of this growth is equivalent to the current remaining proved reserves of a country such as Algeria. Certainly, the view that appreciation of offshore resources would be minimal is contradicted by these numbers.

More light on the contrast between appreciation of Norwegian and UK fields is shed by attempting to break down estimates of recoverable reserves into the two components of oil-in-place and the recovery factor, the proportion of oil-in-place expected to be recovered before shut-down. About 75% of appreciation recorded by Norwegian fields was accounted for by increases in the recovery factor, a factor averaging some to 32% at start-up, 42% in the last observation year, a 10 percentage point increase. The rest represented appreciation of oil-in-place of some 13%, on average. The UK experience was quite different. For the field sample used, the great majority of the (lower) appreciation was accounted for by increases of oil-in-place of 11%; the increase in the recovery factor was some three percentage points between start-up and its value in the last observation year of 47%.

However, these UK results are based on information from only about one third of the 96 fields, Norway's on 29 out of 30. The UK oil-in-place analysis, then, must be regarded cautiously. Moreover, comparisons between the two countries may be bedevilled by differences in reserve reporting standards. Nevertheless, such a marked difference in appreciation experience may well not vanish even if data were available for all UK fields.

Apart from inherent variations in the physical nature of the fields, much of the difference in reserve appreciation characteristics between the two sectors has to do with the higher average recovery factors at production start-up in the UK. UK field development relied on early inception of ER schemes to a greater extent than seems to have occurred in Norway. Indeed, by 1996 average recovery factors in Norway still had not caught up with those in the UK.

The majority of fields in both sectors are of younger age, but there is a predominance of reserves in older fields, an indication of larger accumulations being found earlier, a common occurrence. Few fields are of heavy gravity; the medium category is predominant. Average field water depths are not appreciably different between the two sectors. Most UK fields are of the Jurassic age, while in Norway most are in sandstone rocks of varying ages. Average (reserve weighted) rates of depletion are faster in Norway, but median rates in the two sectors are much the same.

Although, as would be expected, appreciation functions normally trend upward over time, appreciation profiles by field show a great variety: there is no typical trajectory. It might be thought that once reserves were sorted in terms of characteristics such as vintage, water depth, gravity, size and geological age and then grouped within these classifications, fields sharing a common category might display more congruent appreciation profiles. Such does not appear to be the case. Individual fields within a given category still showed considerable disparities in appreciation behavior. However, average differences among categories for some characteristics were revealed.

Ostensibly, in the UK sector the highest recoverable reserve appreciation might be shown by small fields of medium depth and gravity producing at a low rate, and straddling several geological ages. In Norway, they would be shallow, large, of medium gravity, with a slow rate of production, and located in a chalk formation. But these inferences would be facile: field properties do not conform to this mix of attributes. And the comparisons lack adjustment for differences in aggregate production lives among categories.

No clear evidence emerges thus far that North Sea oil reserve appreciation takes place at a declining rate, indicating a looming ceiling. Instead, while some regularities emerge, these tend to be confined to upward trends that are not self evidently concave: there seems to be scope for some further, noticeable growth. These patterns may well illustrate how field growth is not only influenced by physical characteristics but also by discrete changes in economic conditions and technology—another topic, another paper.

Notes

1. Attanasi and Root (1994, p. 321).
2. For example, see Adelman (1993).
3. Note that field growth can result from finding new reservoirs within a field—often well after the initial discovery, especially onshore. To give one example, in Alberta the Clive D2-B pool was discovered about 20 years after the D2-A pool.
4. For example, see Odell and Rosing (1974).
5. Mentioned in Attanassi (2000, p. 63).
6. Reserve terminology varies. In Alberta, for instance, the term "initial reserves" is preferred to the term 'recoverable reserves' used in this paper. In my earlier working paper [Watkins (2000)]. I used the Alberta terminology.
7. Bohi (1999, p. 74).
8. Bohi, *ibid.,* and Watkins and Streifel (1998, p. 43).
9. These are drawn mainly from Smith Rae Energy Associates (1999).
10. The name of the field is suppressed.
11. For more details, see Watkins (2000, pp. 9–11).
12. Appendix D in Watkins (2000) provides additional details on sources and a tabulation of key field data for both the UK and Norwegian sectors.
13. For discussion of reserve definitions in the US and Canada, and outside of North America, see Adelman et al. (1983, chapters 4 and 9).
14. These fields were Angus, Argyll, Brae West, Captain, Crawford, Duncan, Innes, Linnhe, Staffa (UK) and Mime (Norway).
15. Possible influences from reserve definition in the two sectors are discussed in Section 6.
16. The preponderance of small fields would be even greater if discovered but undeveloped fields were included. According to Alex Kemp, the UK sector contains about 300 such fields of which the great majority are small.

17. However, research by Smith and Ward (1981) using data for 99 North Sea discoveries prior to 1977 found that while the lognormal distribution gave a reasonable fit to field size, it was not the preferred generating process. The reserve data used by Smith and Ward included natural gas fields converted at thermal equivalence to oil.
18. In terms of production, the contribution of small fields has risen in the UK sector over the past decade, while for Norway medium sized fields have contributed more in recent years [see Sem & Ellerman (1999, p. 6)].
19. The term "gross reserves appreciation" is used to distinguish it from "net reserves appreciation," a term that could apply to remaining reserves.
20. A point made by Alex Kemp.
21. As might be expected of the difference between two lognormally distributed populations.
22. Depth data were absent for 8 UK fields. Note the measurement is water depth, not field depth; field depth data were not available.
23. Gravity data were missing for 10 UK fields.
24. If production were a fixed proportion of total recoverable reserves by field, there would be no distribution—the RPR would be a single number: the uniform depletion rate.
25. In Section 5, appreciation factors are also defined in terms of oil-in-place.
26. Even within intensively drilled areas of the US, field growth is regularly underestimated; see Root and Attanasi (1993, p. 550).
27. Attanasi and Root (1994, p. 323).
28. See Watkins (2000, Appendix C), where Charts C-1 dealt with UK fields; Charts C-2 with Norway.
29. By way of contrast, Attanasi [World Oil (April, 2000, p. 84)] finds that in the Gulf of Mexico OCS, when fields are grouped by year of discovery, reserves for each group increase more or less systematically over time.
30. Sem and Ellerman suggested this division in earlier work [see Sem & Ellerman (1999)].
31. Chalk residues tend to constrain production in early years, but later subsidence of the formation increases reservoir pressure and the ability to recover reserves [see Sem & Ellerman (1999), p. 14)].
32. For example, in terms of "cross effects," Sem and Ellerman find depletion rate differences among size categories were not significant beyond initial years of production (op cit., p. 16).
33. Onshore reserve growth functions initially tend to increase more rapidly than functions for offshore fields. Offshore delineation continues in years following discovery but production is commonly delayed until production platform installation. Onshore field development and production usually occur quickly after discovery.
34. Alberta data were analyzed on a reservoir rather than field basis.
35. Adelman (1962, p. 5).
36. The sparse number of degrees of freedom discouraged testing for higher order autocorrelation.

37. This can arise in the econometric package used (EViews) when the intercept term is not estimated.
38. These were Cormorant South, Highlander, Innes, Ivanhoe, Maureen, Osprey and Piper.
39. The Ula, Hod and Heimdal fields.
40. Estimation of the nonlinear function was sensitive to the choice of initial values for the coefficients. Similar sensitivity was recorded in work by Wiorkowski (1977) as reported by Kaufman (1979).
41. If the 11% oil-in-place appreciation factor held for all UK fields on average, then the 22% average appreciation of initial recoverable reserves calculated earlier (see Section II) would imply increases in average UK recovery factors.
42. North Sea operators learnt from U.S.A. and Abu Dhabi experience not to let reservoir pressure fall below the bubble point (gas release pressure) after which the flow of liquids is impeded by gas bubbles. In the U.S.A., water injection was the remedy; in Abu Dhabi large scale sea water injection was used. I am indebted to Mervyn Grist for this point.
43. Substantial "uplift" for the Petroleum Revenue Tax (PRT) is given for investment before payback; no "uplift" is awarded for incremental investment made after payback.
44. Suggestion from discussion with the Norwegian Petroleum Directorate.

Acknowledgements

I wish to thank Samantha Ward of the University of Aberdeen for her extensive, sterling research assistance. I wish to also thank Eric Mathiesen of the Norwegian Petroleum Directorate and Mervyn Grist of the UK Department of Trade and Industry for providing information and advice. Valuable comments were received on a longer version of this paper [Watkins (2000)] from Morris Adelman (MIT), Denny Ellerman (MIT), Graeme Simpson (University of Aberdeen), Alexander Kemp (University of Aberdeen), James Smith (Southern Methodist University), Andre Plourde (University of Alberta), Emil Attanasi (US Geological Survey), John Schuenemeyer (University of Delaware), and George Warne (World Petroleum Congress), and on this version, from Peter Odell (Erasmus University). I also thank participants in seminars and workshops at the University of Aberdeen and MIT for advice. The usual disclaimer applies.

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