Tax or Technology?

The Revival of UK North Sea Oil Production

Steve Martin

Oxford Institute for Energy Studies

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The raw data underpinning much of the analysis contained in this study come from the UK Department of Trade and Industry's '*Brown Book*' and from Wood Mackenzie's *North Sea Service*. However, the results presented in Chapters 3 to 6, which simulate the impact of new technology and fiscal changes on the internal rate of return of individual fields, are based on my own cost assumptions and taxation model.

Steve Martin

Executive Summary

Oil production in the UK North Sea reached a peak of 2.63 million b/d in 1985. As widely predicted in the 1970s and early 1980s, output then declined sharply, down to 1.8 million b/d in 1991. The surprising feature of subsequent production development was a resumption of growth after the 1991 trough to a new peak of 2.49 million b/d in 1995.

This large increase in oil output between 1991 and 1995 occurred despite a considerable decline from fields where production had began before 1985 (*The 1985 Group* of fields as they are labelled in this study). These fields which, of course, accounted for the whole UK North Sea output of 2.63 million b/d in 1985 produced only 1.08 million b/d in the second peak year of 1995, while *The New Fields* (those brought into operation after 1985) contributed 1.42 million b/d. More tellingly, *The New Fields* added almost 1 million b/d to UK North Sea oil production between the 1991 trough and the 1995 peak, making up for a decline from the old fields of 0.31 million b/d during this period, and adding a net increase of 0.67 million b/d to the total.

Different factors may explain this resurgence of UK North Sea oil production. Economists tend to focus on prices to explain changes in output, but the price of oil was not much higher in the period 1991-5 than it was between 1985 and 1990 (ignoring the short Gulf War episode). In fact, two other significant factors were at play throughout the 1980s and early 1990s. The first was a relaxation of the petroleum fiscal regime in the UK, which influenced the prospective rate of return on certain projects. The second was a vast array of technological changes, which resulted in major cost reductions. Both sets of factors turned hitherto unattractive projects into commercially viable ones.

An answer to the question of 'how much of the oil production increase in the UK North Sea may be attributed to lower taxes, how much to lower costs, and how much to other factors' has not yet been provided in the public domain. This study attempts to provide such an answer.

The methodology used is simple in outline but inevitably required a large number of assumptions and the exercise of informed judgement. To isolate the 'fiscal effect', we have measured the reduction in output (from actual) that would have obtained had the key fiscal changes of 1983 and 1993 not been enacted. We assume that all other factors held as actual. In other words, the assumption of this scenario is that companies benefited from the cost-reducing technological progress, but not from the alleviation of the fiscal burden.

To isolate the 'technology effect', we have measured the reduction in output (from actual) that would have obtained had the technology of North Sea production remained unchanged in the 1980s and early 1990s, say with the continuing use of conventional production platforms, instead of the devices invented since. We assume that all other factors evolved as they actually did.

Cash flow models were constructed under these scenarios. Fields which generated an internal rate of return (IRR) of less than 15 per cent in these models were deemed non-commercial, and the assumption is that they would not have been brought into production. The exercise could be performed using alternative rates of return, and the paper provides some results of IRR of 10 per cent and 20 per cent.

The first scenario suggests that the alleviations of the fiscal regime in 1983 and 1993 were responsible for making seven new fields commercial (at IRR $\geq$15 per cent). These were Alba, Brae East, Bruce, Dunbar, Eider, Miller and Strathspey.

The second scenario indicates that, without technological changes, seventeen fields would not have been commercial. These were Angus, Arbroath, Birch, Blenheim, Chanter, Columba D, Donan, Fife, Glamis, Leven, Medwin, Moira, Ness, Osprey, Pelican, Petronella and Strathspey.

Strathspey, which belongs to both lists, needed a *combination* of the fiscal and technological boost. In addition, Ivanhoe/Rob Roy (two fields for which we applied a single cash flow) would have crossed the profitability threshold thanks to *either* the fiscal or the technology effect. It needed any one of these, not both.

New technology was introduced for the development of some old fields (the pre-1985 vintage). The new technology enabled Argyll, Deveron, Duncan, Innes and Scapa to yield rates of return higher than 15 per cent.

Compare actual production in 1991, the trough year, with 1995, the recent peak year. The net increase was 665,000 b/d, resulting from a decline of 312,000 b/d from old fields and a contribution of 977,000 b/d from new fields.

This 977,000 b/d increase from the fields that came into production after 1985 can be attributed as follows:

	'000 b/d	*% of the increase*
(1) Contribution from fields developed as a result of the fiscal changes only	355	36.3
(2) from fields developed as a result of technological changes only	109	11.2
(3) as a result of either (both) fiscal or (and) technological changes	13	1.3
(4) from fields that would have been developed in any case	397	40.6
(of which Scott and Nelson)	(346)	(35.4)
(5) from fields which were developed even though their IRR *ex post* turned out to be less than 15 per cent	103	10.9
Total	**977**	**100.0**

The major contribution to the resumption of growth (40.6 per cent) came from fields that would have been commercial anyway. Neither fiscal changes nor technological progress were necessary to move them above the threshold. Both however contributed to increase the profits of the companies involved. Of these fields, Nelson and Scott accounted for the lion's share.

Fiscal relaxation comes next in order of importance (36.3 per cent). Meanwhile, the contribution to the increase between the trough of 1991 and the peak of 1995 as a result of new technology was relatively small. It is interesting to note that the contribution from apparently 'non-commercial' fields (i.e., those with IRRs below 15 per cent) was almost as high as from those developed that benefited from new cost-saving methods of production.

We can look at the results differently, by considering the cumulative production of the new fields, instead of the 1991-5 increment. The cumulative production of new fields from 1986 to 1995 was 1,932.7 million barrels. This can be attributed as follows:

	million barrels	*% of cumulative production*
(1) Contribution from fields developed as a result of the fiscal changes only	396.1	20.5
(2) from fields developed as a result of technological changes only	299.1	15.5
(3) as a result of either (both) fiscal or (and) technological changes	160.7	8.3
(4) from fields that would have been developed in any case	414.3	21.4
(of which Scott and Nelson)	(245.3)	(12.7)
(5) from fields which were developed even though their IRR *ex post* turned out to be less than 15 per cent	662.5	34.3
Total	**1,932.7**	**100.0**

As regards the cumulative production of new fields over the period 1985-95, the largest contribution came from fields (34.3 per cent) that were developed even though their IRR turned out to be *ex post* less than 15 per cent. The second largest contribution (21.4 per cent) was made by fields which would have yielded an IRR higher than 15 per cent irrespective of the fiscal or technological boost. The contribution of technology to cumulative production is greater than its contribution to the resumption of growth from 1991 to 1995. It seems that technology enabled the development of fields that peaked early.

Furthermore, new technology has contributed to an increase in production from old fields, which is not reflected in the numbers presented above. It is estimated in this study that technology-induced increases in reserve estimates from the established fields (that are due to the reclassification of some of the original oil-in-place from uneconomic to economically recoverable as the result of technology-induced cost reductions) total over 2.7 billion barrels of oil since 1985. Once this is taken into account, the role of new technology in bringing forth additional reserves of oil from the UK North Sea sector becomes much more pronounced. It should also be borne in mind that advances in exploration technology, which are not modelled in this study, have resulted in the discovery of fields that might otherwise have gone undetected, or have enabled a more accurate appraisal of fields, on which the decision to develop has been based.

The study includes sub-scenarios which assume different types of fiscal relaxation. It looks also at the impact of changes on old oilfields and on gas fields (which have associated liquids production). Different levels for the rate of return are used to test sensitivity.

The impact of fiscal and technological changes on the government take, the addition to oil reserves, and on company cash flows has also been estimated.

The contribution of fiscal and technological changes on *all* fields may have added 6.4 billion barrels to recoverable reserves.

The fiscal relaxation of 1983 and 1993 increased government tax take, over the expected lifetime of the fields, by £2 billion as a result of the production induced through new fields. But it is reduced by £5.3 billion from old fields because new tax rates were offered to the whole sector. The net result was an estimated loss of £3.3 billion to the Treasury (not allowing, however, for the gains made from the abolition of relief for exploration in the 1993 Finance Act).

The changes also boosted company net cash flows, gross revenues and investment flows over the expected life of fields.

Tax or Technology? The Revival of UK North Sea Oil Production

Table of Contents

EXECUTIVE SUMMARY ..... **i**

INTRODUCTION ..... **xi**

CHAPTER 1: PROFILE OF UK NORTH SEA OIL PRODUCTION

INTRODUCTION 1

CHANGES IN UK NORTH SEA OIL PRODUCTION 2

THE 1985 GROUP VERSUS NEW FIELDS 3

Trends in Production Since 1985 3

Changes in the Number of Operating Fields 7

Average Oil Production Per Field 7

THE SIZE STRUCTURE OF UK NORTH SEA OIL FIELDS 8

Evolution in the Field Size Profile of UK North Sea Oil Production Since 1985 10

SUMMARY POINTS 12

CHAPTER 2: FACTORS INFLUENCING CHANGES IN NORTH SEA OIL PRODUCTION

FACTORS AFFECTING THE DEVELOPMENT DECISION 14

The Price of Oil 14

The UK Fiscal Regime 16

The Impact of New Technology 21

Exploration and Seismic Technology 22

New Production and Drilling Technology 23

Changes in the Internal Organisation of the Oil Industry 26

Cost Reduction Initiative for the New Era (CRINE) 27

The Relationship Between Operators and Their Suppliers 27

Infrastructure 29

Gas Considerations 31

Interaction Between the Various Factors 31

THE SIGNIFICANCE OF THE TIMING OF NEW DISCOVERIES 32

SUMMARY POINTS 33

CHAPTER 3: THE IMPACT OF FISCAL REFORM

INTERNAL RATE OF RETURN 36
MPACT OF DIFFERENT TAX SCENARIOS ON FIELDS' INTERNAL RATES OF RETURN.......... 38
Results of the Analysis 39
SUMMARY POINTS 42

CHAPTER 4: THE IMPACT OF COST-SAVING NEW TECHNOLOGY

METHODOLOGY 43
Choosing a 'Representative' Capital Cost 44
Choosing Appropriate Operating Costs 44
Other Assumptions 45
ANALYSIS OF THE RESULTS 46
THE IMPACT OF NEW TECHNOLOGY ON PRODUCTION FROM *THE 1985 GROUP* OF FIELDS49
Distinguishing Between 'Reserve Creep' and Technology-Induced Reserve Increases 51
SUMMARY POINTS 54

CHAPTER 5: COMPARING THE FISCAL AND TECHNOLOGY EFFECTS

ANALYSIS OF THE RESULTS 55
The Development Decision 58
IMPACT ON PRODUCTION 62

CHAPTER 6: THE IMPACT OF FISCAL CHANGES AND NEW TECHNOLOGY ON RESERVES AND FINANCIAL INDICATORS

FORTHCOMING ADDITIONAL RESERVES SINCE 1985 AT DIFFERENT TARGET IRRS UNDER THE DIFFERENT SCENARIOS 65
FINANCIAL IMPLICATIONS 67
Gross Revenue 69
Government Tax Take 70
Total Costs and Investment 71
Company Cash Flow 71
Total Contribution to Company and Government Finance 72
Summary of the Financial Implications of the Fiscal and Technology Scenarios 72
TAKING THE ESTABLISHED FIELDS INTO ACCOUNT 73
Measuring the Change in Tax Take 74
Incorporating Technology-Induced Reserve Increases 76
SUMMARY POINTS 78

ANNEX 1: SIZE STRUCTURE OF UK NORTH SEA OIL FIELDS 81

ANNEX 2: DETAILS OF UK OIL FISCAL CHANGES AND UK LICENSING ROUNDS .. 84

ANNEX 3.1: DESCRIPTION OF THE TAXATION MODEL 88

ANNEX 3.2: RESULTS OF THE DIFFERENT FISCAL SCENARIOS 93

ANNEX 4: COST METHODOLOGY 95

ANNEX 5.1: SENSITIVITY OF RESERVE BASE TO DIFFERENT TARGET IRRS 111

ANNEX 5.2: CALCULATION OF TAX SACRIFICED FROM ESTABLISHED FIELDS AS A RESULT OF PRT FALLING FROM 75 TO 50 PER CENT 114

BIBLIOGRAPHY 116

List of Tables

Table 1.1: UK North Sea Production - *The 1985 Group* and *The New Fields* 4
Table 1.2: Number of Operating Oilfields in the UK North Sea Sector 7
Table 2.1: Number of Annex B Approvals Granted, 1973-95 18
Table 2.2: Spare Capacity within Major UK North Sea Pipeline Systems 30
Table 2.3: *The New Fields* Discovered after 1985 32
Table 3.1: *The New Fields* - Base Case Internal Rates of Return 37
Table 3.2: Fields where, given Existing Technology, the 1983 and 1993 Fiscal Changes have Influenced their Development 41
Table 4.1: Comparison of the Internal Rates of return under the Base Case and in the Absence of New Technology 47
Table 4.2: Fields where, given the Existing Fiscal Regime, Cost-Saving Technology has Influenced their Decelopment 49
Table 4.3: The 1985 Group - Increase in Estimates of Recoverable Reserves 53
Table 5.1: Comparisons of IRRs under Different Scenarios 57
Table 5.2: Fields with Base Case IRRs below 15 Per Cent 59
Table 5.3: Comparison of UK North Sea Oil Production in 1991 and 1995 by Type of Effects64
Table 6.1: Range of Forthcoming Additional Reserves under Different Scenarios at Target IRRs of 10%, 15% and 20% 66
Table 6.2: Financial Indicators under Different Scenarios - £ million 69
Table 6.3: Financial Indicators under Different Scenarios - Percentage Change from Base Case 69
Table 6.4: Net Change in Government Tax Take as a Result of the 1983 and 1993 Fiscal Changes 75
Table 6.5: Change in Financial Indicators and Recoverable Reserves as a Result of the Fiscal Changes of 1983 and 1993 - All Fields 75
Table 6.6: Forthcoming Reserves under Different Scenarios - Incorporating Established Fields 77

ANNEX TABLES

Table A1.1: Size of UK North Sea Oil Fields in Terms of Recoverable Oil Reserves 81
Table A2.1: Chronology of Key Changes to the UK Fiscal Regime 84
Table A2.2: Licensing Rounds and Discovery of UK North Sea Oil Fields 85
Table A3.1: The Rate of Petroleum Revenue Tax 90
Table A3.2: Total Tax Bills of *The New Fields* under Different Scenarios 93
Table A3.3: Internal Rates of Return of *The New Fields* under Different Fiscal Scenarios .. 94

Table A4.1: Results of Regression of Platform Costs against Water Depth, Total Reserves, Year of Construction, Construction Material & Location in the North Sea 95
Table A4.2: Cost of Platform Structures, Equipment and Installation 97
Table A5.1: The Established Fields: Change in Tax Take as a Result of the Change in PRT from 75 to 50 Per Cent 115

List of Diagrams

Diagram 1.1: UK North Sea Oil Production Since 1980 2
Diagram 1.2: UK North Sea Oil production - *The 1985 Group* and *The New Fields* 5
Diagram 1.3: Production from *The 1985 Group* of Fields 6
Diagram 1.4: Average Oil Production per Field (Incorporating Forecasts) 8
Diagram 1.5: *The New Fields* - Composition of Annual Output by Size of Field 11
Diagram 1.6: Trend in Size Distribution of Annual UK North Sea Oil Output 11
Diagram 2.1: Relationship between UK North Sea Oil Production and the Oil Price 15
Diagram 2.2: Major Changes to the UK Oil Fiscal Regime 17
Diagram 2.3: UK Offshore Drilling Activity 20
Diagram 4.1: *The 1985 Group* - Extension to Lifespans 51
Diagram 5.1: UK North Sea Oil Production under Different Scenarios 63
Diagram 6.1: Sensitivity of Fiscal and Technology Scenarios to the Choice of Target IRR 67

ANNEX DIAGRAMS

Diagram A1.1: Cumulative Oil Reserves versus Field Numbers 82
Diagram A1.2: Number of Fields by Size Category 82
Diagram A1.3: *The 1985 Group* - Distribution of Cumulative Production Since 1985 by Size of Field 83
Diagram A1.3: *The New Fields* - Distribution of Cumulative Production Since 1985 by Size of Field 83
Diagram A4.1: Real Weighted Average per Barrel Costs by Type of Structure 99
Diagram A4.2: Real Weighted per Barrel Costs of Conventional Platforms by Size of Reserves 100
Diagram A4.3: Percentage Breakdown of Costs between Capital and Operating Expenditure by Type of Structure 101
Diagram A4.4: Typical Breakdown of Platform Operating Costs 102
Diagram A4.5: Alba - Real per Barrel Operating Costs 102
Diagram A4.6: Fulmar - Real per Barrel Operating Costs 103
Diagram A4.7: Nelson - Real per Barrel Operating Costs 103
Diagram A4.8: Tern - Real per Barrel Operating Costs 104

Diagram A4.9: Eider - Real Annual Operating Costs 106
Diagram A4.10: Kittiwake - Real Annual Operating Costs 106
Diagram A4.11: Lomond - Real Annual Operating Costs 107
Diagram A4.12: Montrose - Real Annual Operating Costs 107
Diagram A4.13: Auk - Real Annual Operating Costs 108
Diagram A4.14: Clyde - Real Annual Operating Costs 108
Diagram A4.15: Heather - Real Annual Operating Costs 109
Diagram A4.16: NW Hutton - Real Annual Operating Costs 109
Diagram A4.17: Saltire - Real Annual Operating Costs 110
Diagram A4.18: Tartan - Real Annual Operating Costs 110
Diagram A5.1: Reserves Forthcoming at Different Target IRRs - Base Case 111
Diagram A5.2: Reserves Forthcoming at Different Target IRRs - Without the 1983 and 1993 Fiscal Changes 112
Diagram A5.3: Reserves Forthcoming at Different Target IRRs - Without New Technology 113
Diagram A5.4: Reserves Forthcoming at Different Target IRRs - Without Both New Technology and Fiscal Changes 113

Introduction

In the 1970s and beginning of the following decade, it was widely forecast that United Kingdom (UK) North Sea oil production would reach an early peak before declining rapidly. Certainly, the evolution of output in the 1980s adhered to this predicted pattern. In the first half of the 1980s, UK North Sea oil production rose rapidly, rising from 1.6 million barrels per day (b/d) in 1980 to a peak of 2.6 million b/d in 1985. This was followed, during the latter part of the decade and beginning of the 1990s, by a dramatic decline in oil supplies, which had slumped to 1.8 million b/d by 1991.

However, rather than a continuation of this downward trend, the remainder of the 1990s has witnessed a *resurgence* in production, proving wrong the pundits of the 1970s/early 1980s. Output reached a second peak of around 2.5 million b/d in 1995, with further increases in supplies expected before the turn of the century. The UK is now firmly established as one of the world's top ten oil producers.

This recovery in production has been attributed to a number of factors. The oil industry tends to emphasize new technology. The UK has been at the forefront of technological progress within the upstream oil sector, and cost-saving technology has enabled the development of fields that would otherwise have remained unexploited. Moreover, improved oil recovery techniques have boosted output from the older, established oilfields, and have helped to slow the rate of decline in production from these developments.

Other commentators believe that activity in the UK North Sea sector has been strongly stimulated by successive relaxations in the fiscal regime, particularly in 1983 and 1993, which have improved the economic viability of new oilfield ventures and encouraged further investment in existing fields.

One of the main objectives of this study is to gauge the relative contributions made by new technology and fiscal measures in the upturn in oil output during the 1990s. There is a dearth of research available in the public domain that provides a *systematic* analysis of the factors underpinning the recovery in UK North Sea oil production. This study aims to remedy this situation. The examination of the relative contribution of fiscal relaxation and cost-reducing technological progress provides valuable lessons to other oil-producing countries that are inviting international oil companies to explore for and develop their hydrocarbon resources.

The study consists of six chapters. Chapter 1 profiles the trend in UK North Sea oil production over the past decade or so. It makes a distinction — which is used throughout the study — between the older, established oilfields (referred to as the *'The 1985 Group'* and consisting of those fields that were already on stream by 1985, the starting point of much of the analysis), and those fields that have been developed in recent years (termed *'The New Fields'*, and defined as those fields that started producing oil *after* 1985).

In Chapter 2, the key factors that have had an important bearing on activity in the UK North Sea sector are discussed. These include the price of oil, the UK fiscal regime, advances in technology, the timing of discoveries, infrastructure and gas considerations.

Chapters 3, 4 and 5 present cash-flow analyses designed to model the impact of fiscal changes and cost-saving new technology on the economics of new field developments. By assuming that operators will only proceed with the development of a new field if it achieves a target internal rate of return, the model highlights which fields have been developed as a result of a relaxation in the UK fiscal regime, and which owe their existence to technological progress. The importance of other factors in the development decision is also isolated.

Chapter 6 considers further aspects of the roles played by fiscal changes and new technology in the evolution of the UK North Sea oil sector over the past decade. In addition to summarizing the relative importance of the various factors on the size of the reserve base since the mid 1980s, the chapter considers the financial implications associated with different fiscal and technology scenarios, including a financial assessment of how successful the UK government has been in stimulating activity in the UK North Sea oil sector through modifications of the fiscal regime.

Chapter 1: Profile of UK North Sea Oil Production

INTRODUCTION

Exploration in the North Sea began in 1964, with the first oil discovery being made in late 1966. Norway was responsible for the first full-scale development in 1971, and oil production from the United Kingdom Continental Shelf (UKCS) did not commence until 1975. The exploitation of North Sea oil reserves was fairly slow in the early stages, reflecting the region's harsh weather conditions and the absence of any local infrastructure, which made the development of oilfields a costly and risky venture.

However, North Sea oil exploitation received a boost in the 1970s from changes in the circumstances of the international oil industry. Oil companies became increasingly concerned about their property rights in the OPEC region because of a wave of nationalization, and demands by host governments for equity participation in the concessions. In response, oil companies sought to diversify their sources of production into other geographic regions. Subsequently, the hefty oil price increases in the 1970s improved the economics of exploration and development of oil reserves in high cost areas such as the North Sea.

By the time that oil output from the UK North Sea came on-stream in 1975, gas production from the Southern North Sea was already established.[1] However, since the late 1970s, oil output has exceeded gas production (in oil equivalent terms). Moreover, the relative importance of oil vis-à-vis gas in the UK North Sea sector is demonstrated by the greater than 60 per cent share of total offshore recoverable reserves in the UK accounted for by oil (when both oil and gas reserves are expressed in barrels of oil equivalent).

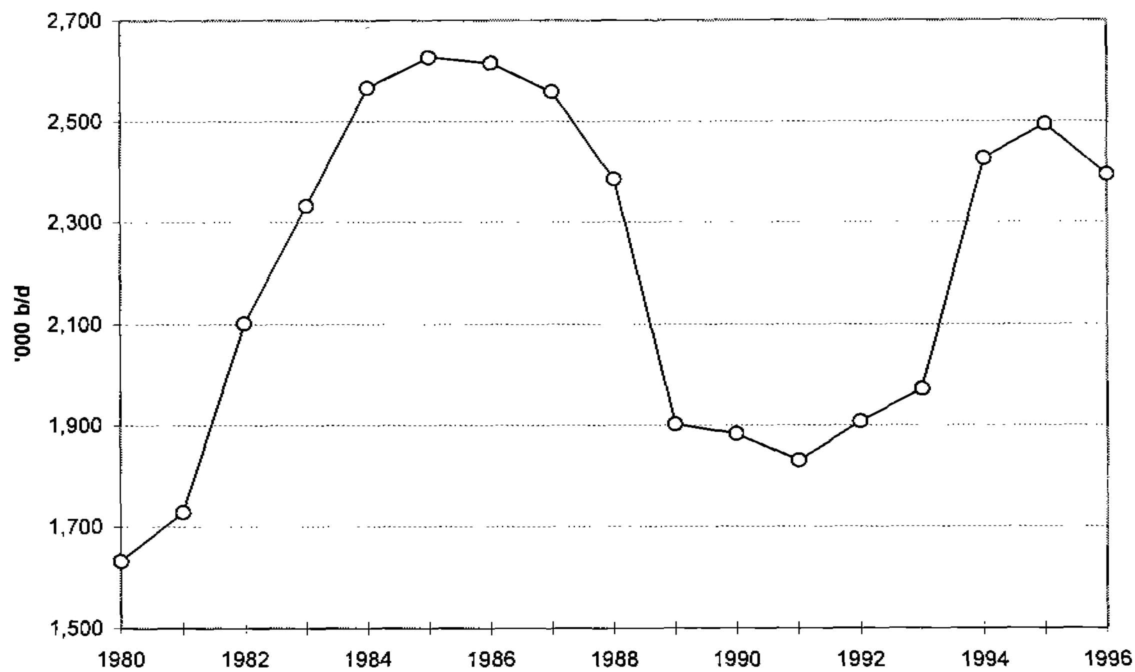
In the UK, the development of oil (and gas) production from the North Sea makes a valuable contribution to the economy as a whole. It is estimated that the sector currently represents around 2.5 per cent to the UK Gross Domestic Product — it has reached 7 per cent when oil prices have been high — employs around 24,500 people directly (and many others *indirectly* in other sectors such as construction), accounts for around 20 per cent of total UK industrial investment, and has made a considerable positive contribution to the UK balance of payments (*The Energy Report*, DTI, 1997).

[1] The dynamics of UK gas production are examined by Michael Stoppard in *The Resurgence of UK Gas Production*, Oxford Institute for Energy Studies, 1994.

CHANGES IN UK NORTH SEA OIL PRODUCTION

Diagram 1.1 depicts UK North Sea oil production from 1980 to 1996.[2] UK oil output from the North Sea rose steadily during the first half of the 1980s, increasing by a total of around 1 million b/d between 1980 and 1985, peaking at around 2.63 million b/d in 1985.

Diagram 1.1: UK North Sea Oil Production Since 1980



In the latter half of the 1980s, UK North Sea oil production entered a period of decline, falling particularly dramatically — by over 20 per cent — between 1988 and 1989. This was not entirely due to the Piper Alpha tragedy[3] in 1988. Piper was one of the larger fields in operation at the time, accounting, on average, for approximately 7 per cent of total UK North Sea oil production during the three years prior to the tragedy. Moreover, since the Piper Alpha platform was the starting point for the Flotta pipeline system, the suspension of operations at Piper also rebounded on oil production at the other fields using this pipeline: Claymore, Scapa, Tartan, Highlander and Petronella.

However, the blame for the sharp drop in production between 1988 and 1989 cannot be laid *solely* at the door of Piper. An analysis of the production change between these two

[2] The source of the data is Wood Mackenzie's North Sea Service. The figures represent annual averages. The data do *not* include UK onshore oil production, output from west of Britain oilfields (Douglas and Lennox) and test production from fields that are not on stream. For 1996, only production from fields that were on stream during the first half of the year (i.e., January to June) is included.

[3] On 6 July 1988, the Piper Alpha platform was destroyed by a series of explosions, which were sparked by a gas leak from a faulty valve. Production from Piper ceased completely. The field was subsequently redeveloped, with the new (Piper Bravo) platform coming into operation in February 1993.

years reveals total UK North Sea output dropped by 484,000 b/d, but only 84,000 b/d of this decline can be attributed to the fields that were affected by the Piper tragedy. In other words, even if tragedy had not struck at Piper in 1988, UK oil production would have *still* fallen significantly between 1988 and 1989 as a result of other factors (which are addressed later in this chapter).[4]

UK North Sea oil output continued to decline after 1989, albeit at a much slower rate, before reaching a trough of 1.83 million b/d in 1991. Thereafter, production has staged a strong recovery, reaching a second peak of close to 2.5 million b/d in 1995, before slipping back slightly in 1996. The upturn in output was particularly marked between 1993 and 1994, when production expanded by almost 450,000 b/d, or by 23 per cent.

THE 1985 GROUP VERSUS NEW FIELDS

For much of the analysis contained in this study, a distinction is made between two categories of oilfield:

- *The 1985 Group*, which are those fields already on stream in 1985; and
- *The New Fields,* which are those fields that commenced operations *after* 1985.

1985 has been chosen as the starting point of the analysis because it represents the year of the first peak in UK North Sea output, and enables the impact of the key fiscal changes of 1983 (described in Chapter 2) to be incorporated into the analysis. Moreover, since alternative methods of exploiting oilfields (i.e., without a conventional production platform) started becoming popular in the mid 1980s, it seems sensible to take this period as a reference point. As will become apparent in the following sections of this chapter, the choice of a later year as the starting point, such as 1991 — which was the year of trough production — would not allow for sufficient lead times for many of the new fields coming on stream, thereby disguising the dynamics in oil production that have taken place.

Trends in Production Since 1985

Table 1.1 presents the evolution of oil production on a year-by-year basis since 1985 from *The 1985 Group* of fields and *The New Fields.* Two opposing trends emerge. Since 1985, output from *The 1985 Group* has steadily fallen, reflecting the mature nature of these fields. By 1985, many of them had already passed their production peaks, and had entered the

[4] Unlike in other oil-producing countries around the world, these factors do *not* include a price-induced shut-in of capacity. UK oil production is not subject to a system of quotas (unlike OPEC members), and the UK government has yet to implement an effective depletion policy, which could potentially influence production decisions. As a result, UK oil producing capacity tends to be fully utilized (with the exception of periods of maintenance and disasters such as the Piper accident).

downward slopes of their production profiles. From levels of over 2.6 million b/d in 1985 and 1986, total production from *The 1985 Group* of oilfields has since declined by over 60 per cent to around 1 million b/d. Meanwhile, the production profile of *The New Fields* that have come on stream since 1985 moves in the opposite direction, with their oil output rising steadily to levels of around 1.4 million b/d in 1995 and 1996.

Table 1.1: UK North Sea Oil Production[1] - *The 1985 Group* and *The New Fields* ('000 b/d)

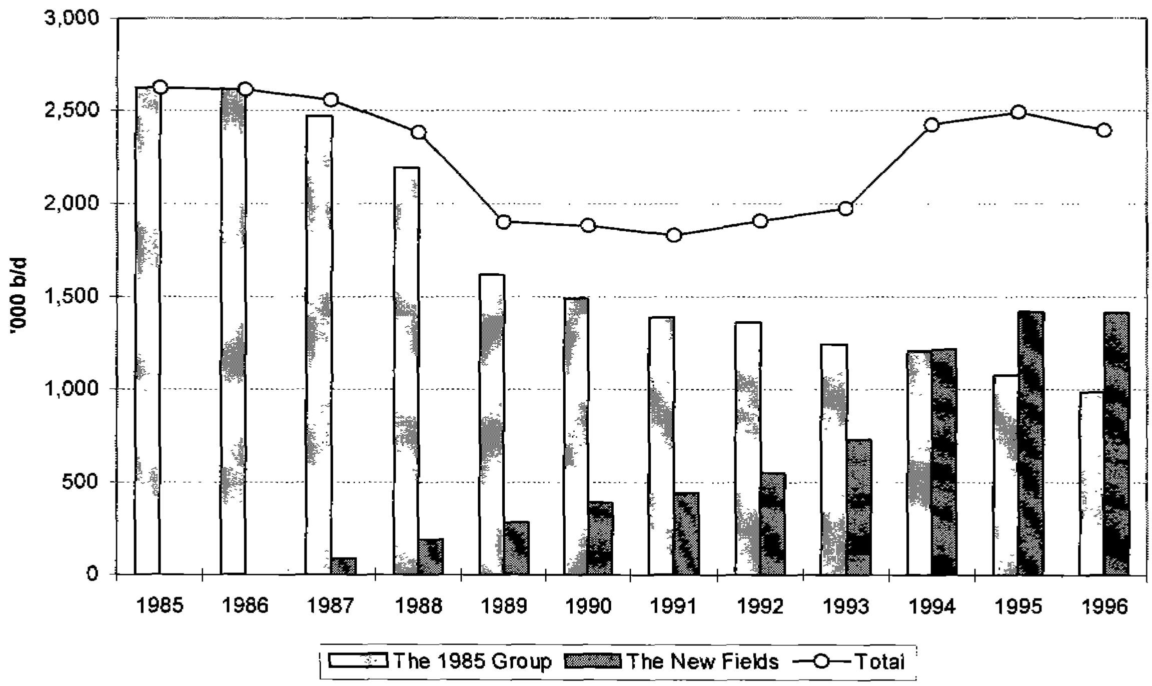
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
The 1985 Group	2,626	2,614	2,471	2,195	1,616	1,492	1,389	1,359	1,241	1,206	1,077	985
Year-on-Year Change		*-12*	*-143*	*-276*	*-579*	*-124*	*-103*	*-30*	*-118*	*-35*	*-129*	*-92*
The New Fields	0	2	87	190	285	390	440	548	730	1,220	1,417	1,410
Year-on-Year Change		*2*	*85*	*103*	*95*	*105*	*50*	*108*	*182*	*490*	*197*	*-7*
Total	**2,626**	**2,616**	**2,558**	**2,385**	**1,901**	**1,882**	**1,829**	**1,907**	**1,971**	**2,426**	**2,494**	**2,395**
Year-on-Year Change		***-10***	***-58***	***-173***	***-484***	***-19***	***-53***	***78***	***64***	***455***	***68***	***-99***
Percentage of Total Output												
The 1985 Group	100%	100%	97%	92%	85%	79%	76%	71%	63%	50%	43%	41%
The New Fields	0%	0%	3%	8%	15%	21%	24%	29%	37%	50%	57%	59%

Source: Wood Mackenzie

Note: [1] The data are annual averages, and do not include onshore production, output from West of Britain fields and test production from fields that are not on stream. For 1996, only production from fields that were on stream by June 1996 is included.

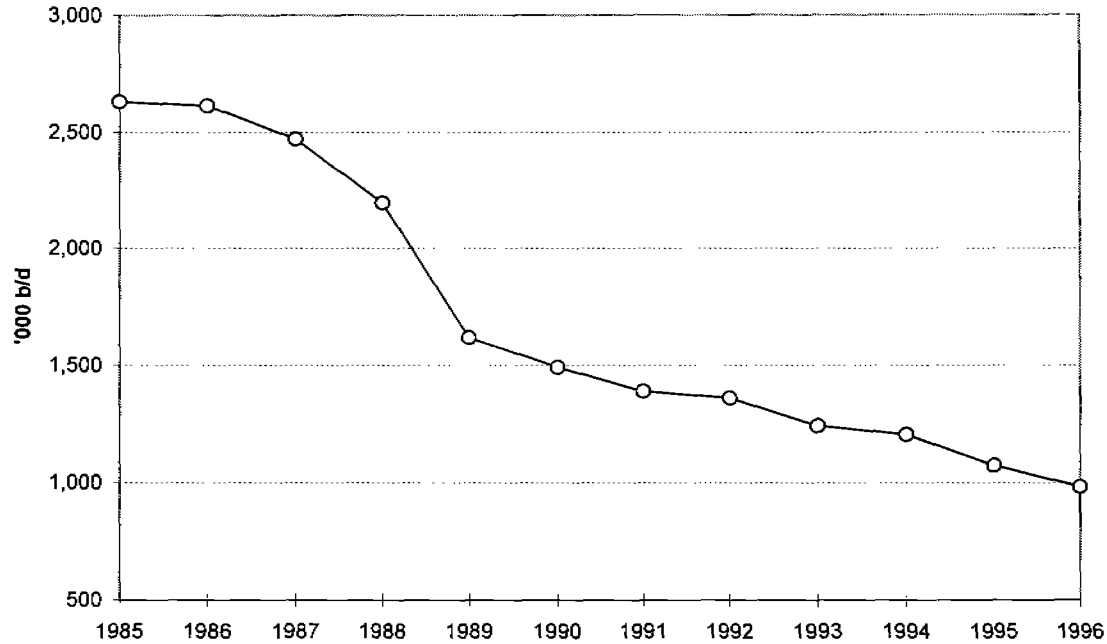
The production profiles of the two categories of North Sea oilfields are combined in Diagram 1.2, which reveals that, between 1986 and 1991, the output from *The New Fields* was only able to offset *partially* the decline in oil production from *The 1985 Group*. By 1991, *The New Fields* were producing 440,000 b/d, but this was insufficient to compensate for the 1.2 million b/d decline in production from *The 1985 Group* between 1985 and 1991. As a result, overall UK North Sea oil output fell. Since 1991, however, output from *The New Fields* has been more than sufficient to offset falling production from *The 1985 Group*, contributing to the revival in total UK North Sea oil output during the 1990s.

Diagram 1.2: UK North Sea Oil Production - *The 1985 Group* and *The New Fields*



The rate of decline in output from *The 1985 Group* has obviously had an important bearing on this ability of the newer generation of fields to make good the fall in production from the established fields. Diagram 1.3 charts the trend in production of *The 1985 Group* since 1985, and reveals that there was a big rate of decline between 1987 and 1989. Part of this can be explained by the impact of the Piper tragedy in July 1988. Total production from *The 1985 Group* declined by 579,000 b/d between 1988 and 1989. The fields affected by the accident on Piper accounted for less than 15 per cent (84,000 b/d) of this reduction. Thus, other factors were responsible for a large part of the decline. Events at the Brent field help to explain a large part of this behaviour. In 1989, production from Brent was affected by a series of accidents on the Brent platform and pipeline systems. Faults on the fire pumps of the Alpha platform, the failure of a gas compressor on Bravo, valve work on Charlie and a gas explosion on Delta all conspired to reduce Brent output by nearly 40 per cent in 1989.

Diagram 1.3: Production from *The 1985 Group* of Fields



After 1989, the line depicting *The 1985 Group's* production decline in Diagram 1.3 becomes more or less *linear*, which goes on unabated until 1996. There is a monotonic decrease of about 90,000 b/d per annum, which is an interesting characteristic. Put differently, this implies that the *percentage rate of decline* is increasing over time. If this monotonic decrease is extrapolated into the future, it would imply that production from *The 1985 Group* of fields would sink to 500,000 b/d by 2001, and would disappear entirely between 2006 and 2007.

Returning to Table 1.1, the changing *proportion* of annual UK North Sea production accounted for by the two groups of fields over the period is presented. As one would expect, the percentage contribution of the older *1985 Group* has declined over the past decade, while that of *The New Fields* has risen. Indeed, in 1995, *The New Fields* overtook (for the first time) *The 1985 Group* as the dominant producers in the North Sea, and in 1996, their share of overall production reached 59 per cent.

However, in terms of *cumulative* production since 1985, *The New Fields* still fall well short of the contribution made by *The 1985 Group.* An analysis of the data reveals that *The New Fields* still only account for a small share of the total oil recovered from the UKCS since 1985, although this share is rising modestly, and is approaching 25 per cent. However, total recoverable reserve estimates of each category of field suggest that *The 1985 Group* will always dominate the cumulative totals, with *The New Fields'* share of total UK North Sea oil production unlikely to rise much above 30 per cent in the future.

Changes in the Number of Operating Fields

Table 1.2 describes the changes in the *number* of oilfields that have taken place since 1985. As some of *The 1985 Group* of fields reach the end of their productive lives and are abandoned, so their number dwindles, although this is a very slow process.[5] Between 1985 and 1996, the number of *The 1985 Group* of oilfields declined by just four: from 31 to 27. As discussed in subsequent chapters of this study, the growing number of 'satellite' oilfields which are 'tied back' to existing platforms has helped to justify the continued operation of older platforms. Furthermore, improvements in oil recovery rates and subsequent upward revisions in estimates of recoverable reserves of many of the older fields have prolonged their lifespans. Another reason for the inertia is that the abandonment and decommissioning of oil platforms is becoming such a contentious issue on environmental grounds that oil companies are keen to prolong the life of existing facilities. Meanwhile, the number of *New Fields* has grown from just two in 1986 to 48 in the first half of 1996. Thus, the *total* number of UK oilfields operating in the North Sea has more than doubled over the last decade, rising from 31 in 1985 to 75 in the first half of 1996.

Table 1.2: Number of Operating Oilfields in the UK North Sea Sector

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	Jan-June 1996
The 1985 Group	31	31	31	31	30	30	29	29	28	28	27	27
The New Fields	-	2	5	7	14	19	19	26	38	44	45	48
Total	**31**	**33**	**36**	**38**	**44**	**49**	**48**	**55**	**66**	**72**	**72**	**75**

Average Oil Production per Field

Armed with the information on production and number of operating oilfields, it is possible to derive average oil production per field. Diagram 1.4 illustrates how this has evolved for each group of North Sea oilfields since 1985. In the case of *The 1985 Group* of fields, the trend is clearly downward. Average production of these fields has declined by more than 50 per cent over the course of the past decade, falling from approximately 85,000 b/d in 1985 to levels of around 40,000 b/d during the past couple of years. This is to be expected of these maturer fields: many of them passed their peak production levels many years ago, and are now approaching the end of their productive lives.

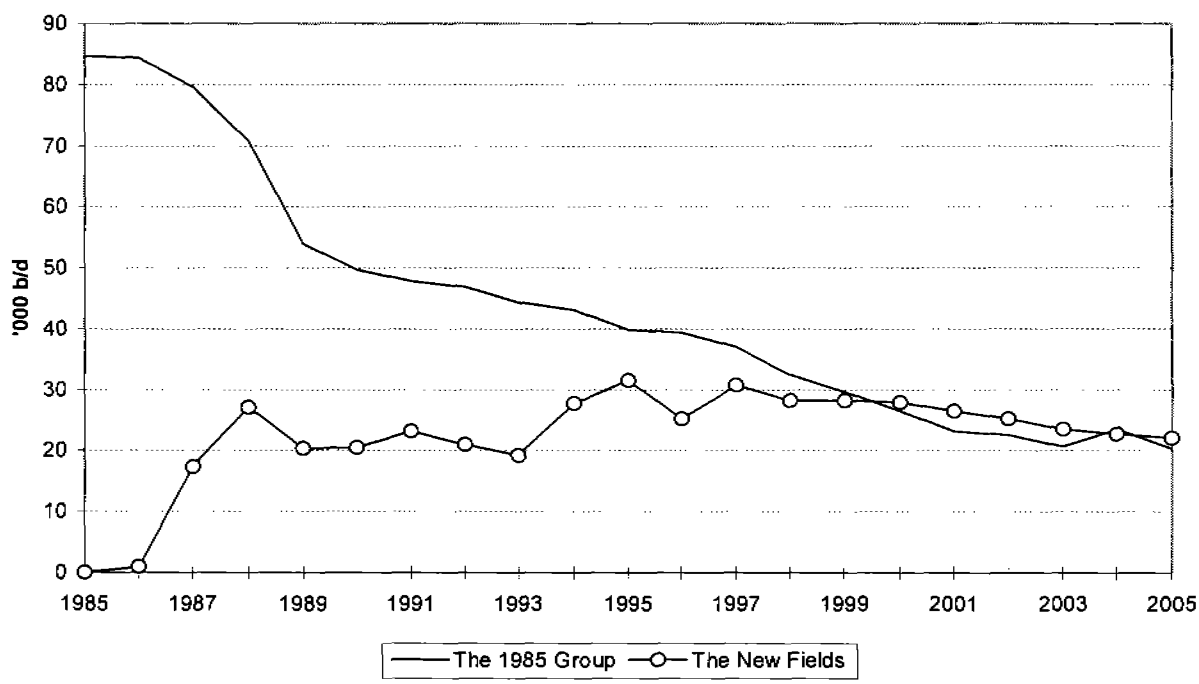
Average production from the oilfields belonging to *The New Fields* group, whilst still remaining below that of the older ones, has been rising gradually since the start of the period under examination, as these fields approach their peak production levels. Average

[5] The decline in number also reflects the Piper Alpha tragedy, which resulted in the temporary cessation of operations at Piper between 1989 and 1992.

output from these new fields has reached levels of approximately 30,000 b/d in 1995, although they fell back to 25 per cent in 1996.

An interesting feature of Diagram 1.4 is that it shows that average field production of the two groups is converging. To consider whether this trend will continue, projections of future oil output by field — derived from forecasts made by *Wood Mackenzie* in its North Sea Service (November 1996) — are included in the analysis. The figures suggest that the average productivity of *The 1985 Group* of oilfields will continue to drift downwards over the next ten years. However, in the case of *The New Fields*, average production per field is expected to peak in 1997 at levels of around 31,000 b/d, before easing back. From 2000 until 2005, the productivity of the two groups is forecast to be broadly similar, with average field production slipping to levels of around 20,000 b/d.

Diagram 1.4: Average Oil Production per Field (Incorporating Forecasts)



THE SIZE STRUCTURE OF UK NORTH SEA OILFIELDS

Although the above analysis reveals that average production levels from the two categories of field are converging over time, there nonetheless exists a marked contrast between the size structures of the oilfields within *The 1985 Group*, and those comprising *The New Fields*. These differences are examined in detail in this section. For the purpose of this analysis, oilfields are given a size classification which is based on their recoverable reserves of oil. The following definitions are used:

Very Large: 1,000 million barrels or more
Large: between 400 million and 1,000 million barrels
Medium: between 200 million and 400 million barrels
Small: between 50 million and 200 million barrels
Very Small: 50 million barrels or less

Table A1.1 in Annex 1 contains a full listing of the size classification of the UK North Sea oilfields included in this analysis, and presents a number of diagrams that illustrate the size structure of both *The 1985 Group* and *The New Fields*. Diagram A1.1 in Annex 1. illustrates cumulative oil reserves versus field numbers in the UK North Sea sector, ranking fields according to the size definitions given above (i.e., the largest field is field number one, the next largest is field number two, and so on). The diagram reveals that although there are very few fields within the 'very large' category, they account for a disproportionately large share of total oil reserves in the UK North Sea sector. At the other extreme, there are a large number of 'very small' fields, but, in total, they contribute relatively little to the reserve base.

In terms of number,[6] the majority (46 out of a total of 54) of *The New Fields* are either 'small' or 'very small' (i.e., their reserves of oil are less than 200 million barrels). The fields within *The 1985 Group*, on the other hand, are much more evenly spread across the different size categories, although the majority of the fields in this category have oil reserves in excess of 200 million barrels. Indeed, eleven of the 31 fields in this group boast reserves of more than 400 million barrels, and are therefore classified as 'large' or 'very large'.

A comparison of the contribution made to total production by the different sizes of fields within *The 1985 Group* and *The New Fields* categories[7] reveals that, in the case of *The 1985 Group*, the vast majority of cumulative oil output since 1985 has been produced by 'large' or 'very large' fields. The 'very large' fields (which comprise the Beryl, Brent, Forties, Ninian and Piper fields) have been responsible for 46 per cent of total cumulative output since 1985, whilst the six 'large' fields in the group have contributed a further 30 per cent to total output. Between them, the 'small' and 'very small' fields have accounted for just 12 per cent of *The 1985 Group*'s cumulative production.

By contrast, 'small' and 'very small' fields have contributed a far higher share of the cumulative production of *The New Fields* since 1985, which stands at approximately 2.2 billion barrels. Indeed, over 1 billion barrels (or 53 per cent) of cumulative output of *The New Fields* has been produced by fields with oil reserves below 200 million barrels. Meanwhile, 'medium' fields have accounted for one-third (725 million barrels) of cumulative production,

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[6] See Diagram A1.2 in Annex 1.

[7] See Diagrams A1.3 and A1.4 in Annex 1.

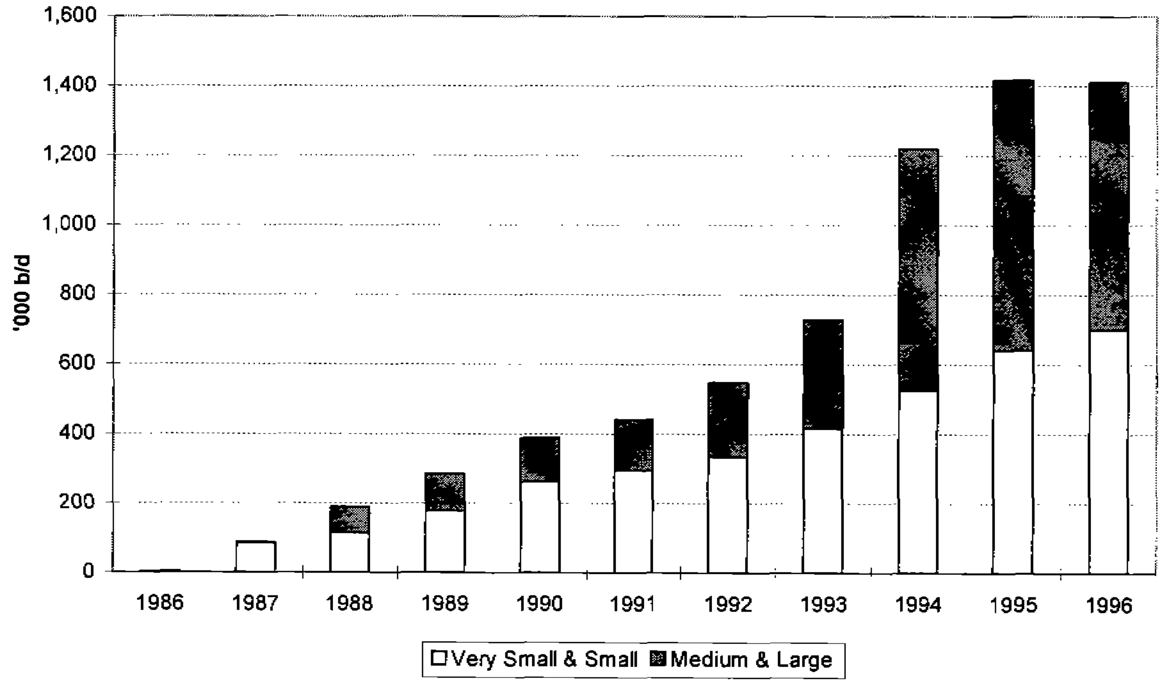
whilst 'large' fields have been responsible for the remaining 302 million barrels (or 14 per cent). There are no 'very large' fields within *The New Fields* category.

It is clear from this analysis that there is a sharp contrast in the size profiles of the two categories of oilfield. *The 1985 Group* is dominated by 'large' and 'very large' fields, with recoverable reserves of over 400 million barrels, whereas *The New Fields* group is characterized by much smaller fields. This should not be surprising. After all, given a portfolio of different sized fields, oil companies will tend to exploit the larger, more productive fields before they turn their attention towards the smaller, more marginal ones. Moreover, in terms of exploration, larger fields statistically have a higher chance of being discovered before smaller ones (although this is not *universally* the case). This helps to explain why larger fields play a more important role in *The 1985 Group* than in the new group. As explained in subsequent chapters of this study, in many cases, the decision to develop the smaller fields has only been made in the wake of recent advances in technology and changes to the UK fiscal regime, which have improved the economics of the exploitation of small fields.

Evolution in the Field Size Profile of UK North Sea Oil Production Since 1985

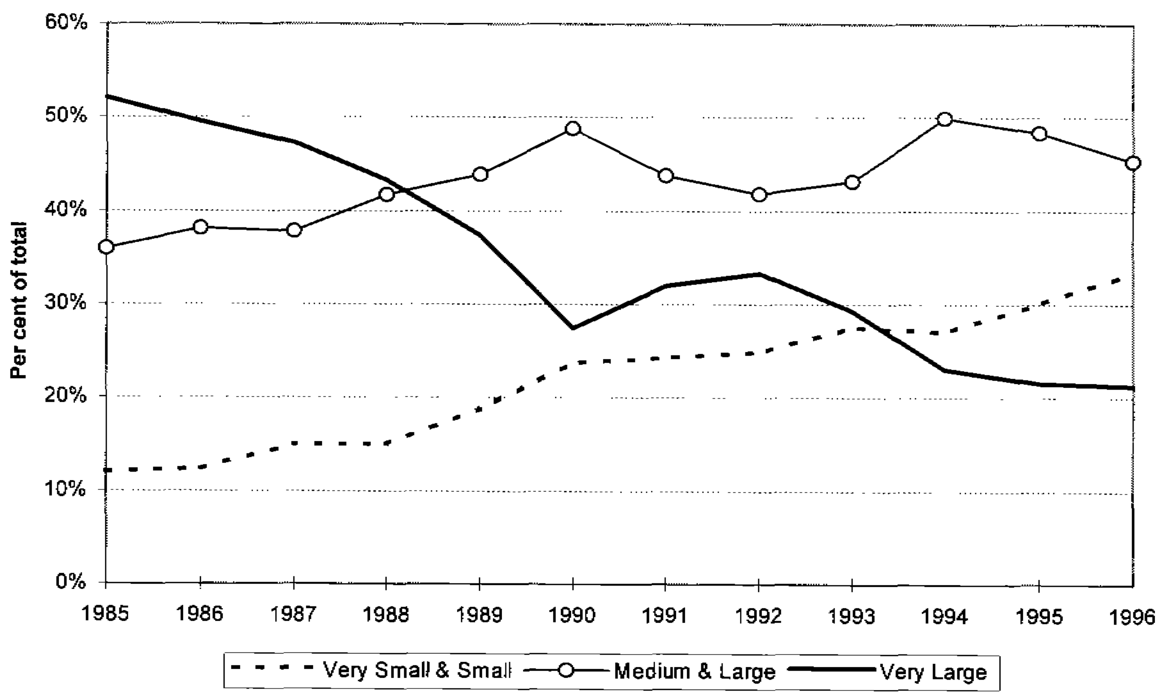
The importance of 'very small' and 'small' fields to the annual production profile of *The New Fields* is highlighted in Diagram 1.5. From 1986 until 1993, fields with recoverable reserves below 200 million barrels accounted for the bulk of annual output from *The New Fields*. However, with the emergence of fields such as Scott and Nelson, which fall within the 'large' category, the division in output in recent years has been more evenly shared between 'very small'/'small' fields, on the one hand, and 'medium'/'large' fields, on the other. This is in stark contrast to the annual production profile of *The 1985 Group* (not illustrated), where 'very small' and 'small fields' together have never accounted for much more than 10 per cent of annual production since 1985.

Diagram 1.5: *The New Fields* - Composition of Annual Output by Size of Field



By dropping the distinction between *The 1985 Group* and *The New Fields*, it is possible to examine how the changing composition of oilfields has affected the *overall* profile of annual UK North Sea oil output in terms of field size structure.

Diagram 1.6: Trend in Size Distribution of Annual UK North Sea Oil Output



As discussed above, due to the emergence of a new generation of fields in the North Sea, coupled with the downturn in output from the maturer (and generally larger) oil provinces, smaller fields have had an increasingly powerful influence over total UK North

Sea oil supply in recent years. The composition of production since 1985 by size of field is illustrated in Diagram 1.6. It is evident from this diagram that the influence of 'small' and 'very small' fields (i.e., those with recoverable reserves of less than 200 million barrels) has increased significantly over the period under examination. In 1985, such fields accounted for 12 per cent of annual UK North Sea production. However, over the course of the past ten years, the sharp increase in the number of new fields that have come on stream (many of which fall within the 'very small' and 'small' field size categories) has lifted this share to current levels of over 30 per cent of annual production. This increase has come largely at the expense of the 'very large' fields, namely Beryl, Brent, Forties, Ninian and Piper. The role played by these 'very large' fields, which dominated overall North Sea oil production at the beginning of the period under examination, is now much diminished. Indeed, their share of total production has slumped from 52 per cent in 1985 to little more than 20 per cent in 1995 and 1996. 'Large' and 'medium' fields, on the other hand, have successfully maintained their influence on overall oil supply from the North Sea: their share of total production has fluctuated within a range of 36 and 50 per cent over the past decade, with the underlying trend being upward. Their share has been underpinned in recent years by Nelson and Scott coming on stream.

The analysis contained in this chapter has described the trends that have taken place in UK North Sea oil production over the past decade or so. In Chapter 2, the key factors responsible for these trends in output are examined in detail.

SUMMARY POINTS

- After peaking at 2.6 million b/d in 1985, UK North Sea oil production entered a period of decline, sinking to 1.8 million b/d in 1991. However, since then, output has staged a strong recovery, reaching levels close to 2.5 million b/d in 1995 and 1996.
- Combined production from those oilfields that were already on stream in 1985 ('*The 1985 Group*') has dwindled over the past decade or so, reflecting the mature nature of these oil provinces. Many of the fields within this group reached peak output levels in the late 1970s/early 1980s, and are well into the downward slope of their production profiles. However, the rate of decline in output from these established fields has been relatively modest during the 1990s, at average annual rates of less than 10 per cent.
- Offsetting the decline in production from *The 1985 Group* has been rising output from a new generation of fields ('*The New Fields*') that have come on stream since 1985. Between 1986 and 1991, the new output from *The New Fields* was only able to *partially* compensate for the decline in oil production from *The 1985 Group*, with the result that the trend in overall UK North Sea oil output was downward. Since 1991, however, increasing output from *The New Fields* has been more than sufficient to offset declining supplies from the more established fields, contributing to the revival in total production.

- The number of oilfields operating in the UK sector of the North Sea has more than doubled since 1985, increasing from 31 to 75 in the first half of 1996.
- There is a marked contrast between the size structures of the oilfields in *The 1985 Group* and those comprising *The New Fields*. The latter is dominated by small or very small fields (which have recoverable oil reserves of 200 million barrels or less), while *The 1985 Group* is characterized by much larger fields.
- The emergence of the new generation of oilfields, coupled with the downturn in output from the maturer (and generally larger) ones, mean that smaller fields have had an increasingly powerful influence over total UK North Sea oil supply in recent years.

Chapter 2: Factors Influencing Changes in UK North Sea Oil Production

FACTORS AFFECTING THE DEVELOPMENT DECISION

What factors have influenced the changes in UK North Sea oil production over the past decade or so? It is clear from the analysis of Chapter 1 that the upturn in output in recent years has been underpinned by the increasing number of new fields coming on stream. Many of these new fields represent small developments which, in the past, would have been deemed uneconomic to develop. However, for a number of reasons, the economic viability of such ventures has been improved in recent years. In this chapter, the various factors that may have a bearing on the decision to develop oilfields are presented. Such factors include:

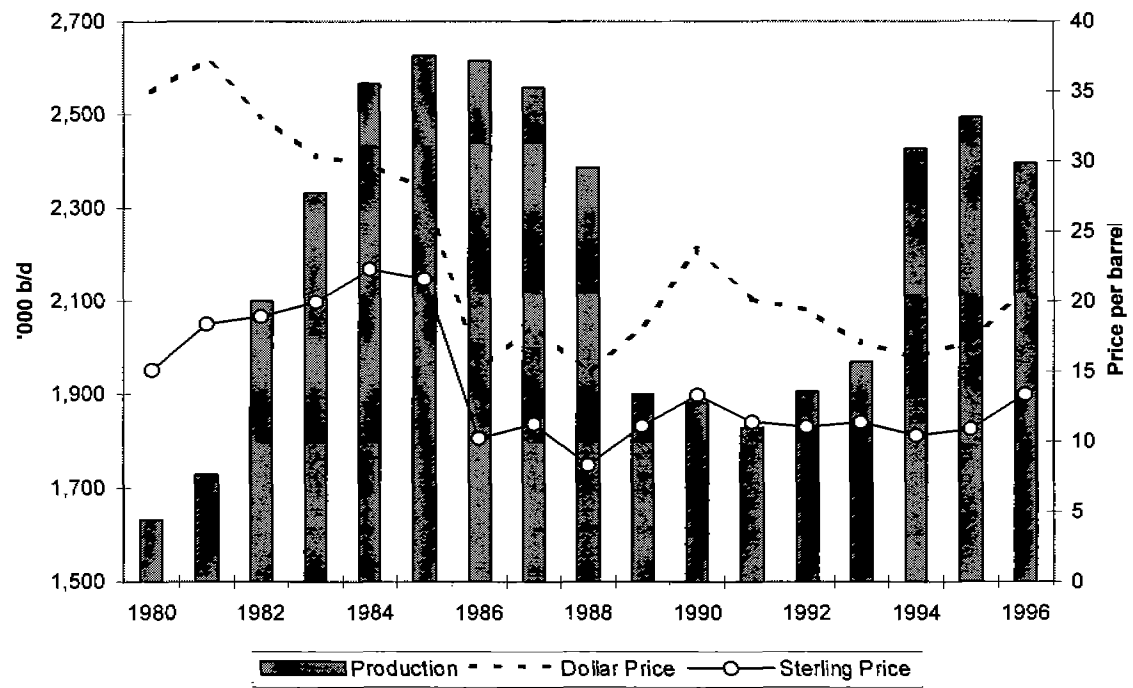
- the price of oil
- the UK fiscal regime
- new technology
- changes in the internal organization of the oil industry
- infrastructure
- gas considerations

The Price of Oil

Diagram 2.1 plots the relationship between real international oil prices and UK oil output from the North Sea since 1980. The oil price has been expressed in both sterling and US dollar terms. Although North Sea oil is traded in dollar terms, the bulk of costs are incurred in sterling terms. Meanwhile, whilst the sterling price of oil will be of interest to UK-based oil operators, international companies operating within the North Sea are more likely to focus on the dollar price. The difference in these two measures of price is most apparent in the early 1980s. The dollar oil price declined from 1981. However, the strengthening value of the dollar vis-à-vis the pound during the first half of the 1980s insulated the sterling price (and the companies operating in the UK North Sea). The sterling price in fact peaked in 1984, three years later than the dollar oil price maximum.

Diagram 2.1 reveals that there are clearly periods where high oil prices are associated with rising levels of oil production, albeit after a time lag. It could be argued, for example, that the strength of oil prices in the early 1980s precipitated the high levels of production achieved between 1984 and 1988. There are also times when the opposite situation has existed. The price collapse of 1986, for example, was followed two years later by the dramatic 20 per cent reduction in UK oil output. However, this apparently simple relationship between price and supply does not always hold true, notably in more recent years. Since 1991, oil prices have languished at relatively low levels, yet oil production has risen strongly over the course of the decade. This suggests that the relationship between the two is not a straightforward one.

Diagram 2.1: Relationship between UK North Sea Oil Production and the Oil Price



In his study of the relationship between the oil price and non-OPEC oil supplies, Adam Seymour (1990) highlights the insensitivity of UK oil supply to the international oil price by examining the muted impact that the oil price shocks of 1973 and 1979/80 had on UK North Sea oil production. He concludes that over 50 per cent of cumulative UKCS output between 1975 and 1988 was produced by oilfields that received Annex B approval *before* the 1973 price shock. Meanwhile, the development decisions taken before the price shock of 1979/80 accounted for over 90 per cent of total cumulative production (from 1975 to 1988), which suggests that the second price shock had relatively little impact on UKCS oil supplies.

Conventional economic theory would indicate that production at marginal short-run cost should respond quickly to price, within the constraints of existing capacity. One explanation for the insensitivity between oil prices and North Sea oil production is that, in the UK oil sector, capacity tends to be fully utilized,[1] and capacity is developed under *long-run* price and cost considerations. The analysis in this study is therefore best described as being concerned with the development of *capacity* within the UK North Sea oil sector.

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[1] except during periods of maintenance or in the event of an accident, such as the Piper Alpha disaster.

Typically, price increases stimulate exploration activity, which can be expected to yield a larger number of discoveries. However, whether or not the decision is taken to proceed with the development of these discoveries will depend on the oil companies' *expectations* of future prices and costs *over the entire life span of the project* (although current prices may be an indicator to this long-term view of prices). Once a field is developed, the ability of production from that field to respond to subsequent price movements is severely constrained by a number of factors, including:

- the legal obligations associated with the initial permit to develop (Annex B);
- the immediate cash flow needs of the operator;
- the need to recover the costs of exploration and development;
- the geological structure of the reservoir;
- the capacity of the available transportation.

As discussed in the following section, one of the most important factors behind the insensitivity of oil production to changes in the international oil price is the existence of the fiscal regime. The private sector will respond to a price of P minus T, where P is the oil price and T is the government tax take per barrel. Experience has shown that when international oil prices have been high, the UK government has responded by *increasing* the tax burden on oil companies. This helps to explain why the actual supply response to an increase in world oil prices may turn out to be negative. Similarly, an oil price fall, followed by a loosening of the fiscal regime, may be associated with an *expansion* of exploration and development activity.

The UK Fiscal Regime

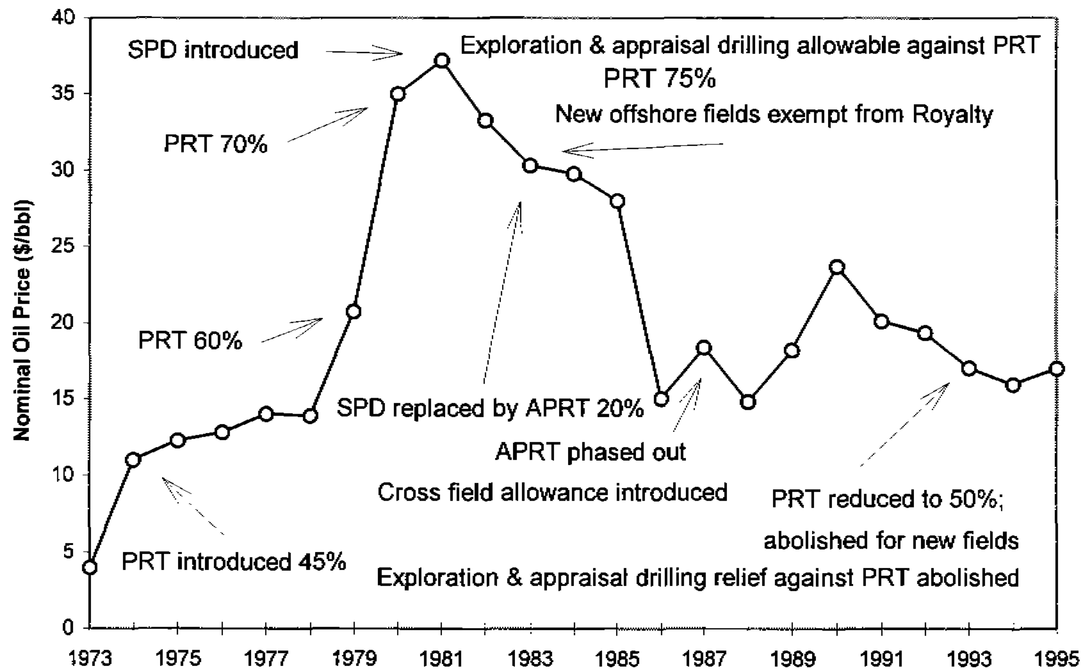
The existence of a fiscal regime can divorce the international price of oil from the price that is ultimately received by the producer (i.e., the price that will influence oil companies' production decisions). Oil producers will not receive the full benefit of high international oil prices if the government responds by increasing the tax burden on companies. Similarly, producers may be cushioned from low and falling oil prices if the government adopts a less restrictive fiscal regime. Fiscal measures can also exert a powerful influence on the development of new oilfields.

The UK government has had to develop a fiscal regime which, on the one hand, offers companies a sufficient financial incentive to explore for, and develop, the nation's oil and gas reserves, whilst also reaping benefits for the UK economy as a whole.

Traditionally, government revenues from North Sea oil production have been derived from three main sources:

- Royalty
- Petroleum Revenue Tax (PRT)
- Corporation Tax.

Diagram 2.2: Major Changes to the UK Oil Fiscal Regime



The main features and changes to the UK fiscal regime are discussed in the following paragraphs, with a particular emphasis on those elements that have had an important bearing on UK North Sea oil production over the past decade or so.

Diagram 2.2 illustrates the main changes to the UK oil taxation regime since 1973 in relation to the international oil price.[2] The impact of fiscal changes on activity in the North Sea can be assessed by Table 2.1 which shows the number of Annex B approvals granted on an annual basis since 1973 (which is a good proxy for the number of Annex B *applications* made in any one year).

[2] A chronology of the key fiscal changes since the introduction of the Oil Taxation Act of 1975 is also presented in Annex 2.1.

Table 2.1: Number of Annex B Approvals Granted, 1973-95

1973	3	1978	5	1983	4	1988	7	1993	3
1974	8	1979	1	1984	3	1989	7	1994	6
1975	1	1980	2	1985	5	1990	8	1995	1
1976	1	1981	0	1986	2	1991	9		
1977	0	1982	2	1987	3	1992	4		

Source: Wood Mackenzie

A Tightening of the UK Fiscal Regime (1979-82)

As Diagram 2.2 illustrates, the high oil prices of 1979 and the beginning of the 1980s resulted in a tightening of fiscal policy in a number of ways:

- A new tax — *Supplementary Petroleum Duty* (SPD) — was imposed on oil producers in 1981. It was charged at a rate of 20 per cent of gross revenues less an allowance of 1 million tonnes of oil per year. SPD was subsequently replaced by *Advanced Petroleum Revenue Tax* (APRT) at the beginning of 1983. Like SPD, APRT was applied to gross revenues less an allowance of 1 million tonnes per year. From 20 per cent during the first half of 1983, APRT was phased out on a sliding scale basis, and was finally abolished at the end of 1986, the year of the international oil price collapse.

- In recognition of the fact that no tax deduction is allowable with respect to interest, certain categories of capital expenditure qualify for an '*uplift*' allowance, which has the effect of reducing a field's PRT liability. Before 1 January 1979, relevant capital expenditure was uplifted by 75 per cent of the expenditure involved. However, after this date, the rate was reduced to 35 per cent.

- Fields are assigned an *oil allowance*, which is a gross production relief that reduces a field's liability to PRT. Until the end of 1978, this allowance stood at 500,000 long tons of oil for each six-month period up to a cumulative maximum of 10 million long tons. However, from 1979 onwards, this PRT-free allowance was curtailed sharply to 250,000 metric tonnes for each six-month period, with a cumulative maximum of 5 million tonnes.

- After remaining at 45 per cent since its inception in 1975, the *rate of PRT* was raised to 60 per cent in 1979, with further increases to 70 and 75 per cent in 1980 and 1983. Meanwhile, the *terms of payment* of PRT were made more stringent. 1980 saw the introduction of an element of pre-payment of the tax, whereby an amount of 15 per cent of the assessed liability for the previous but one period or 15 per cent of the payment on account of the previous period (whichever is the greater) is paid in advance. This amount is subsequently deducted when the actual PRT liability is calculated. From September 1983, payments were due in monthly instalments, effectively boosting the proportion of PRT paid in advance from 15 to 50 per cent. This is, in effect, an increase in the tax burden since, in the real world of cash flows, timing is money and advancing payment is equivalent to a one-time tax equivalent to the income that could have been earned on the amount of the tax.

Relaxation of the UK Fiscal Regime (post 1983)

After 1981, with world oil prices easing back from their 1979/80 highs, there were calls for a relaxation in the UK oil taxation system, with many oil industry participants arguing that the regime then in place was deterring a continuing exploration effort and the development of new fields. Indeed, as Table 2.1 reveals, there were a dearth of Annex B approvals around this time; in fact, *no* Annex B applications were granted in 1981, and there were only two during the year after. The UK government responded with a series of measures that made the tax regime less restrictive and improved the economics of developing new fields. For example, in the 1983 Finance Act, the following measures were introduced:

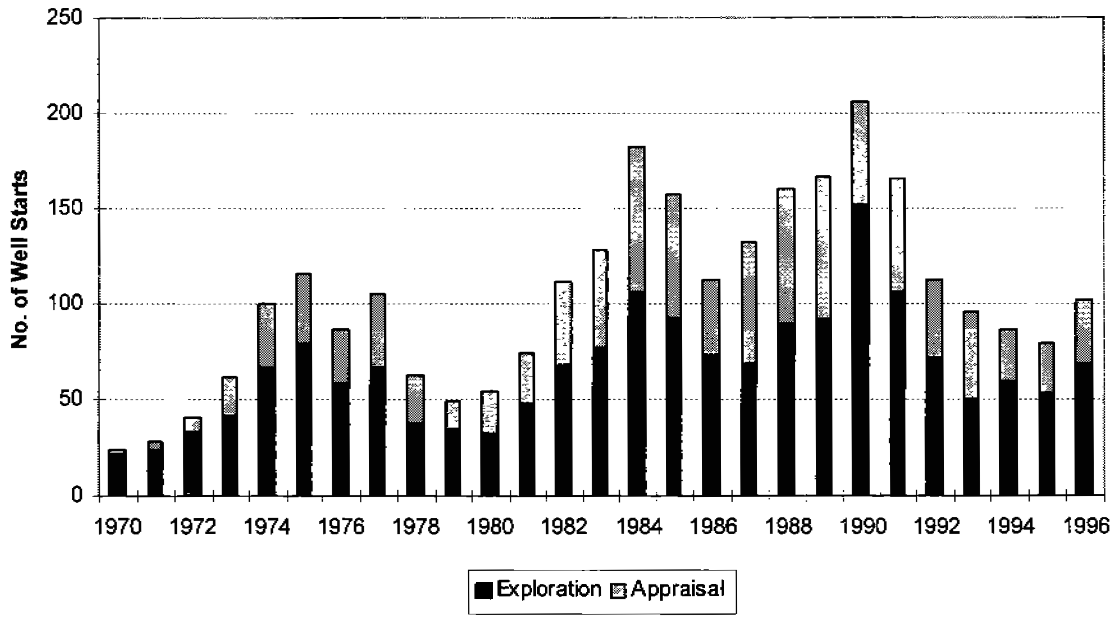
- Oilfields with Annex B approval after 1 April 1982 were *exempt from paying royalty.*
- The *oil allowance* of fields granted Annex B approval after 1 April 1982 was fixed at double the level that applies to fields approved before this date — i.e., 500,000 tonnes for each six-month period, up to a threshold of 10 million tonnes. This effectively meant that many 'new' fields had no PRT liability.
- Exploration and appraisal drilling were made available for immediate PRT relief.

While these various concessions had the desired effect of boosting activity in the North Sea (demonstrated by Diagram 2.3, which indicates an upturn in offshore exploration and appraisal drilling after 1983), the world price slump of 1986 prompted calls for a further relaxation of the fiscal regime. In the 1987 Finance Act, the government responded by introducing the *Cross Field Allowance* (CFA). For fields granted Annex B approval after April 1987, the CFA permitted up to 10 per cent of qualifying development expenditure to be offset against an operator's PRT liability on other fields.

A more significant relaxation of the UK fiscal regime was implemented in the Finance Act of 1993. Although the CFA was abolished and the allowable relief of exploration and appraisal expenditure against PRT was ended, the economics of developing new fields were boosted by the *abolition of PRT* for those fields granted Annex B approval after 15 March 1993. These new fields are therefore only subject to corporation tax, which has remained at

33 per cent since April 1991. Meanwhile, in the same Budget, the rate of PRT on existing fields was reduced from 75 to 50 per cent (its lowest level since 1978).

Diagram 2.3: UK Offshore Drilling Activity



Meanwhile, the development of marginal oilfields is also encouraged by other aspects of the UK fiscal regime, notably:

- *Safeguard Provisions:* The purpose of safeguard is to provide a form of PRT relief that will benefit less profitable fields, regardless of their size. It places a limitation on a field's PRT liability during the early stages of its life, remaining in place until the field has reached 'payback' (i.e., cumulative incomings exceed cumulative outgoings).

- *Ring-Fence:* There is a fiscal ring-fence around an activity (or set of activities) undertaken by a corporation when the profits and losses of this activity cannot be aggregated or set against profits or losses made by the corporation in other parts of its business in the computation of tax liabilities. The UK oil fiscal regime involves a ring-fence around every oilfield for PRT purposes (the so-called 'field-by-field' principle). Field-by-field fencing improves the economics of small fields because it gives them relief (via their own separate oil allowances and safeguard provisions) from PRT. Meanwhile, for the purposes of corporation tax, a ring-fence is placed around upstream activities in the UK (i.e., corporation tax is charged on a company basis and not on a field-by-field basis, which means it is possible to relieve losses arising in one field against profits from another).

The Columba 'D' Terrace is a good example of a small field whose commerciality has been *reduced* because it has *not* been granted its own ring-fence status. The Columba Terraces represent 'fault blocks' to the west and south west of the Ninian field. Although the Columba partners argued that Columba 'D' should be treated as a separate field from Ninian for tax purposes, this was rejected by the (then) Department of Energy in 1989, which argued that the Columba Terraces were part of the same structure as Ninian. Thus, Columba 'D' is included within the Ninian ring-fence. Since Ninian received Annex B approval well before April 1982, revenues from the sale of oil from Columba 'D' are subject to royalty. Moreover, the PRT liability of Columba is higher than other small developments because it does not have its own oil allowance; instead, Columba production must be 'absorbed' within Ninian's oil allowance. Because of this tax position, the development of Columba 'D', which was initially scheduled for 1992, was postponed. However, its economic viability was enhanced after the 1993 Finance Act, when the rate of PRT was reduced from 75 to 50 per cent.

A closer examination of the impact of changes to the fiscal regime on the decision to develop *The New Fields* is presented in Chapters 3 and 5 of this study.

The Impact of New Technology

There is little doubt that technological progress has had a far-reaching impact on oil production from the North Sea. The oil industry has been to the fore in embracing new technology and methods which have helped to reduce costs and maintain the profitability of current and future oilfield developments. As discussed in Chapter 1, a large number of the fields that have come on stream since 1985 are small developments, and are very marginal from an economic point of view. The volume of recoverable oil from such fields can be quite low (in some cases, estimated recoverable reserves may be as little as 5 million barrels or even less), resulting in a relatively short lifespan of the field. Complex geology and harsh operating conditions can further reduce the attractiveness of developing such fields. Conventional means of developing an oilfield — i.e., by installing a fixed production platform — are rarely cost effective under such circumstances. Instead, the development of small, marginal fields can often hinge on the ability to find alternative, *low cost* methods of exploitation. Fortunately, technological progress is providing such methods.

New technology is also boosting oil production from established fields. The development of improved oil recovery systems has resulted in a marked increase in the estimates of recoverable reserves of established fields, and has meant that production from such fields has been maintained at higher rates than earlier forecasts had suggested. A general increase in operating efficiency, combined with the upgrading of existing fields (by installing more modern equipment, redrilling wells, and increasing water or gas injection, for example) are also helping to maintain production at higher-than-expected levels. The extent of the increase in estimates of recoverable reserves of established fields is addressed in greater detail in Chapter 4.

As discussed in the paragraphs that follow, technology has had an impact at every stage of the upstream oil industry — from discovery to development, through to production. A comprehensive account of the various ways in which North Sea oil production has been affected by technological progress would span very many pages. Thus, for the purposes of this study, the discussion is confined to a summary of the key developments.

Exploration and Seismic Technology

This technology encompasses those methods that are designed to discover new fields and to improve the knowledge of existing developments (by finding new pockets of oil and gas and by monitoring the drainage of a reservoir, for example). There now exists a wide range of techniques to collect and analyse sub-surface information, although the basic principles of seismic surveying remain largely unchanged. Air guns towed by specially adapted ships transmit soundwaves which travel through the rocks below. As the soundwaves travel through the formations, energy is reflected back to the surface, which is sensed by detectors known as 'hydrophones'. In two dimensional (2D) seismic surveys — which were first used towards the end of the 1950s — only one line of detonations is used in each traverse, and the relationship between the traverses is not taken into account during imaging. The introduction of three dimensional (3D) seismic technology in the early 1980s represents a major advance in exploration technology. The main difference between a 2D and 3D seismic survey is that, in order to create the 3D effect, more airguns and streamers of hydrophones are used. These are positioned in lines parallel to each other, and the relationship between the traverses is pivotal to the imaging. The resulting seismic 'lines' give consecutive images of the formation that are close enough for the interpreters to compile 'cubes' of data which can be sliced vertically and horizontally. 3D seismic technology, with its associated enhanced information processing capability, has greatly improved the structural interpretation and faults and horizons, and has made an important contribution to the large number of 'satellite' field developments that have come on stream in the North Sea in recent years.

The main disadvantage of 3D seismic surveying is its high cost. According to BP Exploration Worldwide, the average cost of a 3D seismic survey in the North Sea is over £9,000 per square kilometre, which is equivalent to around $37,000 per square mile (*Horizon*, the magazine of BP Exploration Worldwide, March 1994). Meanwhile, the development of 3D seismic has been slowed by the technical difficulties associated with towing several lines of airguns and hydrophones, in addition to the large requirement for computing power to interpret the results. Until quite recently, it took over a year between the first shot of a survey being fired to the completion of the first interpretation. However, the emergence of small, yet powerful computers, coupled with the ability to fix accurately the position of the survey vessel, mean that data processing can now take place offshore, thereby sharply reducing the time delay between the collection of the seismic information and its analysis.

Another factor that has enhanced the attractiveness of 3D seismic surveying is the rising cost of drilling wells, which has provided an incentive to minimize the risk of drilling dry holes. Meanwhile, oil producers in the North Sea are increasingly focusing their exploration efforts in more complex environments, whilst trying to maximize the amount of oil produced from existing fields. The more information there is on the rock formations, the more accurate is the drilling. This is particularly important in the design of the trajectories of horizontal wells. An industry rule-of-thumb is that in exploration drilling, there is approximately one success in every five wells drilled on the basis of 2D seismic survey data. This rises to one in two using a 3D survey (*Horizon*, March 1994). Meanwhile, seismic technology can also prove to be a valuable asset for established fields since production drilling is usually an on-going activity and the location of the drills is important.

To improve the proportion of the total oil-in-place that is recovered, four dimensional (4D) seismic surveying is now emerging as the latest weapon in the geologist's armoury. It is used predominantly to improve the understanding of fields that are already producing oil or gas, and represents a time lapse method, where 3D seismic surveys are repeated at regular intervals over time in the same place. According to BP, the use of 3D seismic surveys on the BP/Shell Foinhaven development to the west of Shetland is expected to boost recovery of the oil-in-place to between 40 and 50 per cent. However, with 4D techniques, this percentage could rise to between 65 and 75 per cent (*Oil and Gas Journal*, 20 May 1996).

4D technology enables the geologist to monitor the reservoir as it is drained, providing information about the migration of water, changes in gas:oil ratios and variations in pressures. Armed with such knowledge, engineers are better able to optimize the production profile of a reservoir. They can also establish whether secondary/artificial methods of recovery are necessary and, if so, where and when water injection or other types of wells should be drilled. 4D surveys also identify pockets of oil and gas which are not being produced because they are not connected to the main reservoir, but which could be exploited by the drilling of separate wells.

New Production and Drilling Technology

The spread of technological progress has revolutionized production and drilling methods in many ways. The major developments are highlighted under a series of sub-headings: subsea completions, new platform design, drilling technology and floating production, storage and offloading vessels (FPSOs)

Subsea Completions

Traditionally, the wellheads of offshore oil and gas wells have been *above* the surface of the sea, either on a fixed platform or (less commonly) a floating production vessel. The wellhead is connected to the well on the seabed by a vertical pipeline known as a 'riser'. However, in recent years, subsea completions — which involve the installation of the wellhead at the seabed — have become increasingly popular. Indeed, around 40 per cent of the fields that have come on stream since 1985 are (or have been) exploited by means of subsea technology. In many cases, several wellheads are completed below the surface of the sea and 'tied back' to a nearby platform. In other words, small fields in the proximity of established fields with available infrastructure can be integrated into the parent processing platforms and pipeline system as 'satellite' fields. A typical subsea assembly is connected to a series of 'umbilicals' which carry control signals and derive power supplies from a nearby platform. Production from the subsea well is carried through a flowline or pipeline to the platform.

The major advantage of a subsea completion is that it is much cheaper than the construction and operation of a conventional platform, which means that the use of subsea technology can boost the economic viability of marginal developments. This point is highlighted in the analysis presented in Chapter 4 of this study. Subsea equipment is becoming smaller and lighter, and costs are falling. In 1990, the estimated average cost of a subsea installation was £20 million ($28 million) per well. In 1995, this figure was reduced to just £6.5 million (around $10 million) (Upton, 1996).

Another advantage that subsea systems have over conventional platforms is their safety. With a subsea installation, there is no riser that is prone to impact or corrosion, and, because they are unmanned, there is no risk of injury if anything goes wrong. However, on the negative side, subsea completions are often difficult to maintain and have to be operated from a distance, which requires reliable instrumentation and remote control technology.

In addition to their cheapness, subsea systems offer benefits for ageing conventional platforms. Faced with the prospect of decommissioning a platform — which has become a highly contentious issue in recent years — operators are continually searching for potential 'tie-backs' to satellite fields in order to extend the economic life of its facilities. Subsea completions also open up new possibilities for developing deep water wells, with the industry now able to operate in depths of up to 2,000 metres of water. However, water depth remains the main limiting factor to the greater use of subsea technology, with installation and operating costs increasing rapidly as the water depth increases.

New Platform Design and Maintenance

Where subsea completion is not feasible or desirable, it may still be necessary to build a new production platform, and technological advances in this area have spawned a new generation of structures, which are smaller, lighter and cheaper than those constructed in the 1970s and early 1980s. Meanwhile, improved maintenance techniques are helping to extend the productive life of platforms. Traditional forms of maintenance use a combination of two methods: (i) regular inspection of components to detect potential failures and replace them, and (ii) anticipation of the expected life of a component, replacing it automatically as its expected life expires, regardless of the condition it is in. Projects have been developed that attempt to collate and optimize the various aspects of maintenance planning. Databases of component reliability are being compiled and the effects of stress and deterioration are modelled. This information can be used to optimize the scheduling of maintenance, thereby minimizing downtime and the use of resources.

Drilling Technology

New drilling techniques have played an important role in accessing new reserves in the North Sea. A particularly effective way of reducing the development costs of an oilfield is to produce from fewer wells, which is made possible by horizontal drilling. Although horizontal wells cost around 50 per cent more than vertical wells to drill, they can produce up to five times as much fluid. This is because there is far greater contact with the producing zone, compared with conventional vertical wells, which results in a more efficient drainage of the reservoir. Horizontal drilling can therefore greatly improve the economics of small, marginal developments.

The drilling of extended reach and deviated wells represents another breakthrough. Often drilled from an existing platform, such wells can tap parts of a field or outlying structures at a much lower cost than other options (such as installing a new platform or subsea system, or drilling from a mobile rig). This has the effect of maximizing the area that any one platform can tap. Progress in this area is extending both the range of wells and the precision with which they can be 'steered' into the optimum position of the reservoir. Satellite fields such as Columba 'D', Leven and Medwin have been developed with the use of extended and/or deviated wells drilled from nearby platforms.

Other forms of drilling technology include improvements in the design of the 'drill pipe'. Traditionally, drilling has involved the use of rigid tube, produced and handled in ten metre lengths, and screwed together to make up the drill string. An alternative is the use of coiled tubing, whereby the rigid pipes are replaced by flexible tubes, which are easier to handle, and require smaller, lighter and cheaper drilling rigs. Coiled tubing drilling is also much safer than conventional techniques: there is no need to connect and disconnect lengths of drill pipe, which results in the minimum exposure of personnel on the drill floor to the risks of handling and spinning heavy items.

Until quite recently, the use of coiled tubing has been hampered by the limited size of the tube that could be manufactured. However, this situation has changed during the 1990s as the available size of coiled tubing has got larger, and its increased use has coincided with new interest in drilling narrower (and cheaper) wells.

Floating Production, Storage and Offloading Vessels (FPSOs)

These vessels replace most, if not all, of the activities that are normally performed by a fixed production platform. They are becoming an increasingly common feature in the North Sea, particularly in the development plans of smaller fields and reservoirs that are remote from existing infrastructure. The advantages of using a FPSO vessel are largely economic. The capital costs involved are often much less than those for a fixed platform, and a large number of the FPSO vessels currently in use are being provided by contractors on a lease basis, either on a specific day rate or according to the level of production. Moreover, the development lag (i.e., the time delay before oil revenues are earned from a field) is shortened drastically when FPSOs are employed. Another attraction of using FPSOs is that, with an average life of 20 years or so, they can be used to exploit a small field over a period of five to ten years, and then move on to another field at minimal cost and without the need for potentially expensive abandonment and removal of a fixed installation.

One of the most modern examples of FPSO vessels currently in use in the North Sea is BP's *Seillean* vessel. This represents a tanker-based single well oil production system (SWOPS). The *Seillean* has a storage capacity of 300,000 barrels, and was originally used to exploit the Cyrus field from April 1990 to March 1992, before moving to its current location above the Donan field. Elsewhere, small fields such as Angus, Blenheim, Crawford, Gryphon and Hudson have also been exploited using floating production systems.

Changes in the Internal Organization of the Oil Industry

Another important source of cost reduction within the oil industry stems from changes in its own internal organization. The move towards cost reduction within the industry was given extra impetus by the international oil price collapse of the mid 1980s. While many companies have sought to make cost reductions individually, a joint, industry-wide, approach to the introduction of cost saving measures has also been adopted in the form of the Cost Reduction Initiative for the New Era (CRINE). Meanwhile, the evolution of the relationship between operators and their suppliers is yielding its own set of cost economies. These issues are addressed in this section.

Cost Reduction Initiative for the New Era (CRINE)

Because it was felt that a joint approach to cost reduction would be more effective than individual efforts, CRINE was set up in 1993 by a joint working group from the oil industry and the UK government. CRINE is not a standing bureaucracy; instead, a very small secretariat coordinates the work of several committees and working groups. The committee members are drawn largely from the industry, although the initiative is jointly funded by the industry and the government.

Much of CRINE's work has focused on the simplification of processes that oil companies have made more complicated over the years. One of the goals of CRINE is to encourage the standardization of equipment and working practices. The standardization of designs leads to a number of economies, including:

- reduced design time and cost;
- reduced manufacture time and cost;
- the possibility of maintaining a 'stock' of some items, thereby shortening development times; and
- better manufacturing methods by repeat production.

Areas in which common working practices are being considered include structural steel, process and utility pipework, coatings, insulation and the installation of electrical equipment and instrumentation.

Another target of CRINE is to standardize quality assurance processes into new generic prequalification systems, which all operators would accept, thereby removing the need for each operator to repeat the process. This has the advantage of relieving oil companies of much of the paperwork, without sacrificing attention to quality and safety requirements.

The Relationship between Operators and their Suppliers

The first generation of projects in the North Sea encountered a number of problems that encouraged operators to deploy very large project teams to organize, plan, supervise and monitor every aspect of future developments. Although design and construction contractors *were* employed, there was nonetheless a very heavy input from the oil company. The operator was responsible for selecting and managing every contractor who worked on a project, and the operator would also tend to specify the exact technology that was required. Success in second generation projects suggested that this approach was effective in ensuring that the work was completed on schedule, within budget and to the required quality. However, the built-in costs of this approach were high, since they included the cost of the operators' team, as well as the staff in the various contractors' offices to interact with the operators' team.

As the industry has matured, and all parties have increased their experience and competence, the need for such large teams has been diminished. Now, rather than act simply as an employer of specialist firms, operators are trying increasingly to develop concepts of 'partnership', in which the expertise of the specialist contractor is used to the full. This involves changes in the working relationship between operators and suppliers, which is intended to provide a better flow of ideas, and to turn each project into a partnership where the participants share common goals, and pool their resources to achieve them. Under the terms of the new operator/contractor relationship, outside contractors are performing a wide variety of functions that in the past would have been undertaken by the operators.

Under this new style of agreements, contractors are often paid according to their performance, rather than the traditional basis of a fixed price or a fixed price plus escalators related to external circumstances. The advantage of the new payment arrangement is that contractors have an incentive to do the job as quickly and as efficiently as possible. However, the down side is that the contractor has to bear some of the risk associated with the venture. In addition to performance risk, for example, the contractor may also have to bear the burden of commercial risk if his return is partly related to the commercial success of the project.

The development of BP's Andrew field, which began operations during the second half of 1996, provides a good example of the changing relationship between the operator of the field and the contractors engaged to design, build and install its facilities. In a departure from conventional project practice, the contractors (who formed an alliance) were asked to take responsibility for a percentage share of any cost savings or overruns that Andrew might have potentially produced. The arrangement meant that if Andrew's facilities were delivered for less than the agreed 'target' sum of £373 million, the contractors and BP would split the savings in the ratio 54 to 46 per cent. On the down side, if cost overruns occurred, the joint exposure was capped at £50 million, of which the contractors were liable for £27 million (i.e., 54 per cent of £50 million), while BP and its partners would be at risk for the remaining £23 million. Beyond this figure, any additional overrun would have been carried by the operators. The financial incentive provided by this 'gainshare' agreement produced the desired result, and a large number of cost savings were realized. In the case of the fabrication cost of the platform jacket, template and piles, for example, the final cost was around £9 million below the sanctioned estimate, a saving of close to 30 per cent (Knott, 1996).

In a developed alliance relationship such as the one described above, the supplier and purchaser (i.e., operator) may agree to collaborate to improve standards and design. Such a relationship may involve an exchange of personnel, and the resulting technology may become joint property. An even more elaborate relationship involves the operator dealing with several suppliers, who work jointly to solve particular problems. Provided that the suppliers are complementary and not competitive, they can jointly achieve a degree of synergy that might have been beyond reach under the traditional one-to-one relationship between operator and supplier. A similar arrangement is where the operator delegates much of the management of an operation to a 'head contractor' who, in turn, manages some or all of the other suppliers. The advantage to the operator is simplicity. If the system works as intended, the contractor only has one set of bills to pay and one relationship to manage.

While enthusiasts suggest that such partnerships result in significant efficiency improvements, the approach has its sceptics, particularly among the supplying and service companies. Cynics argue that the partnerships could be used by the oil companies to push down prices and shift some of the risk to others.

Infrastructure

The existence or absence of a transportation infrastructure can have an important bearing on the decision to develop an oilfield. The decision to build a pipeline and a terminal, once taken, provides a major economic incentive to the future exploration and development of a province. Smaller discoveries that might have been left undeveloped can become commercial prospects through the existence of a nearby pipeline. Indeed, all the new fields that have come on stream since 1985 make use of a long-established pipeline system. Much of the investment in this infrastructure took place during the early 1980s, at a time of strong oil prices and when oil companies' coffers were bulging. Furthermore, the economics of the first generation of oilfields, such as Brent and Forties, were favourable enough to justify fully the cost of building dedicated new pipelines to these fields.

The economics of many of the new generation of oilfields, on the other hand, are *not* attractive enough to warrant the construction of a dedicated pipeline to shore. However, the proximity of such fields to existing pipelines means they are able to benefit from the investments made in earlier years since it is a relatively cheap affair to connect a tie-in spurline to an existing pipeline. By passing the Petroleum and Submarine Pipeline Act of 1975, the government was granted wide powers — although these have yet to be exercised — to compel owners of pipes to accept production from third parties, in return for a tariff, thereby helping to encourage the development of marginal discoveries located close to existing infrastructure.

There are currently seven major oil and gas pipelines serving the majority of the fields in the UK central and northern North Sea. With the exception of the Beatrice oil and Miller gas pipelines, all the systems transport volumes from more than one field. Pipeline capacity constraints are rarely a problem since most of the larger fields (which account for the bulk of the throughput of existing pipelines) have already passed their production peaks, freeing up capacity for other third-party users, who often only make modest contributions to pipeline throughput. Indeed, the majority of *The New Fields* have peak production levels of below 50,000 b/d, and therefore make only modest demands on pipeline capacity.

Table 2.2 highlights the spare capacity available for use by *The New Fields* of each of the four major UK pipeline systems in the North Sea — Forties, Brent, Ninian and Flotta — since 1985. Spare capacity is defined as the difference between total pipeline capacity and throughput by *The 1985 Group* of fields, and there is little evidence that pipeline capacity has been a constraint to the development of new fields during the 1990s. In the mid/late 1980s, however, spare capacity was relatively tight at the Forties pipeline system, although this tightness did not last long. The Forties pipeline was upgraded at the beginning of the 1990s, boosting its capacity from 630,000 b/d to 1,000,000 b/d, whilst falling production from the Forties field also freed up capacity in the pipeline.

Table 2.2: Spare Capacity[1] within Major UK North Sea Pipeline Systems for Use by *The New Fields* ('000 b/d)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Forties [2]	239	279	292	328	414	431	832	840	871	869	884	879
Brent	544	531	542	578	732	895	767	699	768	802	812	807
Ninian	767	792	840	858	872	882	912	932	933	935	943	951
Flotta	290	310	320	459	555	520	509	514	459	434	431	451
Total	**1,840**	**1,912**	**1,994**	**2,223**	**2,573**	**2,728**	**3,020**	**2,985**	**3,031**	**3,040**	**3,070**	**3,088**

Notes: [1] Spare capacity is defined as the difference between total pipeline capacity and throughput by *The 1985 Group* of fields.

[2] The capacity of the Forties pipeline was increased from 630,000 to 1,000,000 b/d in 1991.

One of the most notable examples of the development of an oilfield being dependent on infrastructure considerations is Miller, although it was the transportation of the field's *gas*, rather than oil, supplies that was at issue. The development of Miller could not have gone ahead until the choice of evacuation of the associated gas had been resolved. The whole question was inexorably linked to the wider problem of gas transportation from the central North Sea as a whole. The UK government did not want to see a proliferation of unnecessary pipelines. However, it was successfully argued that, unless a dedicated pipeline was constructed, the development of Miller would have been retarded, and the government eventually relented. The Miller field came on stream in 1992, the year when the Miller gas line came into operation.

Gas Considerations

The example above highlights that the decision to develop the field can sometimes rest primarily with considerations related to its gas, rather than oil, reserves. Of the new fields that have come on stream since 1985, Brae East, Bruce, Amethyst, Everest, Lomond and Miller fields can be identified as those that have been developed primarily for their gas reserves (but which also have associated liquids production). In the case of the Bruce field, the main factor affecting the timing of the development was the negotiation of a suitable gas sales contract. On 31 August 1989, BP (the operator of the Bruce field) announced that British Gas had contracted to purchase 90 per cent of the field's gas reserves, with the remaining 10 per cent being sold in March 1990 to Corby Power Ltd. Having secured these customers for its gas, the Bruce field eventually came on stream in May 1993.

Interaction between the Various Factors

A key objective of this study is to assess the relative contributions made by the factors discussed in this chapter to the upturn in UK North Sea oil production in the 1990s. This task is made complicated by the large number of *interactions* between the various factors that determine whether the development of a new oilfield should proceed.

As discussed above, the price that is ultimately received by the oil producer will reflect both the international oil price and the fiscal regime in place. These two variables are inter-connected: historically, the UK government has tended to increase the tax burden during periods of high oil prices, whilst relaxing the fiscal regime when oil prices have fallen back.

Furthermore, there is a link between the fiscal regime and the adoption of new technology by producers. For instance, before 1979, when the fiscal regime was extremely generous, tax could be paid well in arrears, and a great deal of capital costs could be offset against tax since uplift was set at a high rate. As a result, there was little incentive to reduce capital costs, which dampened the enthusiasm for adopting capital-saving new technology. However, this changed when the regime was made more restrictive during the period of strong oil prices in the early 1980s. In addition to the imposition of new forms of taxation (SPD, replaced later by APRT), the payment of tax was speeded up and uplift was reduced. This provided more of an incentive to reduce capital costs.

It is argued that the oil price collapse of 1986 was a blessing in disguise for the North Sea oil sector since it forced oil companies to become more cost effective in order to maintain their margins. Meanwhile, low oil prices are also often cited as the primary motive behind the cost-saving measures arising from changes to the internal structure of the industry (such as those associated with CRINE). However, it can also be argued that *high* oil prices have been conducive to the adoption of cost-saving new technology, by providing oil companies with the the funds to research and develop new methods of production.

THE SIGNIFICANCE OF THE TIMING OF NEW DISCOVERIES

Clearly, the decision about whether or not to proceed with the development of an oilfield can only be made once that field has been discovered. The vast majority of *The 1985 Group* of fields had been discovered during the first half of the 1970s. In the case of *The New Fields*, however, the dates of discovery are much more diverse, ranging from 1969 (in the case of Arbroath) to 1991 (Fife). By 1985 (the starting point for much of the analysis in this study), there was a 'stock' of fields that had been discovered, but had not been developed, chiefly because, at the time, it was not economic to do so. As a result of some of the factors discussed in this chapter, the economic viability of these fields improved after 1985, which precipitated the decision to bring them on stream. However, a number of *The New Fields* had *not* been discovered by 1985. These are listed in Table 2.3.

Table 2.3: *The New Fields* Discovered after 1985

Name of Field	Date of Discovery	Name of Field	Date of Discovery
Beinn	July 1987	Harding	January 1988
Blenheim	November 1990	Hudson	July 1987
Donan	May 1987	Linnhe	August 1988
Fife	April 1991	Moira	May 1988
Gannet D	April 1987	Nelson	March 1988
Gryphon	July 1987	Ness	May 1986
Hamish	January 1988	Saltire	January 1988

Source: UK Department of Trade and Industry, *The Brown Book*

By itself, the 'late' (i.e., post-1985) discovery of a field is not a factor that explains the decision to *develop* a field. The development decision will depend on the economic viability of that field. As the analysis contained in Chapters 3, 4 and 5 of this study suggests, even if they had been discovered earlier, many of the fields listed in Table 2.3 would not have come on stream were it not for the relaxation in the fiscal regime and/or cost-saving new technology. However, late discovery can affect the *timing* of certain field developments, and this can be important when examining the upturn in UK North Sea oil production during the 1990s. Most of the recent discoveries listed in Table 2.3 represent small developments, which have had only a modest influence on overall UK North Sea output in recent years. The notable exception is *Enterprise Oil's* Nelson field, which has emerged as one of the most productive UK oilfields, and has been very influential in the overall expansion in UK North Sea oil output. (Indeed, average production from Nelson in 1996 was 166,000 b/d, bettered only by supplies from the Brent field.) Nelson came on stream in 1994, having been discovered as recently as 1988. The analysis contained in Chapter 5 of this study indicates that the Nelson field would have been economically viable *even in the absence* of the relaxation of the UK fiscal regime and cost-saving new technology. This suggests that the field would have come on stream much sooner if it had been discovered earlier.

Of course, the timing of a field's discovery will depend, to a large extent, on the allocation of blocks to licensing. Licensing policy is a means by which the UK government controls the rate and location of North Sea oil exploration and exploitation. Licences are issued in 'rounds', when pre-selected blocks are offered to oil companies. At the time of writing, there have been seventeen offshore licensing rounds since the first in 1964. Fields cannot be discovered until licences for the relevant blocks have been granted. Annex 2.2 lists the oilfields discovered in the blocks issued during the first ten licensing rounds (which includes all the fields in our analysis). The information contained in this Annex reveals that whilst fields such as Harding and Hamish were discovered soon after their blocks were licensed, a large number of fields discovered after 1985 were found many years after the licence for the blocks in which they are 'housed' had been issued. Significantly, the licences for Nelson's acreage were among some of the first to be released, in the second licensing round, which took place in 1965. Its discovery was more than twenty years later. Hence, the discovery of this productive field can hardly be considered to have been delayed by the licensing system. Instead, exploration drilling produced disappointing results for many years until Enterprise Oil gained 100 per cent in the Block 22/11 in December 1987, by acquiring the interests of partners Conoco (25 per cent), Chevron (30 per cent) and BP (15 per cent). The Nelson discovery well was spudded soon after, in February 1988.

To a certain extent, the date of discovery of an oilfield will also be dependent on advances in exploration technology and on the fiscal regime. In the Finance Act of 1983, for example, exploration and appraisal drilling was encouraged by the decision to allow PRT relief on the costs associated with these activities (although this arrangement was subsequently abolished in the 1993 Finance Act). Meanwhile, on the technology front, new discoveries are being fostered by advances in seismic surveying techniques.

Having identified the key factors that help to explain the trends in UK North Sea oil production over the past decade or so, the following chapters of this study present *a modelling exercise*, which attempts to gauge the relative importance of factors involved, focusing, in particular, on the roles of the fiscal regime and new technology.

SUMMARY POINTS

- Since 1991, UK North Sea oil production has been chiefly insensitive to the international oil prices. While prices have languished at relatively low levels, oil output has risen strongly.

- Part of the reason for this insensitivity is the existence of the fiscal regime, which divorces the price that is actually received by producers from the international oil price.

- A number of features and changes to the UK fiscal regime have helped to improve development prospects of marginal North Sea oilfields in recent years. These include:

- the abolition of payment of royalty for those fields with Annex B approval after April 1982;
- the doubling of the oil allowance for PRT purposes for the same group of fields as above;
- the lowering of the rate of PRT in mid-1993 from 75 to 50 per cent for existing fields and abolishing PRT entirely for fields with Annex B approval after 15 March 1993;
- the existence of safeguard provisions, which are designed to limit the PRT liability of marginal developments.

■ Advances in new technology have helped to boost the output of established oilfields and, by reducing costs, have encouraged the development of marginal fields. Among the most notable areas of technological progress have been: 3D and (more recently) 4D seismic surveys; subsea production systems; the drilling of horizontal and deviated wells; and the deployment of floating, production, storage and offloading (FPSO) vessels.

■ Cost savings have also arisen from within the internal organization of the oil industry, either through co-operative efforts, such as CRINE, or through the changing relationship between operators and their suppliers.

■ The availability of existing pipeline infrastructure has also played an important role in the decision to develop marginal fields.

■ There are a large number of interactions between the various factors that influence whether the development of a new oilfield should go ahead.

■ The timing of discoveries has also had an important bearing on the profile of UK North Sea production in recent years. The Nelson development, for instance, has emerged as one of the most productive fields in the North Sea, yet was discovered as recently as 1988.

Chapter 3: The Impact of the Fiscal Regime

In the previous chapter, the various factors that have had an impact on UK North Sea oil production were discussed. In this chapter, and in Chapters 4 and 5, the analysis focuses on what are generally believed to be the two most important of these factors: the fiscal regime and new technology. It was concluded in Chapter 1 that the primary reason why UK North Sea oil production has recovered so strongly in the 1990s is the emergence of a large number of new fields; it therefore seems sensible to examine the fiscal regime and new technology in the context of influencing the decision to develop these new fields.

The analysis will be built up in three stages:

- In this chapter, the concept and role of a target internal rate of return in the decision to proceed with the development of a field will be explained. Furthermore, the cash flow model that underpins the analysis of the impact of fiscal reform and new technology will be introduced. This model will then be used to gauge the impact of fiscal relaxation on the economic viability of *The New Fields* under existing technology (cost) conditions. In other words, accepting that new technology has enabled cost-savings in the development of new oilfields, the model estimates how the economics of these new ventures have been influenced by fiscal changes in recent years. The analysis in the chapter therefore attempts to answer the question: if the fiscal relaxations of 1983 and 1993 had not taken place, but operators still had access to actual production techniques, which of *The New Fields* would not have been developed?

- Chapter 4 considers the new technology side of the equation. The cash flow model is used to assess the extent by which the commercial viability of *The New Fields* has been improved by the impact of cost-saving new technology. Assuming the existing fiscal arrangements remain in place, which of *The New Fields* would not have been developed in the absence of cost-saving new technology? Consideration is also given in this chapter to the impact of new technology on *The 1985 Group* of fields.

- Chapter 5 pulls together the results of the analysis contained in Chapters 3 and 4 to provide a summary of those fields whose development has been apparently triggered by fiscal relaxation, and those where cost-saving new technology has been the pivotal factor. Fields that would likely have been developed even in the absence of both fiscal reform and new technology are also identified in this chapter. Armed with this knowledge, it is possible to simulate how the profile of UK North Sea oil production since 1985 would have looked in the absence of either, or both, new technology and changes to the fiscal regime.

INTERNAL RATE OF RETURN

Typically, the decision on whether or not to proceed with the development of a field will depend on the operator's expectation of revenues vis-à-vis costs. Future cash flows can be spread over very many years. Hence, when projects are appraised, the value of future payments is *discounted* against an assumed interest rate (the discount rate) to calculate a *net present value* (NPV) of the payment. From a discounted cash flow, an internal rate of return (IRR) can be calculated, representing the discount rate at which the NPV of the project is zero. The IRR of a project can then be compared with the rate of return that the investor feels he will get if his financial capital is used elsewhere (for example, to fund another project, or is put in an interest-bearing account).

For the purposes of the analysis in this study, *it is assumed that fields are developed if their calculated IRR exceeds a certain target level.*[1] Because there exists no systematic information about the revenue and cost assumptions used by operators *at the time the decision was taken* to develop individual oilfields, the IRRs calculated in this study are based on Wood Mackenzie's cost and revenue estimates and forecasts that were published in June 1996 — although it should be recognized that these may differ markedly from those actually used by operators during the development process of some fields. The tax burden of fields is estimated using the taxation model described in Annex 3.1.

The target IRR level which will trigger the development of a field will inevitably vary between operators and projects, and over time. For example, large multinational oil companies with strong balance sheets may be prepared to accept a lower rate of return from a project than a small independent company, which has a more vulnerable portfolio and is looking purely for profit. Meanwhile, it could be argued that target IRRs during the 1990s may be lower than those in the 1970s because inflation and interest rates have been lower, and technical risks reduced.

For much of the analysis contained in this study, a target IRR of 15 per cent is assumed (although, in Chapter 6, the sensitivity of the results to a *range* of different IRRs is examined). The choice of 15 per cent is considered typical by the industry. It is also the percentage used in the safeguard provision of the PRT calculation (i.e., during the safeguard period, if the rate of return on accumulated capital expenditure is in excess of 15 per cent, then the field is liable to pay PRT, but not if rates of return fall below that). As Table 3.1 reveals, in the vast majority of cases, the calculated IRR of the fields exceeds 15 per cent on the basis of the price assumptions used in the model.

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[1] In reality, there may be other criteria by which projects are judged. For example, oil companies may look at the absolute size of the NPV of a project, or more sophisticated profitability indices may be considered. Corporate considerations may also be taken into account, such as whether the proposed development fits into the company's overall investment strategy, or whether it will help them achieve other corporate aims, such as increasing market share.

Table 3.1: ***The New Fields*** **- Base Case Internal Rates of Return (Based on Actual Technology and Fiscal Regime)**

Oilfields

Oilfield	IRRs above 15%
Ness	910.0%
Blenheim	236.8%
Fife	206.1%
Hudson	203.2%
Angus	135.9%
Leven	134.6%
Glamis	102.7%
Petronella	87.8%
Columba D	75.6%
Donan	63.0%
Medwin	38.6%
Arbroath	34.7%
Moira	33.2%
Ivanhoe/Rob Roy	29.9%
Harding	27.9%
Pelican	27.2%
Osprey	25.2%
Chanter	24.9%
Nelson	23.7%
Gryphon	22.0%
Birch	21.0%
Tern	19.3%
Eider	18.9%
Scott	17.5%
Alba	16.6%
Strathspey	16.0%
Dunbar	15.9%
Brae East	15.8%

Oilfield	IRRs below 15%
Saltire	14.7%
Kittiwake	13.9%
Gannet	13.6%
Alwyn North	11.8%
Clyde	9.4%
Staffa	8.4%
Lyell	8.3%
Balmoral	7.7%
T-Block	4.7%
Cyrus	0.9%
Crawford	negative
Don	negative
Emerald	negative
Linnhe	negative

Gas Fields

Gas Field	IRRs above 15%
Beinn	148.0%
Ellon	47.6%
Amethyst	19.9%
Miller	16.5%
Bruce	16.0%

Gas Field	IRRs below 15%
Everest	12.6%
Lomond	2.8%

There are, however, a number of important exceptions where a field has been developed despite an apparently low (or even negative) IRR. In some cases, this reflects a downgrading of output and recoverable reserve projections *after* a field has come on stream, which has the result of lowering revenue forecasts. This is particularly relevant of fields such as Crawford and Staffa, where operations have been abandoned far earlier than originally intended.

Another reason why fields with an apparently unattractive IRR are developed is that the cash flows have been calculated on a 'stand-alone' basis, which sometimes may not fully reflect the economic attractiveness at a *corporate* level. In the case of Alwyn North, for example, the field's operators, Elf and Total, have an existing operation in the ring fence and can therefore claim corporation tax offsets that are not reflected in the analysis of Alwyn North's cash flows. Moreover, in the cost estimates, the field has been fully charged for oil and gas transportation costs. In reality, these charges represent a transfer cost because the French companies have a part ownership of the Ninian pipeline and the Sullom Voe terminal (which are used to transport Alwyn North's oil production), and full ownership of Frigg UK (used for gas transportation). The *expectation* of high oil prices offers another explanation for the development of the Alwyn North field. Although discovered in 1975, the operators did not apply for Annex B approval until the beginning of the 1980s, when oil prices were high, which appeared to justify the development of this high cost field. By the time of the oil price collapse in the mid 1980s, Elf and Total were already committed to the Alwyn North project.

Table 3.1 indicates that the Don field has a negative IRR. However this is based on cash flow analysis which assumes that this satellite field pays for using the facilities on Thistle. In practice, because the participants of the two fields are broadly similar, this payment will be considered a transfer payment. Thus, the economics at the corporate level will be more attractive than they appear on a stand-alone basis. A similar story is true of several other fields, including: Lyell, whose cash flow analysis includes the tariff paid by the field for the use of the Ninian pipeline system; Saltire, whose participants are equity owners of the Flotta system; and Lomond, where tariff payments to the Central Area Transmission System represent an intra-company transfer.

The low IRR assigned to Cyrus — which stands at less than 1 per cent — chiefly reflects the capital costs of BP's SWOPS floating production system, which have been fully charged to the field's development. While the cost of this vessel reduces the apparent attractiveness of Cyrus, BP built SWOPS with a long-term view of developing similar small accumulations in the future. Indeed, SWOPS has since moved to the Donan field. Thus, although the cash flow analysis assumes all the capital costs of SWOPS are written off against Cyrus, the outlay may ultimately be spread over a number of fields. In other words, if SWOPs were operated by an independent contractor, the cost would be recovered by revenues over its whole life, not just its first project.

IMPACT OF DIFFERENT TAX SCENARIOS ON FIELDS' INTERNAL RATES OF RETURN

By changing key parameters within the taxation model (described in Annex 3.1), it is possible to simulate the impact of changes to the UK fiscal regime on an individual field's IRR. It is then possible to identify those fields whose development has been sensitive to certain taxation measures. Five scenarios have been prepared, assessing the impact of the following:

- **Scenario 1: The Imposition of Royalty**. It is assumed that, in common with all fields that were granted Annex B approval before April 1982, each of *The New Fields* is liable to pay royalty. Although royalty is usually calculated on the basis of 12.5 per cent of gross revenues, certain cost items can be offset against revenues (such as a proportion of the capital and operating costs of a platform, the costs of transportation and terminals, and a notional interest allowance). Thus, in practice, the percentage of gross revenues that is paid in royalty is less than 12.5 per cent. It is assumed that

9 per cent of gross revenue would be paid in royalty by *The New Fields* under this scenario.

- **Scenario 2: The Size of the Oil Allowance**. Prior to the 1983 Oil Taxation Act, the oil allowance used for the calculation of PRT stood at 250,000 tonnes for each six-month period with a cumulative maximum of 5 million tonnes. This allowance was subsequently doubled for oilfields with Annex B approval after April 1982. Under this scenario, it is assumed that the oil allowance is *not* doubled for these fields. (Since our taxation model is based on twelve- rather than six-month periods, it is assumed, therefore, that the oil allowance for *The New Fields* stands at 500,000 tonnes per year, with a cumulative maximum of 5 million tonnes.)

- **Scenario 3: The Rate of Petroleum Revenue Tax.** Under this scenario, it is assumed that the rate of PRT remains at 75 per cent after 1983 and is *not* reduced to 50 per cent from mid-1993. Moreover, it is assumed that fields with Annex B approval after April 1993 are also subject to PRT.

- **Scenario 4: Without the 1983 Fiscal Changes**. This represents a combination of Scenarios 1 and 2, relating to royalty and the size of the oil allowance. The 1983 Finance Act abolished royalty and doubled the oil allowance for fields with Annex B approval after April 1982. This scenario assesses the impact of these measures by calculating the tax position and resulting IRR of *The New Fields* if these changes had *not* been made — i.e., if royalty was imposed *and* the oil allowance was not doubled.

- **Scenario 5: Without the 1983 and 1993 Fiscal Changes**. This represents a combination of the first three scenarios. It assumes that royalty is imposed and the oil allowance is not doubled for fields with Annex B approval after April 1982, and that the rate of PRT remains at a level of 75 per cent since 1983, and is also imposed on fields granted Annex B authorization after April 1993. In other words, this scenario can be used to indicate the profitability of *The New Fields* if the main taxation changes made in both the 1983 and 1993 Finance Acts had not taken place.

Results of the Analysis

By changing key parameters, the taxation model can be used to simulate the impact of the scenarios described above on the tax position and IRR of *The New Fields*. The results of these simulations are presented in full in Annex 3.2 (see Tables A3.2 and A3.3), and the key findings are summarized in the following paragraphs. The first of these annex tables reveals how the total tax bills of *The New Fields* would change under the different tax scenarios. The impact of these changes on each field's IRR is then revealed in Table A3.3. For the purposes of comparison, the first column of both tables includes the 'base case' — i.e., the situation under the current fiscal arrangements.

At this stage, it is important to remember that the analysis presented here is based on the assumption that the fiscal regime was not made more lenient after 1983 and 1993, but that oil companies still benefited from the cost reductions due to new technology.

The results from the analysis in this chapter provide interesting conclusions about how the economics of new field developments have been affected by key fiscal changes since 1983. For example, given existing cost structures (i.e., accepting that new cost-saving methods of production have been introduced), it is possible to identify those fields that would not have been developed in the absence of key modifications to the fiscal regime.

Scenarios 1, 2 and 3 demonstrate the *individual* impacts of the key fiscal modifications: Scenario 1 simulates the total tax bill and IRR on the assumption that royalty is not abolished for fields with Annex B approval after 1 April 1982, while Scenario 2 models the consequences of the oil allowance remaining at half its existing level. Scenario 3, meanwhile, isolates the role played by the reduction in the rate of PRT in 1993. Of these three scenarios, Scenario 1 (which models the imposition of royalty) has the greatest individual impact. Scenarios 2 and 3, on the other hand, tend to have rather a muted effect, particularly on the cash flows of the smaller fields. This reflects the fact that many such fields have no PRT liability — because their output is so low, or because of safeguard provisions, for example. Thus, changes to the size of the oil allowance or to the rate of PRT will not affect the overall tax liability or the IRR of these fields.

The most interesting and relevant scenarios to consider are numbers 4 and 5 because they simulate how the economics of *The New Fields* would look without the key changes that were actually introduced in the 1983 and 1993 Finance Acts. In order to establish whether fiscal modifications have influenced the development of a field, it is not so much the *absolute level* of the IRR that is important; rather it is how the IRR *changes* under the different scenarios. Once a target IRR has been established (i.e., the rate of return that is deemed necessary to trigger the development of a field), the information contained in Table A3.3 can be used to give an indication of those fields where fiscal measures have had a bearing on the development decision. For example, if the target IRR is set at 15 per cent, the fiscal changes that took place in either the 1983 or 1993 Finance Acts can be judged to have had an impact on the development decision if, in the absence of these changes (as simulated by Scenarios 4 and 5, respectively), the IRR falls *below* 15 per cent. This is true of the fields that are highlighted in Table 3.2 (below):[2] Alba, Brae East, Dunbar, Eider (in the

[2] There are plenty of additional cases where Scenarios 4 and 5 produce IRRs below 15 per cent. These include Alwyn North, Balmoral, Clyde, Crawford, Cyrus, Don, Everest, Gannet, Kittiwake, Linnhe, Lomond, Lyell, Staffa and the T-Block fields. However, since the base case IRR of these fields was *also* below 15 per cent (which suggests that the fields were actually developed in spite of an IRR lower than the target), it does not necessarily follow that the fiscal measures were influential in their development decision.

case of Scenario 5 only, where its IRR falls to 14.95 per cent, which has been rounded up to 15.0 per cent in the table), Strathspey, Bruce and Miller. Thus, there is a case for arguing that changes to the UK fiscal regime in 1983 and 1993 have played a role in the development decision of fields which, between them, have contributed an average 400,000 b/d to total UK North Sea oil production since 1994.

Table 3.2: Fields where, given Existing Technology, the 1983 and 1993 Fiscal Changes have Influenced Their Development.[1] IRR (Per cent)

	Base Case	Without 1983 Fiscal Changes (Scenario 4)	Without 1983 and 1993 Fiscal Changes (Scenario 5)
Alba	16.6%	14.1%	13.8%
Brae East	15.8%	14.0%	12.9%
Bruce	16.0%	13.9%	12.8%
Dunbar	15.9%	12.3%	12.4%
Eider	18.9%	15.1%	15.0%
Miller	16.5%	13.4%	12.6%
Strathspey	16.0%	12.0%	11.9%

Note: [1] Determined as those fields where base case IRR is above 15 per cent, but where IRR would fall below this without the fiscal changes.

An examination of Annex Table A3.3 reveals that, while not making any difference to the development decision, the fiscal measures of 1983 and 1993 have had quite dramatic repercussions on the IRR of some of the other *New Fields*. In the case of Fife, for example, the model suggests that, without the fiscal relaxation of 1983 and 1993, its IRR would drop from 206 to 148 per cent (although, clearly, the latter exceeds the target level to justify development). Hudson and Ness are other fields where economic viability has been improved markedly as a result of the fiscal changes.

It must of course be remembered that, in order to *isolate* the role played by fiscal changes to the decision to develop new oilfields, it is necessary to take into account the contribution made by new technology. As discussed in Chapter 2, technological progress has played an important role in reducing the costs associated with developing oilfields, which, in turn, will have boosted the IRRs of *The New Fields* above levels that would be experienced in the absence of the new technology. This is addressed in Chapter 4, where the impact of advances in technological progress in encouraging the development of oilfields in the North Sea is assessed in greater detail.

SUMMARY POINTS

- Typically, the decision on whether or not to develop a new field will depend on the operator's expectations of future revenues vis-à-vis costs. Internal rates of return

(IRR) can be calculated, which represent the discount rate at which the net present value of a project is zero. If the IRR exceeds a target level, then usually the decision is taken to go ahead with the project.

- Sometimes the decision is taken to develop a field despite an apparently low (or even negative) IRR. This may reflect the downgrading of reserve (and hence) revenue projections *after* a field has come on stream. Furthermore, because they are calculated on a 'stand-alone' basis, the IRRs may not fully reflect the economic attractiveness of a field at the *corporate* level.

- The use of a taxation model permits an assessment of the impact of different fiscal scenarios on fields' IRRs. The results suggest that, given a target IRR of 15 per cent and that prices rise at an annual rate of 3 per cent in nominal terms from 1997, the main taxation changes contained in the 1983 and 1993 Finance Acts triggered the development of several fields, which, between them, have contributed an average 400,000 b/d to total UK North Sea output since 1994.

Chapter 4: The Impact of Cost-Saving New Technology

In Chapter 3, the influence of the key fiscal changes of 1983 and 1993 on the decision to develop *The New Fields* was assessed using a cash flow model. Under the existing cost structure of fields (in other words, taking into account the advances in cost-saving technology that have taken place), the model highlighted those fields which became commercially viable as a result of fiscal relaxation. In this chapter, the technology side of the equation is examined. The cash flow model is used to examine the role played by new technology in boosting the economic viability of new field ventures. By assuming that the existing fiscal arrangements are in place, the analysis in this chapter will attempt to identify those fields that would not have been developed in the absence of new technology. Moreover, the impact of new technology on the members of *The 1985 Group* of fields is also considered.

As discussed in previous chapters, a large proportion of the oilfields that have come on stream over the past decade represent relatively small developments, which are often marginal from an economic point of view. The volume of recoverable oil and gas from such fields is frequently very low, resulting in a short lifespan of the field. Complex geology and harsh operating conditions can further reduce the attractiveness of developing such fields. The conventional means of developing an oilfield — by installing a fixed production platform — is rarely cost effective under such circumstances. Indeed, of the 58 members of *The New Fields* category, only 20 have been developed by means of platforms, and even some of these cannot be considered to be *conventional* platforms because they have no personnel and are remotely controlled, for example.

Instead, the development of small, marginal fields can often hinge on the ability of operators to find alternative, low cost methods of exploitation. Fortunately, technological progress is providing such methods, with the emergence of subsea systems, floating production vessels and deviated/horizontal wells. In order to assess the contribution made by such new technology on the decision to develop new fields, it is necessary to adjust the cost profiles of fields that are exploited by unconventional means to reflect the situation that would exist in the *absence* of new technology.

METHODOLOGY

Clearly, this is a difficult modelling task since data on the costs of the alternative technologies are not available for the actual fields. To avoid this problem, the approach that has been chosen is to assume that, in the absence of the new technology, the only means of exploitation of an oil reservoir is through the installation of a conventional production platform. Thus, for all those fields that are actually being exploited by other means[1] (including subsea systems, deviated/extended wells and floating production systems), costs are re-estimated on the basis that a conventional platform was used instead.[2]

This analysis is described in detail in Annex 4; the paragraphs that follow present a summary of the results.

Choosing a 'Representative' Capital Cost

As highlighted in Annex 4, analysis of the capital costs of those 39 UK North Sea oilfields which have been exploited by means of a production platform reveals that the only significant variable in explaining the capital cost of the platform is the size of the recoverable reserve base of the field.

To derive a 'representative' estimate, the capital costs of platforms of fields with small reserve bases are used as a guide. The following assumptions are made:

- For fields with total reserves of 100 million barrels of oil equivalent or less, it is estimated that the capital cost of a conventional platform would be £230 million in 1996 prices.
- For fields with total reserves of between 100 and 150 million barrels of oil equivalent, it is estimated that the capital cost would be £380 million in 1996 prices.

On the basis of these capital cost assumptions, the cash flows of those fields that are actually exploited by 'non-platform' methods are adjusted as if a platform is installed instead. All other capital costs (including development drilling and the cost of flowlines) remain unchanged. It is also necessary to adjust the cash flows to take into account the higher abandonment costs associated with a platform, compared to other production methods (such as subsea manifolds, deviated wells and floating production systems).

Choosing Appropriate Operating Costs

As discussed in Annex 4, by imposing the assumption that all fields are exploited by means of a conventional production platform, it is necessary not only to re-estimate the capital costs of fields that are actually exploited by alternative means, but also to adjust *operating costs* as well.

In estimating what these costs would be if the fields were to be exploited by a conventional platform, the operating costs of the same group of fields that were used to find

[1] Most of these fields belong to *The New Fields* category, although a small number — Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa — are members of *The 1985 Group* and are included in the analysis.

[2] The costs of fields that are exploited by platforms have *not* been adjusted in any way.

a 'representative' capital cost — i.e., those with small reserve bases — are taken as a guide. To be used in the cash flow analysis, it is necessary to estimate operating costs on an *annual* basis, using the following assumptions:

- For fields with total reserves of 100 million barrels of oil equivalent or less, annual real (1996) operating costs are calculated according to the equation:

$$y = 11.89 + 0.91x$$

where:

y = annual real (1996) operating costs

x = annual production ('000 b/d, oe)

- For fields with total reserves of between 100 and 150 million barrels of oil equivalent, annual real (1996) operating costs are calculated according to the equation:

$$y = 14.58 + 0.98x$$

where:

y = annual real (1996) operating costs

x = annual production ('000 b/d, oe)

Other Assumptions

To re-cap, the purpose of the analysis presented in this chapter is to revise the cost profiles of those fields that have adopted non-conventional means of production (e.g., subsea systems, floating production systems, extended reach wells) on the basis that the only means of exploitation available to operators is the installation of a platform. In this way, the impact of new production technology is largely removed.

To avoid over-complication, it is further assumed that recoverable reserves and the rate of production (and hence lifespan) of the fields is the same regardless of the method of exploitation employed. This is admittedly a bold assumption. It is well known, for example, that horizontal drilling can permit the more efficient drainage of a reservoir, resulting in higher estimates of a field's recoverable reserves than if the field was exploited by conventional vertical drilling. However, this assumption simplifies the analysis because it means no revisions need to be made to the production and revenue streams of each field's cash flow.

In terms of the *timing* of capital cost expenditure, it is assumed that the costs associated with the platform structure, its equipment and installation are incurred in the first years of the field's life. In practice, these capital costs are typically spread over a period of three to five years. However, since losses can be carried forward for tax purposes, and since the period under examination is associated with relatively low rates of inflation, this assumption will not make a significant difference to the calculation of a field's profitability.

Although the analysis simulates the capital costs of installing a platform on the fields, rather than other production methods — such as subsea systems, floating production systems and deviated/extended wells — all other capital costs (such as those associated with development drilling and the cost of flowlines) are left unchanged from those estimates provided by Wood Mackenzie in its North Sea Service.

ANALYSIS OF THE RESULTS

For those fields that are actually exploited by unconventional means, their individual cash flows are adjusted to reflect the estimated cost situation that would have existed if their development had involved the installation of a conventional production platform. On the basis of these new costs, the taxation model re-calculates each field's tax liability (under existing fiscal arrangements), cash flow and internal rate of return. By comparing these 'adjusted' IRRs with those that exist under *actual* cost conditions (the 'base case'), it is possible to highlight those fields whose development has been sensitive to the cost savings that have arisen from new production technology.[3]

These comparisons of IRR are presented in full in Table 4.1. (An analysis of *all* the *New Fields* is included, whilst only those members of *The 1985 Group* that are not exploited by means of a conventional production platform are featured.) Meanwhile, Table 4.2 highlights those fields where there is evidence that, given the existing fiscal regime, new technology has influenced the field development. As in Chapter 3, this is determined by assuming a target IRR of 15 per cent. Cost-saving technology can be judged to have had an impact on the development decision of a field if the cash flow model indicates an IRR of 15 per cent or above in the base case (i.e., assuming existing technology and fiscal arrangements) but *below* the target level *in the absence of cost-saving technology*. This is true for all the fields listed in Table 4.2.

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[3] This will include all types of cost-saving measures, such as those arising from CRINE.

Table 4.1: Comparison of Internal Rates of Return under the Base Case and in the Absence of New Technology. Per cent

	Base Case[1]	Without New Technology[2]
New Fields (Oil)		
Ness	910.0%	negative
Blenheim	236.8%	negative
Fife	206.1%	negative
Hudson	203.2%	23.0%
Angus	135.9%	negative
Leven	134.6%	negative
Glamis	102.7%	negative
Petronella	87.8%	2.2%
Columba D	75.6%	negative
Donan	63.0%	negative
Medwin	38.6%	negative
Arbroath	34.7%	14.5%
Moira	33.2%	negative
Ivanhoe/Rob Roy	29.9%	17.7%
Harding	27.9%	27.9%
Pelican	27.2%	5.7%
Osprey	25.2%	11.3%
Chanter	24.9%	negative
Nelson	23.7%	23.7%
Gryphon	22.0%	-2.9%
Birch	21.0%	-2.8%
Tern	19.3%	19.3%
Eider	18.9%	18.9%
Scott	17.5%	17.5%
Alba	16.6%	16.6%
Strathspey	16.0%	5.2%
Dunbar	15.9%	15.9%
Brae East	15.8%	15.8%
Saltire	14.7%	14.7%
Kittiwake	13.9%	13.9%
Gannet	13.6%	13.6%
Alwyn North	11.8%	11.8%
Clyde	9.4%	9.4%
Staffa	8.4%	negative
Lyell	8.3%	negative
Balmoral	7.7%	5.1%
T-Block	4.7%	4.7%
Cyrus	0.9%	negative
Crawford	negative	negative
Don	negative	negative
Emerald	negative	negative
Linnhe	negative	negative

Notes:

1. Assumes existing technology and fiscal regime.

2. Assumes there is no new technology (i.e., fields can only be exploited by means of a permanent production platform) but actual fiscal regime is in place.

Table 4.1 (continued): Comparison of Internal Rates of Return under the Base Case and in the Absence of New Technology. Per cent

	Base Case	Without New Technology
The 1985 Group[3]		
Deveron	207.6%	negative
Highlander	129.1%	23.4%
Argyll	55.0%	14.3%
Scapa	46.1%	7.9%
Buchan	24.4%	25.9%
Duncan	21.3%	negative
Innes	16.0%	negative
New Fields (Gas)		
Beinn	148.0%	negative
Ellon	47.6%	negative
Amethyst	19.9%	2.4%
Miller	16.5%	16.5%
Bruce	16.0%	16.0%
Everest	12.6%	12.6%
Lomond	2.8%	2.8%

Notes:
3. In this category, only those fields that do not have a conventional production platform are included.

In many cases, new technology has provided a dramatic boost to the commercial viability of fields. Without cost-saving technology, the model indicates that Angus, Birch, Blenheim, Chanter, Columba D, Donan, Fife, Glamis, Leven, Medwin, Moira, Ness, Deveron, Duncan, Beinn and Ellon would have negative IRRs — which implies that their development using conventional production techniques would have resulted in their operators *losing* money — whereas, in the reality of new production methods, their base case IRRs are well in excess of the 15 per cent target. Indeed, in several instances, the base case IRR is over 100 per cent.

Although a large *number* of fields are listed in Table 4.2, many of them represent small developments. This is reflected by the combined output from the fields, which is relatively modest, although it has been climbing steadily in recent years. In 1994, production from these fields accounted for 167,000 b/d; this rose to approximately 230,000 b/d in 1995 and 275,000 b/d in 1996.

Table 4.2: Fields where, given the Existing Fiscal Regime, Cost-Saving Production Technology has Influenced their Development[1]. IRR. Per cent

	Base Case	Without New Technology
New Fields (Oil)		
Angus	135.9%	negative
Arbroath	34.7%	14.5%
Birch	21.0%	-2.8%
Blenheim	236.8%	negative
Chanter	24.9%	negative
Columba D	75.6%	negative
Donan	63.0%	negative
Fife	206.1%	negative
Glamis	102.7%	negative
Leven	134.6%	negative
Medwin	38.6%	negative
Moira	33.2%	negative
Ness	910.0%	negative
Osprey	25.2%	11.3%
Pelican	27.2%	5.7%
Petronella	87.8%	2.2%
Strathspey	16.0%	5.2%
The 1985 Group		
Argyll	55.0%	14.3%
Deveron	207.6%	negative
Duncan	21.3%	negative
Innes	16.0%	negative
Scapa	46.1%	7.9%
New Fields (Gas)		
Amethyst	19.9%	2.4%
Beinn	148.0%	negative
Ellon	47.6%	negative

Note: 1. Determined as those fields where base case IRR is above 15 per cent, but where IRR would fall below that in the absence of new technology.

THE IMPACT OF NEW TECHNOLOGY ON PRODUCTION FROM *THE 1985 GROUP* OF FIELDS

It is clear from the analysis presented above that advances in technology have been pivotal to the decision to develop a large number of *The New Fields* (and a few members of *The 1985 Group* that have been exploited by unconventional means), which have contributed to the upturn in UK North Sea oil output in the 1990s. However, new technology has also helped to boost oil production from the more established fields through improved oil recovery techniques. In this section, an attempt is made to quantify the impact of new technology on the performance of *The 1985 Group* of fields.

Over time, there has been an increase in the estimates of total recoverable reserves from *The 1985 Group* of fields,[4] and this has helped to maintain oil production from these fields at higher-than-expected levels. In general, changes in recoverable reserve estimates reflect two main factors:

'reserve creep', which is simply the collection of more complete information on the reserve base of an oil reservoir arising from early production experience and as the results of new appraisal programmes come to light; and

'technology-induced' increases in reserve estimates that are due to the reclassification of some of the original oil-in-place from uneconomic to economically recoverable as the result of technology-induced cost reductions.

Although it can be argued that progress in seismic technology has improved appraisal techniques, thereby boosting reserve estimates, 'reserve creep' is a phenomenon that is generally regarded as being independent of new technology. There are compelling commercial reasons why geologists and oil companies may initially underestimate the recoverable reserve base of a field — to factor in some 'safety margin' in the decision to develop the field, for example. Meanwhile, the geology of a reservoir may be so complex that the only way to gather more information about its structure is simply to drill wells and/or learn from early production experience. A rule-of-thumb often adopted as an industry standard is that, on average, estimates of recoverable reserves will increase by between 40 and 45 per cent over the first six or seven years of a field's life, simply due to increased knowledge of the reservoir (i.e., due to 'reserve creep').

Technology-induced increases in recoverable reserve estimates result from a number of factors. Many of the established fields have taken advantage of drilling technology, and have deviated or horizontal wells which provide far greater contact with the producing zone — resulting in a more efficient drainage of the reservoir. Meanwhile, extended reach wells enable the recovery of oil in pockets of the reservoir that were previously regarded as being unobtainable or which had not been discovered. Advances in seismic surveying techniques have helped to identify these additional reserves, and have facilitated accurate infill drilling.

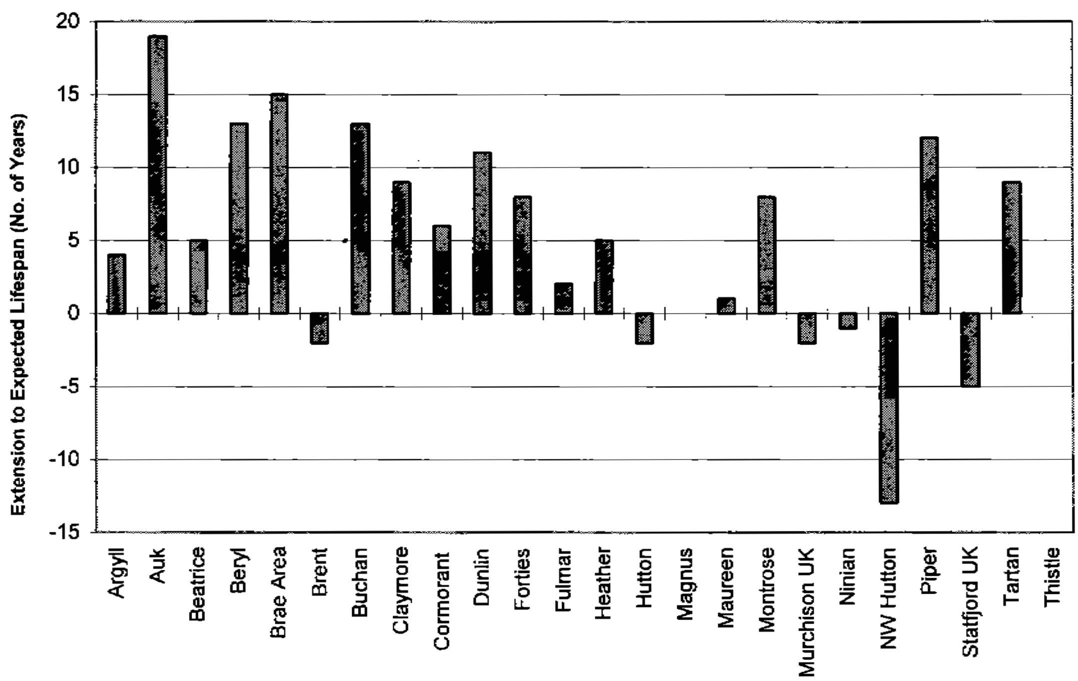
By reducing operating costs, new technology has also enabled the extension of the lifespans of many of the established fields in which they can operate economically. By operating for longer, more oil reserves can be exploited. Similarly, the emergence of satellite fields can improve the recovery of the fields to which they are tied back, by allowing production to continue for longer than would otherwise have been economic on a stand-

[4] In a few cases, reserve estimates have been *downgraded* over time. However, this is more than offset by upward revisions for the majority of fields.

alone basis. (For example, the development of the Arbroath field has helped to extend the life of the Montrose field — which processes and exports Arbroath's production — by eight years.)

Diagram 4.1 highlights the extension of the anticipated field lives of *The 1985 Group*, by comparing recent (1996) forecasts of their lifespans with forecasts made in the early 1980s. In some cases — notably Auk, Beryl, Brae Area and Buchan — the extension has been quite significant.[5]

Diagram 4.1: *The 1985 Group* - Extension to Lifespans



Distinguishing between 'Reserve Creep' and Technology-Induced Reserve Increases

Rather than speculate on how revisions to estimates of recoverable reserves translate into *annual* movements in oil production,[6] it seems more appropriate to quantify the changes in

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[5] In Diagram 4.1, a negative bar implies that the forecast of the field's expected lifespan made in 1996 is shorter than the forecast lifespan in 1983. North West Hutton is notable in this respect. Development drilling has revealed that the reservoir quality is considerably poorer than originally thought and production forecasts and recoverable reserve estimates have been significantly downgraded. As a result, the field's productive life has been scaled back to fourteen years, compared with estimates of 27 years when the field first came on stream. The expected lifespans of Brent, Murchison UK, Ninian and Statfjord UK have also been shortened, but only very modestly. These cases differ markedly from the North West Hutton example because estimates of recoverable reserves from these fields have been *upgraded* over time, and annual production volumes are often much *higher* than earlier forecasts.

[6] This would be a particularly difficult exercise because an increase in recoverable reserve estimates can be expected to have a number of different implications for the production profile of a field — including an extension of its lifespan; increases in annual production levels from those originally anticipated; and a slowing of the natural decline in the production of the field over time.

the recoverable reserves estimates of *The 1985 Group* of fields since 1985 (the starting point of our analysis), distinguishing between increases that are due to 'reserve creep' and those that reflect improvements in technology. In order to make this distinction, the rule-of-thumb mentioned at the beginning of this section is adopted — i.e., it is assumed that estimates of recoverable reserves of a field will increase by 45 per cent over the first seven years of a field's productive life, simply due to 'reserve creep'. Any further increase is then assumed to be the result of new technology.[7]

On the basis of these assumptions, Table 4.3 presents the increase in estimates of recoverable reserves that has taken place between 1985 and 1996 for each of *The 1985 Group* of fields, highlighting how much of the increase has been due to 'reserve creep', and how much is the result of new technology. It can be seen that, over the time period, estimated recoverable reserves have risen by a total of approximately 2.9 billion barrels of oil equivalent. The analysis suggests that the bulk (96 per cent) of this increase is attributable to new technology. This is to be expected: by 1985, many of the fields listed in Table 4.3 had already been in production for *more* than seven years, and had therefore passed the point at which 'reserve creep' is assumed to have taken place.

Table 4.3 reveals that the most significant technology-induced increase in reserves since 1985 has been at the Beryl field. This reflects the new drilling system recently installed on Beryl A's rigs, which has enabled horizontal and multilateral wells to be drilled. The first of these was drilled in 1995 and has a horizontal length of over 4,000 feet. This well (and those that are planned for the future) will reach significant amounts of by-passed oil left behind from earlier wells which produced excess water.

Meanwhile, the Brent redevelopment project, which began in 1994, and which will involve a significant upgrading of the field's facilities, has been chiefly responsible for the 293 million barrel increase in estimated recoverable reserves over the past decade or so.

Elsewhere, the upgrading of reserves at Forties by a massive 470 million barrels reflects the artificial lift programme, which was implemented in the early 1990s, and a new drilling programme that will access oil sitting in small pockets of the reservoir.

Finally, in the case of Magnus, where reserves have been upgraded to the tune of 230 million barrels — over half of which is estimated to be technology-induced — a field life extension project was sanctioned in July 1994, and additional reserves are expected to be tapped following the drilling of two side-track wells with gas lift completions, and the installation of a state-of-the-art subsea water injection manifold. Meanwhile, a new high angle well utilizing existing subsea facilities and drilled in early 1995 to the north end of the main field reservoir has also helped to boost recoverable reserve estimates.

[7] In practice, the 45 per cent condition is not binding. In other words, there are very few cases in which a field's reserves have been upgraded by more than 45 per cent during the first seven years of its life. Thus, the most intuitive part of the model definition of reserve creep is the time limit.

Table 4.3: *The 1985 Group* - Increase in Estimates of Recoverable Reserves - Distinction between 'Reserve Creep' and Technology-Induced Increases (since 1985). Million Barrels of Oil [1]

	Net Increase in Estimates of Recoverable Reserves [2]	---- *of which* ---- Reserve Creep [3]	Technology-Induced [4]
Argyll	17	0	17
Auk	21	0	21
Beatrice	29	0	29
Beryl	722	0	722
Brae Area	66	66	0
Brent	293	0	293
Buchan	60	7	53
Claymore	167	0	167
Cormorant	66	0	66
Deveron	2	2	0
Duncan	1	1	0
Dunlin	98	0	98
Forties	470	0	470
Fulmar	135	0	135
Heather	31	0	31
Highlander	42	20	22
Hutton	-7	-7	0
Innes	3	1	2
Magnus	230	103	127
Maureen	56	51	4
Montrose	5	0	5
Murchison UK [5]	19	0	19
Ninian	103	0	103
NW Hutton	-159	-159	0
Piper	123	0	123
Scapa	65	19	47
Statfjord UK [5]	147	0	147
Tartan	43	23	20
Thistle	17	0	17
Total	**2,866**	**127**	**2,739**

Source: Derived from data published in *The Brown Book*, various issues.

Notes:

1. The conversion factor used is: 1 tonne of oil is equivalent to 7.35 barrels.

2. Estimates of recoverable reserves made in 1996 compared to those made in 1985.

3. It is assumed that estimates of recoverable reserves rise by 45 per cent over the first seven years of a field's life due to 'reserve creep', which is simply increased knowledge of the reservoir.

4. Any increase in recoverable reserve estimates that is in excess of 'reserve creep' is assumed to be technology-induced. This includes increases due to seismic surveys, the drilling of horizontal wells, redevelopment programmes and the extension of a field's life because of declining operating costs.

5. Represents the UK's share of overall reserves.

SUMMARY POINTS

- The use of new production techniques such as subsea systems, floating production systems and deviated/horizontal wells has reduced the costs of developing small oilfields, compared to those associated with the use of a conventional production platform.

- To model the impact of such cost-saving technology, it is assumed that all fields are exploited by means of a production platform. This means re-estimating the capital and operating costs of those fields that are actually exploited by alternative methods, on the basis of the cost information available for existing platforms.

- For those fields that are exploited by unconventional means, their individual cash flows are adjusted to reflect the estimated cost situation that would have existed if a production platform had been used instead. The cash flow model introduced in Chapter 3 can then be used to recalculate each field's tax liability, cash flow and internal rate of return (IRR). By comparing these 'adjusted' IRRs with those that exist under actual cost conditions (the 'base case'), it is possible to highlight those fields whose development has been sensitive to cost savings arising from new production techniques, given current fiscal arrangements.

- Taking a target IRR of 15 per cent, the model suggests that a large number of *The New Fields* would not have been developed in the absence of new production techniques, even in the light of the favourable fiscal regime. In recent years, oil supplies from these fields have accounted for between 170,000 and 275,000 b/d of the UK North Sea total.

- New technology has also helped to boost oil production from the more established fields through improved oil recovery techniques. It is estimated that recoverable reserves from *The 1985 Group* of fields have increased by over 2.7 billion barrels of oil equivalent since 1985 as a result of technological progress.

Chapter 5: Comparing the Fiscal and Technology Effects

This chapter pulls together the results of the analysis contained in Chapters 3 and 4. In addition, the cash flow model is used to examine the economic viability of fields in the absence of *both* fiscal reform and new technology. The fields included in the analysis are all those belonging to *The New Fields* category and the seven members of *The 1985 Group* that have been developed by 'non-conventional' means — Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa.

The main objectives of this chapter are to identify:

- those fields that are likely to have been developed even in the absence of both the fiscal changes and advances in production technology;
- those fields where a *combination* of fiscal relaxation and cost-saving technology has apparently precipitated development;
- those fields whose development has been triggered solely by the fiscal relaxation of 1983 and 1993; and
- those fields that have been developed solely as a result of cost-saving new technology.

Armed with this knowledge, it is possible to simulate how the profile of UK North Sea oil production since 1985 would have looked in the absence of either, or both, fiscal relaxation and cost-saving new production.

ANALYSIS OF THE RESULTS

Comparisons of IRRs under different scenarios are presented in full in Table 5.1, which displays four columns of results.

- The first column represents the *base case* IRRs, which are calculated under actual cost and fiscal conditions.
- The second column represents the opposite extreme, and shows what the model calculates the IRRs of the fields would have been if the main fiscal changes of 1983 and 1993 had *not* taken place (i.e., no fiscal relaxation), *and* if all fields are exploited by means of a production platform (i.e., no new technology). In other words, the differences between these IRRs and those of the base case indicate the *combined effect* of the fiscal changes and new technology on the economic viability of a field.
- The third column of results assumes existing technology (i.e., cost estimates have *not* been revised), but simulates what the IRRs would be in the absence of the key changes of the 1983 and 1993 Finance Acts.[1] (This analysis is described in Chapter 3.) Put another way, these IRRs reflect the situation if new technology has taken

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[1] In other words, it is assumed that royalty is not abolished and oil allowance is not doubled for fields with Annex B approval after 1 April 1982; and PRT remains at 75 per cent and applies to *all* fields. As such, this column duplicates the results in the final column of Table A3.3 in Annex 3, although the coverage is extended to include the seven members of *The 1985 Group* that are exploited by 'non-conventional' production methods.

place, but if the UK government did not relax the fiscal regime in 1983 and 1993. By assuming a target IRR, the results in this column can therefore be used to identify those fields whose development would not have gone ahead in the absence of the fiscal changes.

- The IRRs presented in the final column of Table 5.1 reproduce the findings of Chapter 4. It is assumed that the main fiscal changes of 1983 and 1993 *did* occur, but, for those fields exploited by alternative means, cost estimates have been revised to reflect the situation if a conventional fixed production platform had been used instead.[2] By assuming a target IRR, the results in this column can therefore be used to identify those fields whose development would not have gone ahead in the absence of cost-saving new technology.

The interpretation of Table 5.1 can be illustrated by way of an example. Consider, for instance, the Osprey development. Since this field was granted Annex B in 1988, it has benefited from the Finance Act changes of 1983 and 1993. Moreover, as it has been developed by two subsea manifolds tied back to the Dunlin platform, the economics of the field have been improved as a result of cost-saving new technology. The cash flow model calculates that under the base case — i.e., given actual fiscal and technology conditions — the IRR of the field is 25.2 per cent, as given in the first column of Table 5.1. In the absence of both the fiscal changes and new technology, the IRR of Osprey is calculated as 8.3 per cent (second column). In other words, the *combined impact* of the fiscal relaxation and new technology has been to raise the IRR of the field by around 17 percentage points.

Given current technology, but assuming that the fiscal changes of 1983 and 1993 had not taken place, the cash flow model suggests that the IRR of Osprey would be 21.4 per cent (third column of the table). Comparing this with the base case (first column) suggests that the decision of the UK government to introduce the fiscal changes of 1983 and 1993 improved the IRR of the Osprey development from 21.4 to 25.2 per cent. Given a target IRR of 15 per cent, it also shows that Osprey did not need the fiscal changes to precipitate its development: it would have exceeded the target anyway.

[2] Of course, for those fields that are actually exploited by 'conventional ' means (i.e., by production platforms), the IRRs presented in the final column of Table 5.1 will be identical to the 'base case' because their costs have not been adjusted.

Table 5.1: Comparisons of IRRs under Different Scenarios. Per cent

	Base Case	Without Fiscal Changes *and* New Technology[1]	Without Fiscal Changes [2]	Without New Technology [3]
	Fiscal Relaxation	No Fiscal Relaxation	No Fiscal Relaxation	Fiscal Relaxation
	New Technology	No New Technology	New Technology	No New Technology
New Fields (Oil)				
Alba	16.6%	13.8%	13.8%	16.6%
Alwyn North	11.8%	10.4%	10.4%	11.8%
Angus	135.9%	negative	105.8%	negative
Arbroath	34.7%	11.3%	27.8%	14.5%
Balmoral	7.7%	2.3%	5.0%	5.1%
Birch	21.0%	negative	17.8%	-2.8%
Blenheim	236.8%	negative	196.7%	negative
Brae East	15.8%	12.9%	12.9%	15.8%
Chanter	24.9%	negative	20.4%	negative
Clyde	9.4%	6.6%	6.6%	9.4%
Columba D	75.6%	negative	54.5%	negative
Crawford	negative	negative	negative	negative
Cyrus	0.9%	negative	-0.7%	negative
Don	negative	negative	negative	negative
Donan	63.0%	negative	63.0%	negative
Dunbar	15.9%	12.4%	12.4%	15.9%
Eider	18.9%	15.0%	15.0%	18.9%
Emerald	negative	negative	negative	negative
Fife	206.1%	negative	148.4%	negative
Gannet	13.6%	11.3%	11.3%	13.6%
Glamis	102.7%	negative	87.4%	negative
Gryphon	22.0%	negative	18.2%	-2.9%
Harding	27.9%	21.7%	21.7%	27.9%
Hudson	203.2%	16.6%	107.0%	23.0%
Ivanhoe/Rob Roy	29.9%	13.5%	22.9%	17.7%
Kittiwake	13.9%	10.2%	10.2%	13.9%
Leven	134.6%	negative	94.4%	negative
Linnhe	negative	negative	negative	negative
Lyell	8.3%	negative	4.0%	negative
Medwin	38.6%	negative	28.9%	negative
Moira	33.2%	negative	26.0%	negative
Nelson	23.7%	19.4%	19.4%	23.7%
Ness	910.0%	negative	536.4%	negative
Osprey	25.2%	8.3%	21.4%	11.3%
Pelican	27.2%	1.7%	23.0%	5.7%
Petronella	87.8%	negative	77.2%	2.2%
Saltire	14.7%	12.0%	12.0%	14.7%
Scott	17.5%	15.1%	15.1%	17.5%
Staffa	8.4%	negative	-0.5%	negative
Strathspey	16.0%	2.5%	11.9%	5.2%
T-Block	4.7%	2.0%	2.0%	4.7%
Tern	19.3%	15.6%	15.6%	19.3%

Notes:

1. Assumes that fields can only be exploited by means of a permanent fixed production platform and that the Finance Act changes of 1983 and 1993 did not occur.
2. Assumes current technology, but that the Finance Act changes of 1983 and 1993 did not occur.
3. Assumes that fields can only be exploited by means of a permanent fixed production platform but Finance Act changes of 1983 and 1993 did occur.

Table 5.1 (continued): Comparisons of IRRs under Different Scenarios. Per cent

	Base Case	Without Fiscal Changes *and* New Technology	Without Fiscal Changes	Without New Technology
	Fiscal Relaxation New Technology	No Fiscal Relaxation No New Technology	No Fiscal Relaxation New Technology	Fiscal Relaxation No New Technology
The 1985 Group [4]				
Argyll	55.0%	14.3%	55.0%	14.3%
Buchan	24.4%	25.4%	24.3%	25.9%
Deveron	207.6%	negative	176.6%	negative
Duncan	21.3%	negative	5.2%	negative
Highlander	129.1%	18.2%	97.0%	23.4%
Innes	16.0%	negative	8.2%	negative
Scapa	46.1%	4.4%	35.5%	7.9%
New Fields (Gas)				
Amethyst	19.9%	negative	16.9%	2.4%
Beinn	148.0%	negative	117.6%	negative
Bruce	16.0%	12.8%	12.8%	16.0%
Ellon	47.6%	negative	41.4%	negative
Everest	12.6%	10.5%	10.5%	12.6%
Lomond	2.8%	-1.5%	-1.5%	2.8%
Miller	16.5%	12.6%	12.6%	16.5%

Note:

4. In this category, only those fields that do not have a conventional production platform are included.

The final column of Table 5.1 indicates that the IRR of Osprey would have been 11.3 per cent if it had been developed by using a conventional production platform (i.e., it did not benefit from cost-saving new technology), but assuming the actual fiscal arrangements. Thus, if new technology had not taken place, the IRR of the Osprey field would have been approximately 14 percentage points lower than is in fact the case. This confirms that it was the impact of new technology that made the field economically viable.

The Development Decision

By assuming that the decision to proceed with the development of a field depends on a certain target IRR being achieved, it is possible to use the results contained in Table 5.1 to draw conclusions about the respective roles played by both fiscal reform and new technology in triggering field developments since 1985.

In common with the preceding chapters, it will be assumed that the target IRR is 15 per cent (although the results in Table 5.1 could also be used to determine the implications of choosing different targets[3]). The choice of 15 per cent, however, does mean that the cash flow model is unable to determine fully the factors responsible for triggering the development of those fields which have base case IRRs below 15 per cent — in other

[3] A consideration of choosing different target IRRs is presented in Chapter 6.

words, fields that have *actually* come on-stream despite apparently unattractive IRRs.[4] Nevertheless, the model *can* be used in such cases to show which effect — fiscal relaxation or new technology — has had the *stronger* impact on the economics of these fields.

Consider, for example, the case of the Lyell development, which has a base case IRR of 8.3 per cent, which is below our assumed target of 15 per cent. The third column of Table 5.1 reveals that, in the absence of the fiscal changes of 1983 and 1993 — but with existing technology — the IRR of the field would fall to 4.0 per cent. If the cost reductions associated with new technology are excluded, but actual fiscal arrangements are assumed, the model calculates that the IRR would be negative (see the final column of Table 5.1). Thus, it can be concluded that the economic viability of the Lyell field has been more sensitive to advances in new technology than to fiscal factors (although, by assuming a target IRR of 15 per cent, the model cannot explain the factors precipitating the development of the field). Table 5.2 lists all those fields with base case IRRs below the target, whose development cannot be explained by the model, although the table does highlight whether the economics of the venture are more sensitive to new technology or to the 1983 and 1993 fiscal changes.

Table 5.2: Fields with Base Case IRRs below 15 Per Cent (Highlighting whether IRR is more Sensitive to Fiscal or Technology Factors)

	Dominant Effect [1]
Alwyn North	Fiscal
Balmoral	Fiscal
Clyde	Fiscal
Crawford	Technology
Cyrus	Technology
Don	Technology
Emerald	Technology
Everest	Fiscal
Gannet	Fiscal
Kittiwake	Fiscal
Linnhe	Technology
Lomond	Fiscal
Lyell	Technology
Saltire	Fiscal
Staffa	Technology
T-Block	Fiscal

Note:
1. This column reveals whether new technology or fiscal changes have had the *greater* impact on a field's IRR (even though this effect cannot explain the decision to develop).

[4] As discussed in Chapter 3, there are a number of reasons why the development of certain fields has gone ahead despite apparently low (or even negative) IRRs. These include the downward revision of reserve/production estimates after start-up, and/or that the economics of fields as calculated on a *corporate* basis may be more attractive than those suggested on a *stand-alone* basis.

Fields that would have been Developed even in the Absence of both Fiscal Relaxation and New Technology

The second column of results in Table 5.1 reveals the *combined impact* of technological and fiscal factors on the economic viability of the fields, by estimating the IRRs under the assumption that the fiscal changes of 1983 and 1993 did not occur, *and* cost-saving new technology was not available (thus the cost of the fields reflects that associated with the installation of a fixed production platform). In the absence of *both* new technology and fiscal reforms, 49 of the 56 fields listed in Table 5.1 would not meet the 15 per cent IRR development criteria. Indeed, 28 of the fields would have *negative* IRRs in the absence of both factors, which means that their development would result in the operators making a *loss.*

There are thus only seven fields that would have been developed — assuming a target IRR of 15 per cent — in the absence of both fiscal relaxation and cost-saving new technology. The full list of these fields is: Buchan, Harding, Highlander, Hudson, Nelson, Scott and Tern.

Of these fields, Nelson and Scott have had the greatest impact on UK North Sea oil production in recent years, jointly contributing over 300,000 b/d since 1994. Given the apparently favourable economics of the fields listed above, why were they not developed earlier?

Harding, Hudson and Nelson were discovered after 1985 and obviously could not have been developed in the earlier period. The other fields — notably Scott — had complex geology and highly faulted reservoirs, requiring lengthy appraisal programmes before the decision was taken to proceed with their development.

Fields whose development has been Triggered by the Combination of Fiscal and Technology Changes

There are a small number of fields whose development, according to the model, cannot be attributed solely to new technology or the key fiscal changes, but rather to the *combination* of these two factors. These fields are Strathspey, Duncan and Innes. In the case of Strathspey, for example, Table 5.1 reveals that it has a base case IRR of 16 per cent. This is just above the critical level, thereby justifying the decision to proceed with its development. However, the IRRs calculated under the three other scenarios considered in Table 5.1 — i.e., no fiscal relaxation (but existing technology); no new technology (but actual fiscal arrangements); and the absence of *both* fiscal change *and* new technology) — are all *below* the target of 15 per cent. This suggests that it has been the *interaction* between new technology and the relaxation in the fiscal regime that sparked Strathspey's development.[5] A similar story is true for Duncan and Innes.

The Ivanhoe/Rob Roy fields (which are treated as a single development in the cash flow analysis) represent a slightly different case. The model suggests that the target IRR would be achieved by *either* the fiscal relaxation *or* cost-saving new technology. Both effects give IRRs above the target level. However, in the absence of *both* effects (i.e., if the development involved a conventional production platform *and* the fields did not benefit from the taxation changes made in 1983 and 1993), the development would not have been attractive, assuming a 15 per cent target IRR.

Fields whose Development has been Triggered solely by the Fiscal Changes of 1983 and 1993

In Chapter 3, it was established that the fiscal changes of 1983 and 1993 were influential in triggering the development of seven fields within *The New Fields* category (see Table 3.2 in that chapter). One of these fields was Strathspey. It has been established above, that, in the case of this field, its development hinged on the *interaction* between the fiscal changes and new technology. In other words, the fiscal changes *alone* would not be sufficient to give an IRR in excess of 15 per cent.

However, for the *other* six fields included in Table 3.2 — Alba, Brae East, Bruce, Dunbar,[6] Eider and Miller — the model suggests that their development has been triggered *solely* as a result of the fiscal relaxation of 1983 and 1993. Put another way, without the fiscal changes (but with existing technology), the model estimates IRRs of below 15 per cent (as shown by the third column of Table 5.1), whereas *with* the fiscal reforms (and with existing technology) — which represents the base case — the IRRs exceed the development criterion. Indeed, in the cases of these six fields, the model indicates that new technology *cannot* have played a role in their development because they are all developed by means of production platforms, and so their costs are never adjusted in the cash flow analysis to model the impact of cost-saving technology.

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[5] Whilst it is not possible to disentangle completely the fiscal and technology effects in this case, it is possible to gauge the relative importance of the two factors by looking at the magnitudes of the IRRs presented in the final two columns of Table 5.1. The impact of new technology is clearly stronger since, in the absence of cost-saving technology (but assuming actual fiscal arrangements), the model suggests the IRR of Strathspey would fall to as low as 5.2 per cent, whilst if the fiscal changes of 1983 and 1993 had not occurred, but costs reflected existing technology the IRR would only drop to 11.9 per cent.

[6] Unlike the other fields listed in Table 3.2, Dunbar received Annex B approval *before* the fiscal changes of 1983 were announced. Thus, it would be strictly incorrect to suggest that the fiscal changes *triggered* the development of this field. Nevertheless, the model suggests that, without the fiscal changes, Dunbar would not achieve the target IRR of 15 per cent. In other words, the economic viability of Dunbar has been justified by the relaxation of the fiscal regime, and so it seems reasonable to include this field as one whose development has been triggered by fiscal factors.

Fields whose Development has been Triggered solely by Cost-Saving New Technology

As seen in Chapter 4, there are a large number of fields (listed in Table 4.1) for which the model suggests that the improvement in cash flows arising from cost-saving new technology has been influential in explaining their development. These include Strathspey, Duncan and Innes. However, as discussed above, the model suggests that the development of these three fields has been conditional on the *combination* of *both* new technology and fiscal relaxation. In other words, cost-saving technology in the absence of the 1983 and 1993 fiscal changes would not be sufficient to result in an IRR of above 15 per cent for these fields.

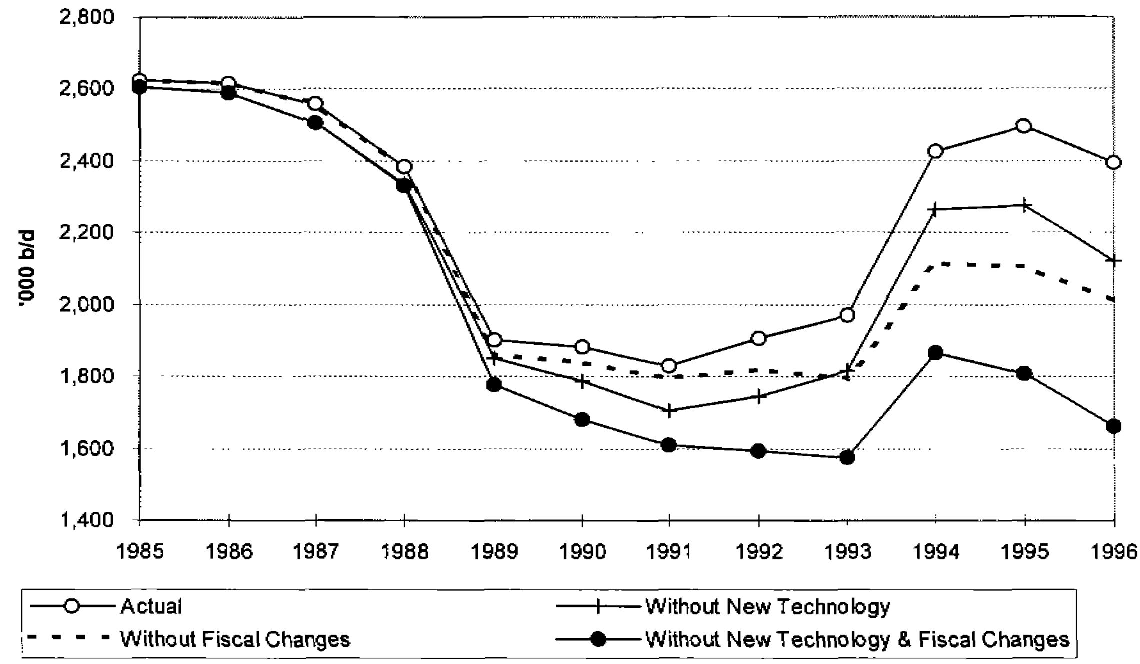
To establish that cost-saving technology *alone* has been responsible for precipitating the development of fields, it is necessary for the IRR presented in the third column of Table 5.1 (which assumes new technology but no fiscal reform) to be *higher* than the critical rate of 15 per cent, whilst it will be *below* this figure in the final column of the table (which models the impact of no new production techniques, but where the fiscal changes have taken place). This applies to all the other fields listed in Table 5.1, which are therefore assumed to have developed *solely* as a result of new technology. These fields are Amethyst, Angus, Arbroath, Argyll, Beinn, Birch, Blenheim, Chanter, Columba D, Deveron, Donan, Ellon, Fife, Glamis, Leven, Medwin, Moira, Ness, Osprey, Pelican, Petronella and Scapa.

IMPACT ON PRODUCTION

Taking into account the analysis presented in this chapter, Diagram 5.1 attempts to illustrate the relative importance of fiscal changes and new technology on UK North Sea oil production since 1985. There are four lines depicted in the diagram:

- the actual evolution of production;
- the production profile if we exclude those fields whose development has been determined to have been triggered solely by the main fiscal changes of 1983 and 1993;
- the production profile if we exclude those fields whose development has been determined to have been triggered solely by cost-saving new technology; and
- the production profile if *neither* new technology nor the 1983 and 1993 fiscal changes had occurred.

Diagram 5.1: UK North Sea Oil Production under Different Scenarios



The diagram demonstrates that, in the absence of both new technology and the key fiscal changes, UK oil output from the North Sea would have been approximately 250,000 b/d lower than actual levels in 1991 (the year of 'trough' production), and 720,000 b/d lower in 1995 (which represents the second peak in output).

Although, according to the model, the impact of new technology has triggered the development of a great number of fields, many of these represent small developments, which has muted the impact of new technology on production levels. Without new technology, the model suggests that UK North Sea production would have been around 120,000 b/d below the level actually achieved in 1991, and almost 220,000 b/d lower than actual 1995 output.[7] The fiscal changes appear to have had a stronger impact on output as the 1990s have progressed. Even though the development of a relatively small number of fields can be ascribed to fiscal changes, some of the fields in question are relatively productive. From a modest 35,000 b/d in 1991, it is estimated that without the key fiscal changes of 1983 and 1993, oil production from the UK North Sea would be lower than actual levels to the tune of approximately 400,000 b/d in 1995 and 1996.

It should be noted that Diagram 5.1 has made no allowance for the output of those fields — listed in Table 5.2 — whose development cannot be explained by the model assuming a target IRR of 15 per cent. Combined production from these fields represented close to 200,000 b/d of the UK North Sea total in 1991, rising to almost 300,000 b/d (or around 12 per cent of the total) by 1995. Table 5.3 presents the breakdown of UK North Sea

[7] It should be noted that this does not take into account the impact of new technology on the established fields. This issue is discussed in Chapters 4 and 6.

oil output in 1991 and 1995 by type of effect, and distinguishing between *The 1985 Group* and *The New Fields*.

In addition, Table 5.3 illustrates that production from *The New Fields* that would have been developed even in the absence of both cost-saving new technology and the fiscal changes contributed 35,000 b/d in 1991. This figure rose to 450,000 b/d in 1995. Of this total, Harding, Hudson, and Nelson — which were all discovered after 1985 — accounted for 230,000 b/d.

A closer inspection of the data indicates that a sizeable proportion of the increase in production during the 1990s can be explained by just two fields: Scott and Nelson. Between them, these fields (which would have been developed in the absence of new technology and the fiscal changes) accounted for 14 per cent of total production in 1995, and have been responsible for over half of the overall increase in UK oil supplies from the North Sea between 1991 and 1995.

Table 5.3: Composition of UK North Sea Oil Production in 1991 and 1995[1], by Type of Effects

	------ 1991 ------		------ 1995 ------	
	'000 b/d	% Share of Total Production	'000 b/d	% Share of Total Production
The 1985 Group	1,389	76%	1,077	43%
The New Fields	440	24%	1,417	57%
Total UK North Sea Oil Production	**1,829**	**100%**	**2,494**	**100%**
Breakdown				
The 1985 Group	***1,389***	***76%***	***1,077***	***43%***
of which:				
Fields developed as a result of new technology only	31	2%	18	1%
Fields developed as a result of combination of fiscal changes and new technology	1	-	-	-
Conventional fields	1,357	74%	1,059	42%
The New Fields	***440***	***24%***	***1,417***	***57%***
of which:				
Fields developed as a result of fiscal changes only	35	2%	390	16%
Fields developed as a result of new technology only	92	5%	201	8%
Fields developed by either or combination of fiscal changes or/and new technology	64	3%	77	3%
Fields that would have been developed anyway	53	3%	450	18%
(of which: Nelson and Scott)	(-)	(-)	(346)	(12%)
Fields developed despite actual IRRs of below 15%	196	11%	299	12%

Note:

1. 1991 is chosen because it represents the year of 'trough' production; 1995 is chosen because it represents the year of the second production peak.

In the final chapter of this study, the implications of these results for total recoverable reserves, gross revenues from the UK North Sea sector, government tax take, and oil companies' cashflows are considered. The implications of choosing different target IRRs are also examined.

Chapter 6: The Impact of Fiscal Changes and New Technology on Reserves and Financial Indicators

This final chapter examines further aspects of the impact of fiscal relaxation and new technology on the UK North Sea oil sector. In Chapter 5, the influence of these factors on the profile of UK oil production over the past decade was presented. In this chapter, consideration is given to the role played by fiscal reform and new technology on the size of the UK North Sea *reserve base*. The sensitivity of the results to different assumptions about the target IRR is addressed.

This chapter also studies the *financial implications* associated with different fiscal and technology scenarios, including an assessment of how successful the UK government has been in stimulating activity in the UK North Sea oil sector through modifications to the fiscal regime.

The first part of this chapter considers *The New Fields* and those members of *The 1985 Group* of fields that are exploited by non-conventional means and whose cash flows were influenced by the tax changes announced in the 1983 Budget. The impact of the fiscal changes and cost-saving technology on established fields is then examined, enabling conclusions to be made about the implications of these factors on the UK North Sea oil sector as a whole.

FORTHCOMING ADDITIONAL RESERVES SINCE 1985 AT DIFFERENT TARGET IRRS UNDER THE VARIOUS SCENARIOS

The aim of this section is to examine the impact of the fiscal and technology scenarios described in previous chapters on additions to the *reserve base* of the UK North Sea oil sector since 1985. In other words, the roles played by fiscal changes and new technology in the decision to develop the fields included in the cash flow analysis[1] are assessed. Consideration is also given to the importance of those fields which are judged to be economically viable even in the absence of new technology and the fiscal changes.

In Chapters 3 to 5, it is assumed that an oilfield must achieve a target IRR of 15 per cent before the decision is taken to proceed with its development. Whilst evidence from the industry suggests that a discount rate of 15 per cent is reasonable, the appropriate target IRR in reality will *vary* between operators and between the type of project involved. (For instance, a risky development is likely to be evaluated with a higher discount rate than a venture with a more certain outcome.) Therefore, to avoid over-reliance on the assumption of a 15 per cent target IRR, this section presents results over a *range* of target IRRs.

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[1] Remember that these are all the fields belonging to *The New Fields* category (i.e., those that came on stream after 1985), plus Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa from *The 1985 Group* of fields.

Table 6.1: Range of Forthcoming Additional Reserves under Different Scenarios at Target IRRs of 10%, 15% and 20%.[1] Million Barrels of Oil Equivalent

	IRR is 20%	IRR is 15%	IRR is 10%
Base Case	2,106	5,569	6,636
Without Fiscal Changes [2]	1,505	3,100	6,612
Without New Technology [3]	857	4,204	5,562
Without Fiscal Changes and New Technology	282	1,731	5,467

Notes:

1. See footnote 1 on page 65.

2. Reveals reserves which would be forthcoming from fields that would be developed in the absence of the main fiscal changes of 1983 and 1993 but with existing technology.

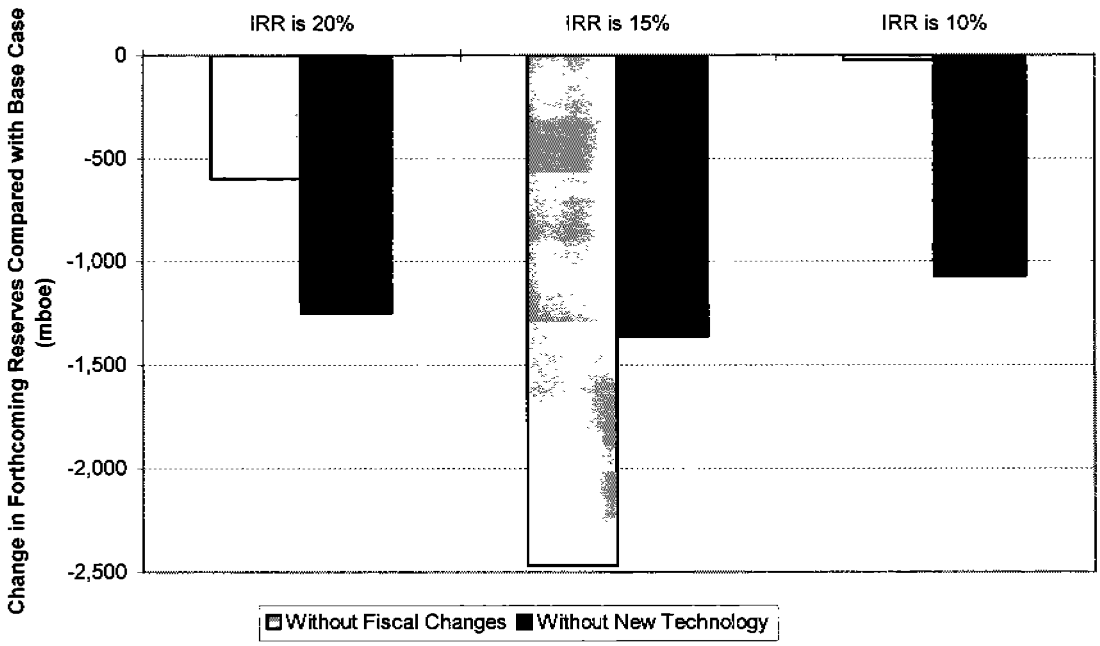
3. Reveals reserves which would be forthcoming from fields that would be developed in the absence of cost-saving new technology but assuming actual fiscal arrangements.

To highlight the differences between the different fiscal and technology scenarios, Table 6.1 (which summarizes the results of analysis contained in Annex 5.1) presents *ranges* of forthcoming reserves in each case for three target IRRs: 10, 15 and 20 per cent. From these results, the following conclusions can be drawn:

- Because a large number of fields have IRRs of between 10 and 20 per cent, the choice of the target IRR makes a significant difference to the reserves forthcoming under each of the scenarios, including the base case. For example, in the case of the scenarios involving the fiscal changes, over 5 billion more barrels of oil equivalent would be forthcoming at a target IRR of 10 per cent than if 20 per cent was chosen.

- The choice of the target IRR is also crucial in determining the relative strengths of the fiscal and technology effects, as Diagram 6.1 illustrates. For each of the target IRRs, the diagram summarizes the change in recoverable reserves that the model suggests would be forthcoming, compared to the base case, without the fiscal changes and new technology. The diagram reveals that the technology effect is relatively important whatever target IRR is chosen, accounting for over 1 billion barrels of forthcoming reserves in each case. By contrast, the importance of the fiscal changes only appears significant when the target IRR is 15 per cent. At this target rate, almost 2.5 billion barrels of oil equivalent are forthcoming as a result of the fiscal effect. However, at a target rate of 20 per cent, the corresponding figure is little more than 0.5 billion barrels, while at a target rate of 10 per cent, the model suggests that the fiscal changes would have had very little impact on the volume of new oil reserves forthcoming. From a policy point of view, this suggests that if the government had misjudged the target IRR, then its key oil taxation reforms would have been largely ineffective in encouraging the exploitation of new oil reserves in the UK North Sea sector. As it is, it could be argued that the model underlines the effective targeting of the fiscal regime, with the government correctly identifying that the target IRR used by operators is in the region of 15 per cent.

Diagram 6.1: Sensitivity of Fiscal and Technology Scenarios to the Choice of Target IRR



- Even without fiscal and technology changes, the model suggests some fields would still be economically viable, with approximately 1.7 billion barrels of oil equivalent forthcoming at a target IRR of 15 per cent, the mid-point of the range. (The corresponding figures are 0.3 billion barrels of oil equivalent at a target rate of 20 per cent and 5.5 billion barrels at 10 per cent.)

FINANCIAL IMPLICATIONS

In the section above, consideration was given to additions to the UK North Sea *reserve base* under different scenarios and at various target IRRs. In this section, the analysis is extended further by studying the *financial implications* of the different scenarios. Once again, the fields included in this analysis are all those within *The New Fields* and the seven members of *The 1985 Group* that use non-conventional production techniques: Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa.

The following financial variables (which are all expressed in money-of-the-day terms) are considered:

- *Gross Revenues:* total receipts from the sale of oil and (if applicable) gas over the lifetime of the field;
- *Government Tax Take:* the total tax bill of the fields over their lifetimes;
- *Total Costs:* the total operating and capital costs incurred by the fields over their lifetimes;
- *Investment:* which is defined as total capital costs excluding abandonment costs;
- *Company Cashflow:* this measures oil companies' profits and is calculated as gross revenues less total taxes and total costs;
- *Total Contribution to Company and Government Finance:* this is a measure of the net income generated by the UK North Sea oil industry; it is defined as government tax take plus company cash flow.

As before, the results of four scenarios are presented. A target IRR of 15 per cent is assumed for this analysis:

The Base Case: this represents the existing situation, and takes into account the cash flows of all the fields within *The New Fields* category and the seven aforementioned members of *The 1985 Group* that have actually been developed.

Without Fiscal Changes: This scenario only takes into account the cash flows of those fields that would meet the target IRR even if the key fiscal changes of 1983 and 1993 (i.e., abolition of royalty, doubling of the oil allowance, and the reduction/elimination of PRT) had *not* taken place. Existing techniques of production are assumed.

Without New Technology: This scenario only includes the cash flows of those fields which would still meet the development criterion even in the absence of cost-saving production technology. (It does not, however, make any allowance for the impact of new technology on increasing the recoverable reserve base of established fields.) The actual fiscal arrangements are assumed to be in place.

Without Fiscal Changes *and* New Technology: This scenario only takes into account the cash flows of those fields that would still meet the development criterion in the absence of cost-saving production technology *and* without the fiscal changes. In other words, it indicates what each of the financial variables would have been if there had been no technological progress *and* if the main changes to the 1983 and 1993 Finance Acts had not occurred.

The implications of these scenarios for the gross revenue, government tax take, costs, company cash flows and the total contribution to company and government finance generated by the oilfields included in this analysis are detailed in Table 6.2. The percentage change in each of the variables from the existing situation (base case) is highlighted in Table 6.3. In the following paragraphs, the impact of the scenarios on each of the financial variables is examined.

Table 6.2: Financial Indicators under Different Scenarios [1] - £ million (money-of-the-day) (Assuming Target IRR of 15 per cent)

	Base Case	Without Fiscal Changes [2]	Without New Technology [3]	Without Fiscal Changes & New Technology
Gross Revenues	88,174	60,652	75,410	44,098
Government Tax Take	17,235	15,193	14,731	10,626
Total Costs	48,831	33,575	44,843	26,710
of which:				
Investment [4]	20,755	15,207	19,953	12,681
Company Cash Flow	22,108	11,884	15,835	6,762
Total Contribution to Company & Government Finance [5]	39,343	27,077	30,567	17,388

Notes:
1. The fields included in the analysis are all those belonging to *The New Fields* category plus Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa.
2. Excludes, from the base case, from cash flows of those fields that would not be developed in the absence of the main fiscal changes of 1983 and 1993 but with existing technology.
3. Excludes, from the base case, from cash flows of those fields that would not be developed in the absence of cost-saving new technology, but with actual fiscal arrangements in place.
4. Investment is defined as total capital costs excluding abandonment costs.
5. Defined as the sum of Government Tax Take and Company Cash Flow.

Table 6.3: Financial Indicators under Different Scenarios - Percentage Change from Base Case (Assuming Target IRR of 15 per cent)

	Without Fiscal Changes	Without New Technology	Without Fiscal Changes & New Technology
Gross Revenues	-31%	-14%	-50%
Government Tax Take	-12%	-15%	-38%
Total Costs	-31%	-8%	-45%
of which:			
Investment	-27%	-4%	-39%
Company Cash Flow	-46%	-28%	-69%
Total Contribution to Company & Govt. Finance	-31%	-22%	-56%

See footnotes in Table 6.2

Gross Revenue

It is estimated that, under existing fiscal and technology conditions (the base case), gross revenues generated from the fields included in this analysis are approximately £88.2 billion (as revealed in the first column of Table 6.2). Tables 6.2 and 6.3 show how revenues would change under the different fiscal and technology scenarios. Under the most extreme case — i.e., in the absence of new cost-saving technology *and* the main fiscal changes of 1983 and 1993 — the model suggests that gross revenue would fall by 50 per cent, compared with the base case, to £44.1 billion. This reflects the large number of fields that would not meet the assumed target IRR of 15 per cent under such cost and tax conditions, and therefore would not come on stream.

The other columns in the tables isolate the individual impacts of the fiscal changes and new technology. They suggest that, given the target IRR, gross revenues have been more sensitive to the fiscal changes. Without the main fiscal changes of the 1983 and 1993 Finance Acts (but with existing technology), the model indicates that gross revenue would be 31 per cent lower than the base case, at around £60.7 billion. Without new technology (but given existing fiscal arrangements), the decline in gross revenue would be less severe, at around £75.4 billion (a reduction of 15 per cent). This reiterates one of the results presented in Chapter 5: although new technology appears to have been pivotal in triggering the development of a greater *number* of new oilfields than the fiscal changes, many of the fields are small developments, and in terms of the total volume of recoverable reserves brought on stream since 1985 — and therefore on the gross revenues earned from the sale of their production — the fiscal changes account for the greater share of the increase.

Government Tax Take

In the case of the fiscal scenarios, there are two opposing forces at work. For those fields whose development is not sensitive to fiscal considerations, the relaxation of the fiscal regime in 1983 and 1993 has merely added to the *profitability* of these fields, and represents a source of potential taxation revenue that has been foregone by the government. In the absence of the fiscal changes, tax take from such fields would have been *higher*. However, an increase in the tax burden means that the IRR of a number of fields would not meet the target level, and so their development would *not* go ahead, resulting in a zero tax take from the fields concerned. This effect works to *reduce* government tax take from the base case. The figures in Tables 6.2 and 6.3 confirm that the latter effect predominates: in other words, without the fiscal changes of 1983 and 1993, overall tax take from the fields included in this analysis would be approximately £2 billion, or 13 per cent, *lower* than was actually the case (i.e., £15.2 billion compared with £17.2 billion) as a result of certain fields not coming on stream under the more restrictive tax regime. However, these figures fail to tell the whole story because they do not take into account the loss in the tax take from the established fields not included in the analysis presented in Tables 6.2 and 6.3, but which nevertheless have had their tax liability lowered as a result of the reduction in PRT from 75 to 50 per cent in the 1993 Finance Act. This issue is addressed later in the chapter.

Turning to the role of new technology, government tax take would fall to around £14.7 billion — a decline of 15 per cent compared with the base case — under existing fiscal arrangements but without new technology. This reflects the loss in tax take from the large number of fields whose development would not go ahead under such circumstances.

In the absence of *both* the fiscal changes and new technology, government tax take would be 38 per cent below its base case level.

Total Costs and Investment

Without the spread of cost-saving production technology, the cost of developing oilfields would obviously rise above current levels. However, by the very nature of this increase, the development of a number of fields — by reducing their IRRs below the trigger level — would not go ahead, which will act to *reduce* the total costs incurred and the investment undertaken in the North Sea. Indeed, as revealed in Table 6.2, the model suggests that, in the absence of new technology, the total cost bill would decline by 9 per cent from its estimated current (base case) level of £48.8 billion to £44.5 billion. This decline reflects the smaller number of fields that would come on stream if cost-saving technology was not available. In terms of investment (which is defined as total capital costs but excluding abandonment costs), the reduction is 4 per cent — from £20.8 billion under the base case to £20.0 billion if new production techniques were not available. This modest decline highlights the relatively low capital costs associated with the development of many marginal fields as a result of new production technology.

At over 30 per cent, the decline in total costs and investment under the fiscal scenario is much greater than the technology effect. This reflects the fact that some of the larger (and hence more costly) developments in recent years — fields such as Alba, Brae East, Bruce and Miller — would not have come on stream without the main fiscal changes of 1983 and 1993.

The model indicates that total costs and total investment would decline by 45 and 39 per cent, respectively, compared with the base case, if neither the fiscal changes nor advances in new technology occurred.

Company Cash Flow

This is a measure of oil company profitability and is calculated as gross revenues minus taxes and costs. The analysis indicates that, without the combined effect of cost-saving new technology and the taxation changes of 1983 and 1993, total oil company cash flow from field developments included in this analysis would amount to less than £6.8 billion — a hefty 69 per cent decline compared with the existing situation.

Once again, by isolating the fiscal, technology and recent discovery effects, it appears that fiscal factors would account for the bulk of this change. Without the fiscal changes (but with existing technology), the model estimates that company cash flows would be £11.9 billion. Under current fiscal arrangements, but in the absence of the new technology, the equivalent figure would be close to £15.8 billion.

Total Contribution to Company and Government Finance

The final financial indicator monitored in Tables 6.2 and 6.3 is termed the 'total contribution to company and government finance', and is defined as government tax take plus company cash flow arising from the production activities of the North Sea oilfields included in this analysis. Under the base case, the total contribution to company and government finance is estimated at approximately £39.3 billion. Assuming a target IRR of 15 per cent, the total contribution to company and government finance would fall to £17.4 billion — a decline of 56 per cent — in the absence of both fiscal changes *and* technological progress.

Once again, at the chosen IRR, the fiscal effect appears to have the greater impact on this financial indicator. Without the key fiscal changes of 1983 and 1993 (but with existing technology), the analysis suggests that the total contribution to company and government finance would fall to £27.1 billion, whereas if the technology effect is isolated, the decline in the total contribution to company and government finance would be more modest — from £39.3 to £30.6 billion.

Summary of the Financial Implications of the Fiscal and Technology Scenarios

The following conclusions arise from the financial analysis presented above:

- Together, fiscal relaxation and cost-saving technology have had an important influence on revenues generated from the UK North Sea since 1985. In the absence of new technology *and* the key fiscal changes of 1983 and 1993:
  - gross revenues from the fields included in this analysis would be 50 per cent lower than is currently the case;
  - total tax take would be 38 per cent lower;
  - investment would be reduced by almost 40 per cent; and
  - company cash flow would be 56 per cent lower than under the base case.
- At a target IRR of 15 per cent, the fiscal scenario has the greatest impact on the financial indicators. Without the key fiscal changes of 1983 and 1993, gross revenue, investment and the total contribution to company and government finance from the fields included in the analysis would all fall by around 30 per cent, compared with the base case, with company cash flow declining by almost 50 per cent.

- The financial indicators would fall more modestly in the absence of new technology (but with the existing fiscal arrangements), reflecting the small nature of the field developments that would be affected.

- The least sensitive financial indicator, in terms of fluctuations from the base case, is government tax take. Without new technology (but with existing fiscal arrangements and including fields discovered after 1985), the loss in tax take would be just 15 per cent assuming a target IRR of 15 per cent. This modest fall reflects the fact that the vast majority of the fields that would not be developed under these conditions are small ventures, with limited tax liability. The decline in government tax take would be even less dramatic (albeit slightly, at 12 per cent) under the assumption that the fiscal changes did not occur. This is because the increase in tax take from the fields that would still be developed (which include significant producers such as Nelson and Scott) would *partially offset* the loss in tax revenue from those fields whose development *is* sensitive to the fiscal measures, and would therefore not come on stream unless the fiscal changes of 1983 and 1993 had occurred.

- The most sensitive indicator is company cash flow. In the case of the fiscal effect, for example, it would decline by as much as 46 per cent in the absence of the 1983 and 1993 fiscal changes. This emphasizes the profitability (in cash terms) of fields such as Alba, Brae East, Bruce and Miller, which are some of the larger fields to have come on stream during recent years, and whose development is judged by the model to have been triggered by fiscal measures.

TAKING THE ESTABLISHED FIELDS INTO ACCOUNT

It should be remembered that the fields included in the analysis presented thus far in this chapter are all those that came on stream after 1985 (*The New Fields*) and the seven members of *The 1985 Group* — Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa — that are exploited by non-conventional means. As such, the forthcoming reserves presented in Table 6.1 represent *additional* reserves to those already coming on stream from the established fields (i.e., all other members of *The 1985 Group*), which started production in the 1970s or early 1980s.

Similarly, the financial implications analysis presented in Tables 6.2 and 6.3 takes no account of the gross revenue, government tax take and investment generated from the established fields. Thus, to present a picture of the UK North Sea sector *as a whole*, the impact of new technology and fiscal changes on the established fields is now considered briefly.

During the course of the analysis presented in this study, it is assumed that the decision to develop the established fields has been taken independently of technological and fiscal factors. This is because these fields are all exploited by production platforms, and they all received Annex B approval *before* the 1983 and 1993 Finance Acts. Nevertheless, changes to the fiscal regime and technological advances have had some impact on the established fields. For example:

> **Change in Tax Take:** In the 1993 Budget, the rate of PRT paid by all fields with Annex B approval before 16 March 1993 was reduced from 75 to 50 per cent. This has the effect of lowering the government tax take from established fields, and boosting their cash flows.
>
> **Technology-Induced Reserve Increases:** As discussed in Chapter 4, estimates of recoverable reserves from many of the established fields have been upgraded because of the reclassification of some of the original oil-in-place from uneconomic to economically recoverable as the result of technology-induced cost reductions.

Measuring the Change in Tax Take

Recall that the analysis presented in Tables 6.2 and 6.3 indicates that, without the fiscal changes of 1983 and 1993, overall tax take from *The New Fields* and the seven 'non-conventional' members of *The 1985 Group* would be approximately £2 billion *lower* than is actually the case, as a result of certain fields not coming on stream under the more restrictive tax regime. This led to the conclusion that the relaxation of the fiscal regime resulted in an *increase* in government tax take. However, these figures do not take account of the loss in the tax take from the *established* fields as a result of the reduction in the rate of PRT from 75 to 50 per cent in the 1993 Finance Act. In this section, an attempt is made to quantify this loss in order to estimate the *net* effect for government tax take for the UK North Sea as a whole. Rather than undertake the time-consuming task of preparing individual cash flow analyses for each of the established fields, a simplified approach has been adopted to make this estimate, and is presented in Annex 5.2.

Table A5.1 in Annex 5.2 suggests that, in total (and when calculated over their expected lifespans), the government sacrificed £5.3 billion in tax revenue from the established fields when it reduced the rate of PRT from 75 to 50 per cent. This is more than sufficient to offset the £2 billion *additional* tax take that is calculated to be collected from those new fields whose development is deemed to have been due to the 1983 and 1993 fiscal changes. So the model suggests that the *net* effect on government tax take as a result of the relaxation of the fiscal regime is a *loss* of around £3.3 billion (as calculated in Table 6.4).

Table 6.4: Net Change in Government Tax Take as a Result of the 1983 and 1993 Fiscal Changes. £ million

Government Tax Take From *The New Fields* & Non-Conventional Fields from *The 1985 Group* [1]	
Base Case	17,235
Without Fiscal Changes	15,193
Increase as a Result of the Fiscal Changes	**+ 2,042**
Tax Sacrificed from the Established Fields as a Result of Fiscal Changes [2,3]	**- 5,323**
NET CHANGE IN GOVERNMENT TAX TAKE	**-3,281**

Notes:
1. The non-conventional fields in *The 1985 Group* are Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa.
2. Established fields are all other members of *The 1985 Group*.
3. See Annex 5.2 for details of how this is calculated.

However, this loss should be viewed in the context of the extra reserves brought on stream as a result of the fiscal changes, as well as additions to gross revenues, investment, company cash flow and total contribution to company and government finance. These are detailed in Table 6.5, which summarizes how recoverable reserves and financial indicators for the UK North Sea as a whole have been influenced by the main fiscal changes of 1983 and 1993, taking into account the loss in tax take from the established fields over their expected lifespans as a result of the reduction in PRT to 50 per cent. The government has apparently sacrificed around £3.2 billion in terms of lower tax take than would have been the case without the reduction in the rate of PRT. In return, additional gross revenues of nearly £27.5 billion have been generated; investment in the UK North Sea sector has been boosted by £5.5 billion; company cash flow is up by nearly £10.2 billion; and there has been a £6.9 billion addition to the total contribution to company and government finance.

Table 6.5: Change in Financial Indicators and Recoverable Reserves as a Result of the Fiscal Changes of 1983 and 1993 - All Fields (Assuming Target IRR of 15 per cent). (£ million)

Recoverable Reserves (mboe)	2,469
Gross Revenue	27,522
Government Tax Take [1]	- 3,281
Investment	5,548
Company Cash Flow	10,224
Total Contribution to Company & Govt. Finance	6,943

Note: 1. See Table 6.4 for calculation. Note that no allowance has been made for the increase in government tax revenue as a result of abolishing PRT relief on exploration and appraisal drilling in the 1993 Finance Act.

PRT Relief for Exploration and Appraisal Expenditure

However, even this is not the full story because the cash flow model does not take into account the tax revenue saved by the government when it decided — and included in the 1993 Budget — to abolish PRT rebates for exploration and appraisal expenditure. Meanwhile, the elimination of the Cross Field Allowance (whereby up to 10 per cent of qualifying development expenditure of new fields can be offset against a company's PRT liability of other fields) also resulted in a boost to government tax revenues, although the effect was minor in comparison to the exploration and appraisal expenditure tax breaks.

Indeed, in the years leading up to the 1993 Budget, exploration and appraisal expenditure was the main eligible cost in reducing the government's PRT yield, with Wood Mackenzie (North Sea Service, March 1993) estimating that this form of PRT tax relief reduced government coffers by over £680 million a year. After it announced its 1993 Budget proposals, the UK Treasury claimed that its reform of the oil fiscal regime would result in an overall *increase* in tax yield of some £700 million by 1995/96. This suggests that the tax revenue generated by the government by removing PRT tax reliefs on exploration and appraisal expenditure (which is not picked up in our model) more than offset the tax sacrificed by lowering the rate of PRT from 75 to 50 per cent for established fields.

Nevertheless, the 1993 fiscal reforms proved to be very controversial at the time they were introduced, with many in the industry arguing that the most likely casualty of the changes would be the *future* level of exploration and appraisal drilling, which is an important indicator of the *longer-term* health of the upstream sector of the UK North Sea. Whether or not these fears are justified is a moot point. The evidence currently available is inconclusive. As Diagram 2.3 (in Chapter 2) illustrates, the number of exploration and appraisal drills spudded did record year-on-year declines in 1993, 1994 and 1995. However, a downward trend was already evident at the beginning of the 1990s — i.e., *ahead* of the decision to abolish PRT reliefs on exploration and appraisal drilling. The *rate* of decline in drilling activity actually *slowed down* after the 1993 Budget. Moreover, 1996 saw a recovery in exploration and appraisal drilling, which exceeded one hundred well starts, and a further increase is being forecast for 1997.

Incorporating Technology-Induced Reserve Increases

At the beginning of this chapter, Table 6.1 highlighted the reserves forthcoming from *The New Fields* and the seven non-conventional members of *The 1985 Group* as a result of the different fiscal and technology scenarios. In this section, the analysis is extended to include the reserves of the established fields.[2] In the case of the scenarios involving new technology, this means taking into account the impact of improved oil recovery techniques on estimates of recoverable reserves of the established fields. This issue was explored in Chapter 4, when the technology-induced increase in reserves was estimated for each of the fields in *The 1985 Group* (see Table 4.2).

To see how the inclusion of the established fields affects the results, Table 6.6 reveals, separately, the forthcoming additional reserves from *The New Fields*, assuming a target IRR of 15 per cent (which are figures taken from Table 6.1) and forthcoming reserves from *all* the UK North Sea fields. This includes the reserves from the established fields and takes into account the impact of technology-induced increases.

Table 6.6: Forthcoming Reserves under Different Scenarios - Incorporating the Established Fields (Assuming Target IRR of 15 per cent). Million Barrels of Oil Equivalent

	Base Case	Without Fiscal Changes	Without New Technology [1]	Without Fiscal Changes & New Technology [1]
The New Fields [2]				
Forthcoming Reserves	5,569	3,100	4,204	1,731
Loss in Reserves [3]		*2,469*	*1,365*	*3,838*
All Fields [4]				
Forthcoming Reserves	21,575	19,106	17,612	15,139
Loss in Reserves [3]		*2,469*	*3,963*	*6,436*

Notes:
1. Including the impact of technology-induced increase in reserves of established fields.
2. Includes the non-conventional fields from *The 1985 Group*: Argyll, Buchan, Deveron, Duncan. Highlander, Innes and Scapa.
3. Compared to the base case.
4. Includes all members of *The 1985 Group* and *The New Fields*.

As far as the overall level of reserves is concerned, the base case of 21.6 billion barrels of oil equivalent represents the total recoverable reserves from all the established fields that have actually come on stream plus the reserves from those members of *The New Fields* that meet the target IRR. The other columns in the table indicate how these estimates would change in the absence of either, or all, of the fiscal, technology and economically-robust recent discovery effects. These results suggest that:

[2] The analysis is confined to a study of the *quantities* of recoverable reserves that are forthcoming. The *financial implications* of the increase in reserves are *not* considered in detail here. An increase in recoverable reserves would obviously boost a field's gross revenues, which, in turn, would result in a rise in government tax take. Company cash flows would also rise. Furthermore, the increase in reserves may encourage operators to engage in secondary recovery techniques, thereby increasing investment.

- In the absence of both new technology and the relaxation of the fiscal regime in 1983 and 1993, recoverable reserves from the UK North Sea as a whole would be almost 6.4 billion barrels lower than the base case. If, in addition, fields discovered after 1985 are excluded, reserves would be almost 7.2 billion barrels lower.

- Once technology-induced increases in reserves of established fields are taken into account, and assuming a target IRR of 15 per cent, the recoverable reserves that would be forthcoming in the absence of new technology (but with existing fiscal arrangements and including the fields discovered after 1985) would be around 17.6 billion barrels of oil equivalent. This is almost 4.0 billion barrels less than the base case. Without the fiscal changes (but with existing technology), the loss would be lower, at less than 2.5 billion barrels.

- Thus, taking into account the impact of technology-induced reserve increases of the established fields, the technology effect is stronger than the fiscal effect at a target IRR of 15 per cent. In other words, the reserves that have been brought into production as a result of technological advances *exceed* those that would have been brought on stream as a result of the fiscal changes of 1983 and 1993. (Recall that, at this target IRR, the relative strength of the two effects is reversed if established fields are excluded from the analysis, as the upper rows in Table 6.6 confirm.)

SUMMARY POINTS

- The large number of new fields that have come on stream in recent years have underpinned the upturn in UK North Sea oil production since 1991. Many of these new fields are small developments that are traditionally considered very marginal from an economic point of view. However, factors such as new technology and a relaxation of the UK fiscal regime have boosted the attractiveness of developing such fields.

- A model based on the cash flows of *The New Fields* and those seven members of *The 1985 Group* that are exploited by non-conventional methods can be used to judge whether the decision to develop fields has been due to the impact of fiscal changes or to advances in production technology.

- In the case of fiscal changes, the model estimates what the internal rate of return of fields would have been if the main changes in the Finance Acts of 1983 and 1993 had *not* taken place — i.e., all fields are subject to royalty of 12.5 per cent; the oil allowance of fields with Annex B after April 1982 is *not* doubled; and the rate of PRT remains at 75 per cent after 1983 for all fields (including those with Annex B approval after 16 March 1993).

- The role of new technology is assessed by re-calculating IRRs of fields on the basis that all costs are adjusted to reflect the situation if fields are exploited by means of a conventional fixed production platform.

- A factor to be considered in explaining the *timing* of certain oilfield developments is the date of discovery. Of the fields that the model suggests would still meet the target IRR of 15 per cent in the absence of both new technology and the main fiscal changes, three — Harding, Hudson and (significantly) Nelson — were discovered after 1985.

- In terms of estimating the volume of additional oil reserves forthcoming as a result of fiscal relaxation and cost-saving new technology, the choice of the target IRR is important. Assuming a target rate of 15 per cent, the model suggests that, in the absence of new technology, the changes to the UK fiscal regime, and excluding fields discovered after 1985, less than 1 billion barrels of oil equivalent would have been forthcoming from the fields included in the analysis — which is nearly 4.6 billion barrels less than the base case.

- Given a target IRR of 15 per cent, the fiscal effect is the dominant scenario. Without the 1983 and 1993 fiscal changes (but with existing technology and including all fields discovered after 1985), the model suggests that 3.1 billion barrels of oil would be forthcoming. This is nearly 1 billion barrels lower than the corresponding figure under the technology effect.

- Financial indicators such as gross revenues, government tax take, investment and company cash flow from the fields included in the analysis (i.e., *The New Fields* and the seven non-conventional members of *The 1985 Group*) are also more sensitive to fiscal changes than to the technology effect (assuming a target IRR of 15 per cent). This is because the development of some of the more sizeable fields to have come on stream in recent years — including Alba, Brae East, Bruce and Miller — is judged to have been triggered by changes to the fiscal regime.

- However, once the impact of fiscal changes and new technology on established fields (i.e., all other members of *The 1985 Group* of fields) is taken into account, a slightly different picture emerges:

  – New technology has a more prominent impact on the volume of forthcoming reserves when improved oil recovery rates from the established fields are included in the analysis. It is estimated that, compared to the existing situation, nearly 4 billion fewer barrels of oil equivalent would come on stream in the absence of new technology (but with current fiscal arrangements), assuming a target IRR of 15 per cent. This is greater than the loss of 2.5 billion barrels of oil reserves associated with the fiscal effect (i.e., assuming current technology but that the main fiscal changes of 1983 and 1993 did not occur).

— The decision, taken in the 1993 Budget, to reduce the rate of PRT on existing fields from 75 to 50 per cent lowered the tax liability of the established fields by an estimated £4.8 billion (in money-of-the-day terms). This is more than sufficient to offset the £2 billion *additional* tax take which is calculated to be collected from new fields whose development is judged to have been dependent on the 1983 and 1993 fiscal changes. Thus, the model suggests that *net* effect on government tax take as a result of the relaxation of the fiscal regime is a loss of around £2.8 billion.

— However, the model does not take into account the savings that resulted from the decision, taken in the 1993 Budget, to abolish PRT relief for exploration and appraisal. According to estimates made by the UK Treasury, these savings more than offset any loss in tax revenue resulting from the reduction in the rate of PRT to 50 per cent. It has been argued by others that the ending of PRT relief will discourage *future* exploration and appraisal expenditure, thereby rebounding on activity in the UK North Sea sector in the years ahead. The evidence currently to hand is inconclusive: while exploration and appraisal drilling did continue to fall from 1993 until 1995, a recovery was recorded in 1996, and a further rise is predicted for 1997.

Annex 1: Size Structure of UK North Sea Oil Fields

Table A1.1: Size of UK North Sea Oil Fields in Terms of Recoverable Oil Reserves. Million Barrels

Very Small (50 or less)	Small (51- 200)	Medium (201 - 400)	Large (401 - 1000)	Very Large (More than 1000)
Amethyst	Arbroath	Alba	Brae Area	Beryl
Angus	Argyll	Alwyn North	Claymore	Brent
Beinn	Auk	Brae East	Fulmar	Forties
Birch	Balmoral	Bruce	Magnus	Ninian
Blair	Beatrice	Cormorant	Nelson	Piper
Blenheim	Buchan	Dunlin	Scott	
Chanter	Clyde	Maureen	Statfjord UK	
Columba D	Dunbar	Miller	Thistle	
Crawford	Eider	Murchison UK		
Cyrus	Gannet	Tern		
Deveron	Gryphon			
Don	Harding			
Donan	Heather			
Duncan	Highlander			
Ellon	Hudson			
Emerald	Hutton			
Everest	Ivanhoe			
Fife	Kittiwake			
Glamis	Montrose			
Hamish	NW Hutton			
Innes	Osprey			
Leven	Pelican			
Linnhe	Rob Roy			
Lomond	Saltire			
Lyell	Scapa			
Medwin	Strathspey			
Moira	Tartan			
Ness	Tiffany			
Petronella				
Staffa				
Stirling				
Toni				
Viking				

Diagram A1.1: Cumulative Oil Reserves versus Field Numbers

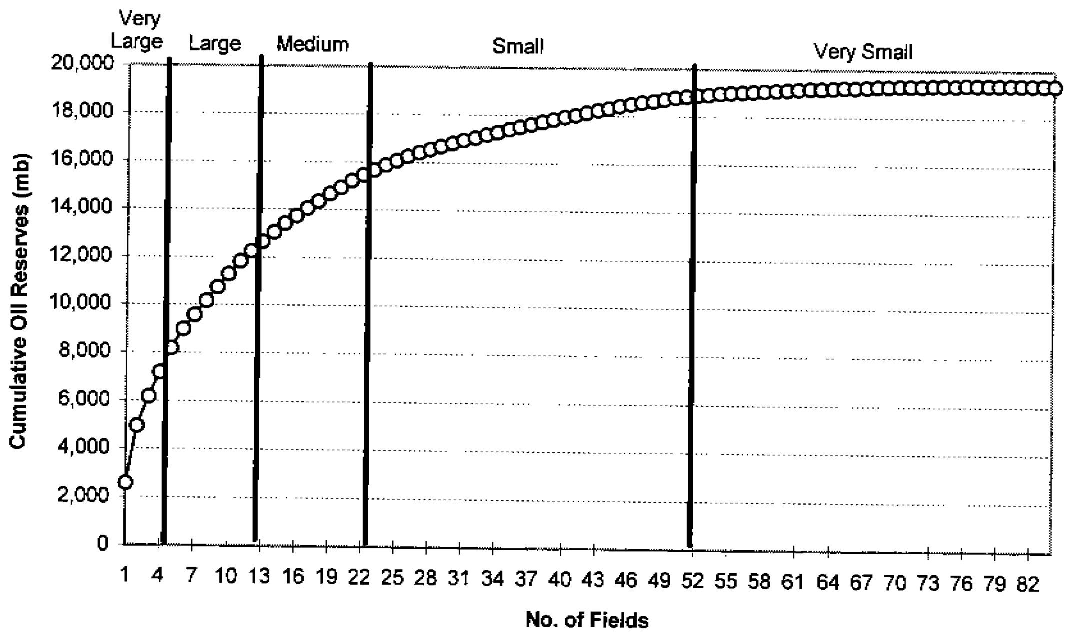


Diagram A1.2: Number of Fields by Size Category

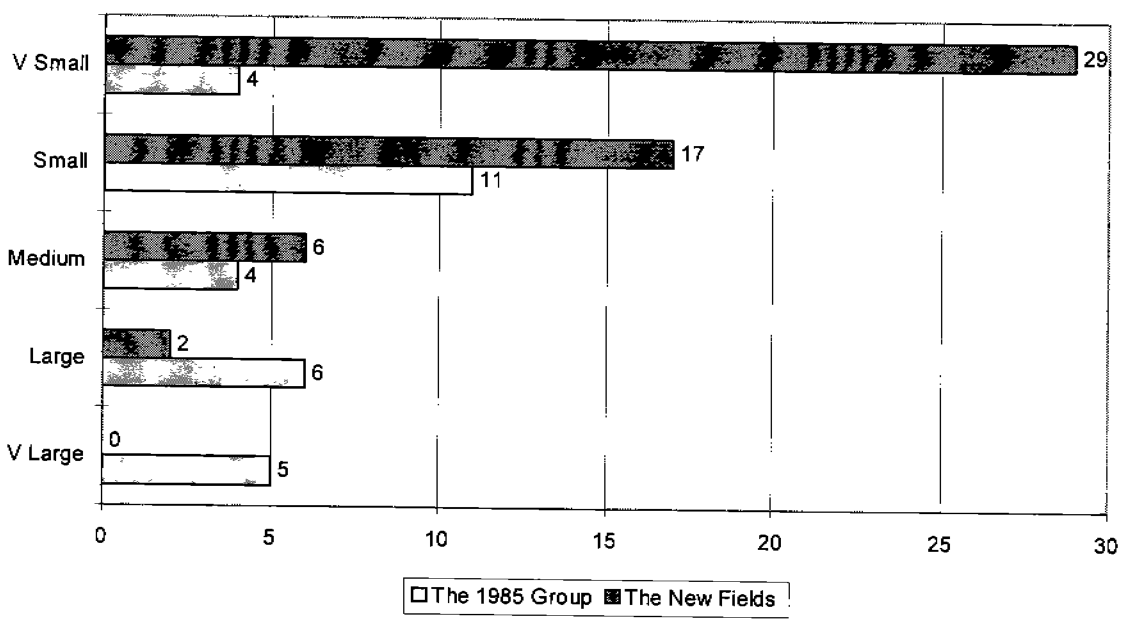


Diagram A1.3: *The 1985 Group* - Distribution of Cumulative Production Since 1985 by Size of Field

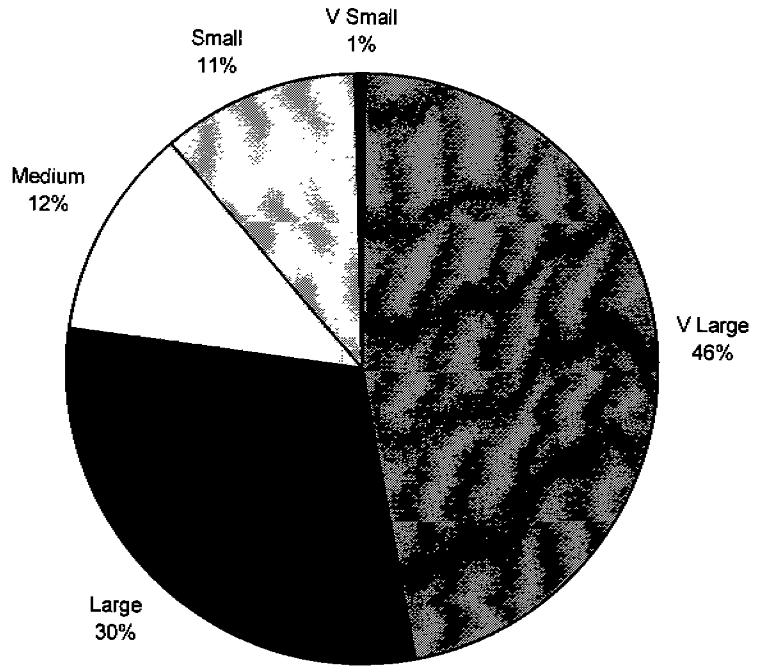
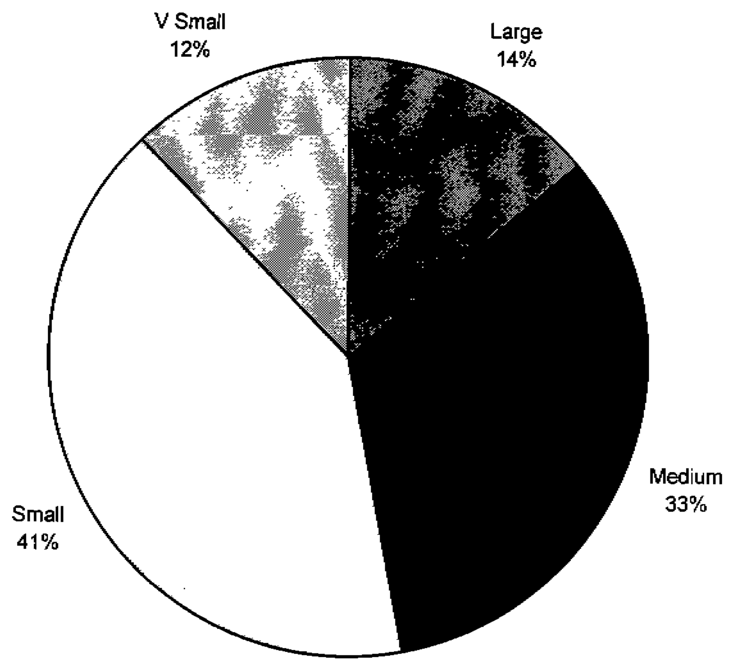


Diagram A1.4: *The New Fields* - Distribution of Cumulative Production Since 1985 by Size of Field



Annex 2: Details of UK Oil Fiscal Changes and UK Licensing Rounds

Table A2.1: Chronology of Key Changes to the UK Fiscal Regime

1975	PRT introduced at rate of 45% Concept of ring fencing introduced
1979	PRT raised to 60% Oil allowance reduced from 500,000 long tons per six-month charging period to 250,000 metric tonnes per period, with cumulative maximum reduced from 10 million long tons to 5 million metric tonnes. Reduction of uplift from 75% to 35%.
1980	PRT raised to 70%, and element of pre-payment introduced.
1981	Supplementary Petroleum Duty (SPD) of 20% introduced.
1982	SPD abolished at end of 1982, and replaced, from beginning of 1983, by Advance Petroleum Revenue Tax (APRT) to be phased out on a sliding scale from 20% in first half of 1983 to 0% by the beginning of 1987.
1983	PRT raised to 75% For oilfields with Annex B after April 1982, oil allowance is doubled to 500,000 metric tonnes each six months with a cumulative maximum of 10 million tonnes. Expenditure on exploration and appraisal drilling made eligible for PRT relief. Oilfields with Annex B after April 1982 are exempt from royalty.
1987	Cross Field Allowance introduced: for fields with Annex B approval after April 1987, up to 10% of qualifying development expenditure incurred can be offset against PRT liability of other fields.
1993	PRT reduced to 50% for existing fields; abolished for fields with Annex B approval after 16 March 1993. Expenditure on exploration and appraisal drilling no longer eligible for PRT relief.

Table A2.2: Licensing Rounds and Discovery of UK North Sea Oil Fields
(Highlighting Fields Discovered After 1985)

Licensing Round (Year)	Fields Discovered in Licensed Blocks	Year of Discovery
First (1964)	Viking	1965
	Arbroath	1969
	Amethyst 1	1970
	Montrose	1971
	Amethyst 2	1972
	Gannet A	1978
	Gannet B	1979
	Gannet C	1982
	Gannet D	***1987***
Second (1965)	Forties [1]	1970
	Argyll	1971
	Dunbar	1973
	Ellon	1973
	Alwyn North	1975
	Duncan	1981
	Everest	1982
	Innes	1983
	Nelson	***1988***
Third (1970)	Auk	1971
	Brent	1971
	Lomond	1972
	Maureen	1973
	Statfjord UK	1974
	Brae Area	1975
	Fulmar [1]	1975
	Murchison UK	1975
	Cyrus	1979
	Brae East	1980
	Strathspey	1980
	Beinn	***1987***
	Moira	***1988***

Note: [1] Represents Segregation Licence

Table A2.2 (continued): Licensing Rounds and Discovery of UK North Sea Oil Fields
(Highlighting Fields Discovered After 1985)

Licensing Round (Year)	Fields Discovered in Licensed Blocks	Year of Discovery
Fourth (1971/72)	Beryl	1972
	Cormorant	1972
	Deveron	1972
	Dunlin	1973
	Heather	1973
	Hutton	1973
	Piper	1973
	Thistle	1973
	Bruce	1974
	Buchan	1974
	Claymore [1]	1974
	Magnus	1974
	Ninian	1974
	Osprey [1]	1974
	Balmoral	1975
	Crawford	1975
	Ivanhoe	1975
	Lyell	1975
	NW Hutton	1975
	Pelican [1]	1975
	Petronella [1]	1975
	Scapa [1]	1975
	Tartan	1975
	Tern [1]	1975
	Beatrice	1976
	Don	1976
	Eider [1]	1976
	Highlander [1]	1976
	Toni	1977
	Tiffany	1979
	Columba D	1980
	Stirling	1980
	Glamis	1982
	Blair	1983
	Alba	1984
	Rob Roy	1984
	Scott	1984
	Birch	1985
	Chanter [1]	1985
	Donan	***1987***
	Hudson [1]	***1987***
	Saltire [1]	***1988***

Note: [1] Represents Segregation Licence

Table A2.2 (continued): Licensing Rounds and Discovery of UK North Sea Oil Fields
(Highlighting Fields Discovered After 1985)

Licensing Round (Year)	Fields Discovered in Licensed Blocks	Year of Discovery
Fifth (1976/77)	Clyde	1978
	Medwin	1979
	Leven	1983
Sixth (1978/79)	*none*	
Seventh (1980/81)	Emerald	1981
	Kittiwake	1981
	Miller	1983
	Staffa	1985
	Ness	***1986***
	Linnhe	***1988***
	Blenheim	***1990***
Eighth (1982/83)	*none*	
Ninth (1984/85)	***Gryphon***	***1987***
	Harding	***1988***
Tenth (1986/87)	***Hamish***	***1988***

Note: [1] Represents Segregation Licence

Source: UK Department of Trade and Industry, *The Brown Book*

Annex 3.1: Description of The Taxation Model

In an attempt to gauge the impact of the UK fiscal regime on the financial viability of individual oil fields in the North Sea, a taxation model has been devised. Distinguishing between royalties, petroleum revenue tax (PRT) and corporation tax (CT), this model estimates the tax liability for each of the fields within *The New Fields* category. By changing key parameters (such as the rate of PRT, the size of the oil allowance, and the re-introduction of royalty for fields with Annex B approval after 1 April 1982 etc.), it is possible to simulate how changes in the fiscal regime affect fields' profitability, and therefore to judge to what extent the decision to develop a field has been influenced by fiscal considerations.

As with most forms of taxation, the rules relating to many aspects of oil taxation are rather complex. Indeed, many books have been published that are devoted solely to explaining how the system works. Rather than become bogged down with the intricacies of the regime, and for practical purposes, the taxation model adopts a simplified approach. While it may not therefore rival more complex taxation models (such as the one developed by Alexander G Kemp and David Rose of the University of Aberdeen), it nevertheless includes most of the salient features of the UK fiscal regime, and gives a broad indication of the total tax liability of each of the fields under consideration.

The sequence of the different forms of taxation is: (1) royalty, (2) PRT and (3) CT. Royalty payments can be offset against profits in the calculation of PRT. In the calculation of CT, both royalty and PRT payments are offset.

The key features of the taxation model and the assumptions/simplifications that have been made are summarized in the following paragraphs:

General

The taxes have been calculated on the basis of production, cost and revenue data supplied for each field by *Wood Mackenzie* in its North Sea Service (June 1996). In its projections of revenues, Wood Mackenzie assumes an oil price of $17/barrel in 1996, rising at an annual rate of 3.0 per cent in *nominal* terms from 1997.

Taxes have been calculated *annually* on a calendar year basis. In reality, PRT is calculated by six-month periods, and CT is paid on a fiscal year (April/March) basis.

Since the purpose of the model is to determine the tax liability of an individual oil *field* rather than an individual oil *company*, no allowance is made in the model for exploration and appraisal expenditure incurred elsewhere on the UKCS (which between 1983 and 1993 could be used by a company to offset its PRT liability). Similarly, for the purposes of the model, corporation tax has been calculated on a *field* basis, whereas, in reality, it is charged on a *company* basis (making it possible for companies to offset losses from one field against profits from another). In other words, the cash flows do not reflect corporate synergies.

The Cross Field Allowance — whereby 10 per cent of qualifying developing expenditure on fields receiving Annex B approval after April 1987 can be offset against the PRT liability of other fields — has *not* been included in the model.

Royalty

Basis of Calculation

For fields that were granted Annex B approval before April 1982, royalty is calculated on the basis of 12.5 per cent of the revenues generated by the field. However, certain costs can be offset against gross revenues before the royalty calculation is made. Thus, in practice, the 'effective' rate of royalty is lower than 12.5 per cent of gross revenues. Indeed, the average 'effective' rate for those members of *The 1985 Group* liable to pay royalty differs enormously, ranging from around 5 per cent in the case of the Hutton field, to approximately 11 per cent for Piper.

Fields with Annex B approval after 1 April 1982 are exempt from paying royalty. This includes all the fields within *The New Fields* category.

Petroleum Revenue Tax (PRT)

Basis of Calculation

No PRT is levied until accumulated capital expenditure plus uplift (explained below) has been completely written off. (This is termed 'payback' and is discussed in greater detail below.)

PRT is assessed on 'assessable profit' which is defined as gross revenues minus a series of deductions: royalty payments, operating costs and allowable capital expenditure (including uplift, where applicable). Losses incurred on the fields can be brought forward or carried back and are deducted from the 'assessable profit' figure. A final deduction is the cash equivalent of the oil allowance (explained below). The resultant figure is termed 'chargeable profit' and has PRT levied on it.

Safeguard

To encourage marginal developments, there is a limit known as 'safeguard' on the amount of PRT payable by a field. This applies until the field has reached payback plus half the number of periods taken to reach payback (rounded up to a whole number of periods, where necessary). Safeguard is calculated on the basis of an 'adjusted profit' figure, which is defined broadly as gross revenues minus royalty payment and operating costs. PRT liability is limited to being no greater than 80 per cent of the amount by which the adjusted profit exceeds 15 per cent of the accumulated capital expenditure to the end of that period. Thus, if adjusted profit is less than 15 per cent of accumulated capital expenditure during the safeguard period, then no PRT is payable. The 80 per cent tapering provision applies until the field is better off under the basic PRT rate.

Rate of PRT

Table A3.1 presents changes to the basic rate of PRT since its inception in 1975.

Table A3.1: The Rate of Petroleum Revenue Tax

Fiscal Year of Change	Rate (%)
1975	45
1979	60
1980	70
1983	75
1993	50 or 0[1]

Note: 1. In the 1993 Finance Act, the rate of PRT was reduced to 50 per cent for existing fields, but was abolished for new fields (i.e., those that had not been granted Annex B approval by Budget Day 1993).

Uplift and Payback

To compensate for the fact that no deduction is permitted in respect of interest payments, certain categories of capital expenditure qualify for an additional allowance (termed 'uplift'). Uplift does not apply once the field has reached 'payback', which is defined as being the point at which cumulative incomings (i.e., revenues) exceed cumulative outgoings. For these purposes, outgoings include *uplifted* capital expenditure, where applicable). Once payback has been achieved, capital expenditure in subsequent periods does not qualify for uplift, but can still be deducted from revenues in the normal way.

For the purposes of the model, it is assumed that *all* capital costs are subject to uplift. The uplift is currently equal to 35 per cent of the relevant expenditure (although expenditure before 1979 is uplifted by 75 per cent).

Oil Allowance

The oil allowance is a gross production relief which reduces a field's liability to PRT.

The oil allowance applies in any period in which a profit remains after deducting allowable profits from the assessable profits of a particular field. It is not calculated where there would not otherwise be a chargeable profit, and it cannot be used to create or enhance a loss.

For fields with Annex B approval after 1 April 1982, the maximum oil allowance is 500,000 tonnes per six-month period — in the model, an *annual* allowance of 1 million tonnes is used — up to a cumulative maximum of 10 million tonnes. Oil allowance that is not used in any period may be carried forward indefinitely.

In the model, for those fields that produce gas predominantly, the oil allowance is assumed to apply in the same way as above, by converting gas production into 'oil equivalent' terms.

Treatment of Abandonment Costs

There is no limit to the number of periods that losses arising from abandonment costs can be carried back and offset against assessable profits of earlier periods.

Corporation Tax (CT)

Basis of Calculation

Profits from oil and gas exploitation are liable to CT like any other form of company taxation. Since the 1991/92 fiscal year, the rate of corporation tax has remained unchanged at 33 per cent. Profit for CT purposes is defined in the model as gross revenues minus royalty payments, operating costs, PRT and capital 'writing down' allowances.

Capital Allowances

Capital allowances come in a variety of different forms. For the sake of simplicity in the model, the capital allowance represents expenditure on machinery and plant which, it is assumed, accounts for 80 per cent of a field's total capital costs (excluding abandonment costs). This expenditure qualifies for an annual writing down allowance of 25 per cent, based on a pool consisting of the undepreciated pool brought forward plus expenditure incurred in the relevant year.

Losses can be carried forward indefinitely and offset against future profits.

Treatment of Abandonment Costs

In March 1990, a new abandonment allowance was introduced, giving fields 100 per cent relief against corporation tax for abandonment costs. In addition, losses arising from abandonment can be carried back and offset against profits for up to three years for CT purposes.

Annex 3.2: Results of Different Fiscal Scenarios

Table A3.2: Total Tax Bills of *The New Fields* under Different Fiscal Scenarios. £ million, money-of-the-day

	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Oil Fields						
Alba	**511**	701	558	547	721	746
Alwyn North	**1,052**	1,214	1,070	1,093	1,233	1,272
Angus	**19**	26	19	19	26	26
Arbroath	**205**	308	269	205	333	346
Balmoral	**99**	177	99	99	177	177
Birch	**58**	88	58	58	88	88
Blenheim	**38**	54	38	38	54	54
Brae East	**1,942**	2,143	2,034	2,301	2,253	2,555
Chanter	**19**	28	19	19	28	28
Clyde	**148**	254	148	148	254	254
Columba D	**64**	64	64	81	64	81
Crawford	**-**	4	-	-	4	4
Cyrus	**19**	42	19	19	42	42
Don	**-**	16	-	-	16	16
Donan	**39**	39	39	39	39	39
Dunbar	**267**	441	271	278	447	441
Eider	**164**	226	195	167	240	243
Emerald	**-**	15	-	-	15	15
Fife	**57**	83	57	57	83	100
Gannet	**435**	635	441	445	636	637
Glamis	**29**	41	29	29	41	41
Gryphon	**114**	180	120	114	180	180
Harding	**379**	534	379	547	534	758
Hudson	**125**	179	162	129	201	213
Ivanhoe/Rob Roy	**379**	468	490	391	573	609
Kittiwake	**79**	127	89	80	127	127
Leven	**6**	10	6	6	10	10
Linnhe	**-**	1	-	-	1	1
Lvell	**15**	43	15	15	43	43
Medwin	**4**	7	4	4	7	7
Moira	**4**	7	4	4	7	7
Nelson	**1,344**	1,525	1,449	1,571	1,601	1,798
Ness	**70**	94	76	71	94	94
Osprey	**145**	211	177	145	219	223
Pelican	**147**	207	147	147	207	214
Petronella	**87**	115	88	87	115	115
Saltire	**210**	312	227	212	316	318
Scott	**1,299**	1,529	1,420	1,475	1,536	1,621
Staffa	**6**	10	6	6	10	10
Strathspey	**147**	239	165	149	247	251
T-Block	**155**	294	155	155	294	294
Tern	**1,049**	1,182	1,143	1,229	1,283	1,464
Gas Fields						
Amethvst	**200**	270	200	213	270	274
Beinn	**111**	145	111	126	145	152
Bruce	**2,271**	2,579	2,366	2,684	2,677	3,037
Ellon	**90**	129	98	90	130	130
Everest	**1,283**	1,426	1,361	1,467	1,493	1,661
Lomond	**79**	143	79	79	143	143
Miller	**774**	1,028	781	866	1,028	1,101

Note:
For details of the scenarios, see footnotes to Table A3.3.

Table A3.3: Internal Rates of Return of *The New Fields* under Different Fiscal Scenarios. Per cent

	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Oil Fields						
Alba	**16.6%**	14.3%	16.3%	16.3%	14.1%	13.8%
Alwyn North	**11.8%**	10.6%	11.7%	11.6%	10.5%	10.4%
Angus	**135.9%**	105.8%	135.9%	135.9%	105.8%	105.8%
Arbroath	**34.7%**	29.3%	32.3%	34.7%	28.3%	27.8%
Balmoral	**7.7%**	5.0%	7.7%	7.7%	5.0%	5.0%
Birch	**21.0%**	17.8%	21.0%	21.0%	17.8%	17.8%
Blenheim	**236.8%**	196.7%	236.8%	236.8%	196.7%	196.7%
Brae East	**15.8%**	14.4%	15.5%	14.8%	14.0%	12.9%
Chanter	**24.9%**	20.4%	24.9%	24.9%	20.4%	20.4%
Clyde	**9.4%**	6.6%	9.4%	9.4%	6.6%	6.6%
Columba D	**75.6%**	75.6%	75.6%	54.5%	75.6%	54.5%
Crawford	**negative**	negative	negative	negative	negative	negative
Cyrus	**0.9%**	-0.7%	0.9%	0.9%	-0.7%	-0.7%
Don	**negative**	negative	negative	negative	negative	negative
Donan	**63.0%**	63.0%	63.0%	63.0%	63.0%	63.0%
Dunbar	**15.9%**	12.4%	15.9%	15.8%	12.3%	12.4%
Eider	**18.9%**	15.8%	17.6%	18.8%	15.1%	15.0%
Emerald	**negative**	negative	negative	negative	negative	negative
Fife	**206.1%**	172.5%	206.1%	206.1%	172.5%	148.4%
Gannet	**13.6%**	11.3%	13.6%	13.6%	11.3%	11.3%
Glamis	**102.7%**	87.4%	102.7%	102.7%	87.4%	87.4%
Gryphon	**22.0%**	18.2%	21.8%	22.0%	18.2%	18.2%
Harding	**27.9%**	24.6%	27.9%	26.6%	24.6%	21.7%
Hudson	**203.2%**	118.8%	188.5%	200.7%	111.1%	107.0%
Ivanhoe/Rob Roy	**29.9%**	26.9%	27.0%	29.6%	23.9%	22.9%
Kittiwake	**13.9%**	10.2%	13.3%	13.9%	10.2%	10.2%
Leven	**134.6%**	94.4%	134.6%	134.6%	94.4%	94.4%
Linnhe	**negative**	negative	negative	negative	negative	negative
Lyell	**8.3%**	4.0%	8.3%	8.3%	4.0%	4.0%
Medwin	**38.6%**	28.9%	38.6%	38.6%	28.9%	28.9%
Moira	**33.2%**	26.0%	33.2%	33.2%	26.0%	26.0%
Nelson	**23.7%**	21.2%	23.2%	22.1%	20.9%	19.4%
Ness	**910.0%**	537.1%	806.9%	910.0%	536.4%	536.4%
Osprey	**25.2%**	21.9%	24.0%	25.2%	21.6%	21.4%
Pelican	**27.2%**	23.4%	27.2%	27.2%	23.4%	23.0%
Petronella	**87.8%**	77.2%	87.6%	87.8%	77.2%	77.2%
Saltire	**14.7%**	12.1%	14.4%	14.7%	12.0%	12.0%
Scott	**17.5%**	15.4%	17.0%	16.5%	15.5%	15.1%
Staffa	**8.4%**	-0.5%	8.4%	8.4%	-0.5%	-0.5%
Strathspey	**16.0%**	12.3%	15.5%	16.0%	12.0%	11.9%
T-Block	**4.7%**	2.0%	4.7%	4.7%	2.0%	2.0%
Tern	**19.3%**	17.9%	18.7%	17.9%	17.1%	15.6%
Gas Fields						
Amethyst	**19.9%**	17.0%	19.9%	19.5%	17.0%	16.9%
Beinn	**148.0%**	121.7%	148.0%	140.7%	121.7%	117.6%
Bruce	**16.0%**	14.1%	15.8%	14.8%	13.9%	12.8%
Ellon	**47.6%**	41.6%	46.2%	47.6%	41.5%	41.4%
Everest	**12.6%**	11.6%	12.3%	11.7%	11.3%	10.5%
Lomond	**2.8%**	-1.5%	2.8%	2.8%	-1.5%	-1.5%
Miller	**16.5%**	13.4%	16.4%	15.7%	13.4%	12.6%

Scenario 1: Royalty is not abolished for fields with Annex B after 1 April 1982.
Scenario 2: Oil allowance is not doubled for fields with Annex B after 1 April 1982.
Scenario 3: PRT is not reduced from 75 per cent and is applied to fields with Annex B after April 1993.
Scenario 4: Oil allowance is not doubled and royalty is not abolished for fields with Annex B after 1 April 1982.
Scenario 5: As above, and PRT is not reduced from 75 per cent and is applied to fields with Annex B after April 1993.

Annex 4: Cost Methodology

This Annex details the methodology used to estimate what the costs of UK North Sea oilfields would be if the only means of exploitation was through the use of a conventional production platform.

Choosing a 'Representative' Capital Cost

The first task is to estimate the capital cost of installing a conventional platform on those fields exploited by alternative means, such as subsea manifolds, deviated wells and floating production systems. To help in this aim, use has been made of *Wood Mackenzie* cost data of those 39 fields that have been exploited by means of a platform. The cost data have been converted to real (1996) values and a multiple regression performed to ascertain which variables are important in explaining overall platform costs. The variables tested include the:

- size of recoverable reserves of oil and gas
- depth of the water in which the platform stands
- year of construction and year of first production (as a proxy for the technology effect)
- construction material (steel, concrete or other)
- location in the North Sea (northern North Sea or central North Sea).

The results from the regression (which are summarized in Table A4.1) indicate that the only statistically significant variable in explaining the capital cost of the platform (including the cost of the platform structure, its equipment and the cost of installation) is the size of recoverable reserves of the field.

Table A4.1: Results of Regression of Platform Costs (1996 values) against Water Depth, Total Reserves, Year of Construction, Construction Material and Location in the North Sea

	Coefficients	Standard Error	t-Stat
Intercept	-11.587	18,617	-0.62
Water Depth	-0.11	2.73	-0.04
Total Reserves	0.85	0.11	7.97
Year of Construction	6.18	9.40	0.66
Dummy Variable 1 (Construction Material[1])	-290.26	218.72	-1.33
Dummy Variable 2 (Location in the North Sea[2])	-309.74	183.80	-1.69

Notes:
1. Dummy Variable 1 (Construction Material): 0 = steel platform; 1 = other (e.g., concrete, jack-up, tension leg platform)
2. Dummy Variable 2 (Location in the North Sea): 0 = Northern North Sea; 1 = Central North Sea

Table A4.2 ranks fields which are exploited by means of platforms according to the size of their recoverable reserves (in million barrels of oil equivalent). The real (1996) capital costs of each field's platform(s) are indicated.

On the basis of these costs, an assumption is made about the representative cost of installing a conventional platform on a field that is actually exploited by alternative means. In many cases, the recoverable reserves of fields for which estimates are being derived are well below those of existing platform-exploited fields. Indeed, total recoverable reserves of 'platformless' fields range from as high as around 150 million barrels of oil equivalent in the case of Amethyst and Strathspey to as low as 1 million barrels for Blair and Linnhe.[1] Therefore, in choosing a representative cost of a platform, the actual capital costs of fields that fall at the *lower* end of the recoverable reserves spectrum in Table A4.2 are considered.

Looking at those fields with recoverable reserves of between 51 and 100 million barrels, the platform that immediately stands out because of its high cost is Cormorant South. At almost £1,200 million (in 1996 prices), the cost of its platform is much higher than for fields with far higher reserve levels. This reflects the unusual nature of the Cormorant South structure. In addition to carrying its own production equipment, it also contains facilities necessary to perform other roles in the Brent pipeline system and the western leg gas pipeline (WELGAS). The platform is also the communication and air traffic control centre for the East Shetlands basin. These additional functions have boosted the cost of the platform, which means that the capital costs associated with the Cormorant South platform cannot be considered to be indicative of the cost of developing other fields.

Of the four other fields with total estimated recoverable reserves of between 51 and 100 million barrels of oil equivalent, Kittiwake boasts the cheapest platform costs, at £161 million in 1996 values. This was kept low because it made use of equipment previously used on the Auk platform. Consequently, the figure of £161 million is arguably a little too low to be considered as a 'representative cost' of installing a conventional platform.

Given the deep water and small reserve base of the Eider field, its developers made every effort to reduce the cost of its platform, which totalled £266 million in 1996 price terms. However, the Eider platform is somewhat unconventional in that it is an unmanned, minimal facilities structure, relying on the processing facilities of the nearby Cormorant North platform.

Whilst having modest reserves of condensate and NGLs, Lomond is primarily a gas field, which slightly weakens the case for using the £200 million cost figure of its platform as our 'representative cost' for installing a platform on an *oil* field given different equipment requirements.

[1] When the decision was taken to develop Linnhe, however, the estimate of recoverable reserves was somewhat higher (between 10 and 16 million barrels), but later downgraded significantly due to reservoir problems.

The Montrose platform, which is small by North Sea standards, cost almost £300 million in 1996 prices. However, the recoverable reserves of the field, at 95 million barrels of oil, fall at the upper end of the 51 to 100 million barrel range. Since regression analyses indicate the importance of reserve size in determining overall platform costs, this suggests that the figure of £300 million may overestimate the cost of installing a platform on a field with a much smaller reserve base.

Table A4.2: Cost of Platform Structures, Equipment and Installation, £ million (1996 values)

Reserves (mboe)	Platform	Cost £m	See Footnote
51 - 100	Cormorant (South)	1,199	
	Kittiwake	161	1
	Eider	266	2
	Lomond	200	3
	Montrose	299	4
101 - 150	Heather	583	
	Tiffany	690	
	Tartan	694	
	Auk	184	5
	NW Hutton	587	
	Gannet A	597	
	Saltire	379	6
	Clyde	609	
151 - 200	Everest	247	3
	Beatrice	625	
201 - 250	Hutton	1,428	
	Harding	235	7
	Maureen	978	
251 - 300	Tern	450	
301 - 350	Brae Area (B)	1,291	
	Alba	444	
351 - 400	Dunlin	636	
	Miller	970	
	Alwyn North	1,347	
401 - 500	Brae Area (A)	1,167	
	Thistle	1,606	
	Nelson	936	
	Cormorant (North)	715	
501 - 600	Brae East	689	
	Claymore	695	
	Scott	1,210	
601 - 700	Fulmar	774	
701 - 800	Bruce	968	
Over 801	Magnus	1,496	
	Piper	935	
	Ninian	3,358	
	Beryl	1,585	
	Forties	2,881	
	Brent	3,304	

1. The cost of the Kittiwake platform was kept low because it used equipment that was previously used on the Auk platform.
2. Eider has an unmanned, minimal facilities platform. Given the deep water and small reserve base of the field, every effort was used to reduce costs.
3. Fields producing gas predominantly.
4. Small by North Sea standards; manned.
5. Auk platform is a relatively small structure; has no storage facilities, relying on the Fulmer FSU instead.
6. Conventional platform installed in 1992.
7. Harding uses a jack-up concept rather than a conventional platform.

Source: Derived from Wood Mackenzie cost data.

Whilst there does not appear to be a single 'ideal' platform to be used as a guide to estimate the theoretical capital cost of installing a conventional platform on a field that is actually exploited by alternative means, the range of costs of the Eider, Montrose, Lomond and Auk fields is relatively narrow. It therefore seems reasonable to take a simple average of this range to derive a representative capital cost estimate. On this basis, the following assumption is made:

For fields with total reserves of 100 million barrels of oil equivalent or less, it is estimated that the capital cost of a conventional platform would be £230 million in 1996 prices.

A small number of the fields which are not actually exploited by means of a conventional platform have reserve estimates greater than 100 million barrels of oil equivalent. To estimate the theoretical costs of installing a platform on these fields, the actual platform costs of those fields that fall within the 101 to 150 million barrel grouping in Table A4.2 are used as a guide. The range of costs within this grouping of fields is much more diverse — from as low as £184 million (in 1996 prices) in the case of Auk (where the low cost is a reflection of the lack of storage facilities on the platform), to as high as £694 million for the Tartan platform (which is one of the North Sea's oldest structures).

Because of this diversity, it does not seem appropriate to take a simple average; rather, the cost of the Saltire platform — which, at almost £380 million, falls at the lower end of the cost range — is taken to be representative. The Saltire structure is a conventional platform that was installed in 1992. Thus, the second cost assumption is:

For fields with total reserves of between 100 and 150 million barrels of oil equivalent, it is estimated that the capital cost of a conventional platform would be £380 million in 1996 prices.

Having made these assumptions about platform costs, the cash flows of those fields actually exploited by 'non-platform methods' are adjusted as if a platform is installed. All other capital costs (including development drilling and flowlines) remained unchanged. Since the cash flows are presented in money-of-the-day terms, an adjustment is made to convert the real (1996) platform costs into a money-of-the-day basis. In the absence of an indicator to reflect inflation within the North Sea oil sector, the UK Index of Manufacturing Output Prices is used for this purpose.

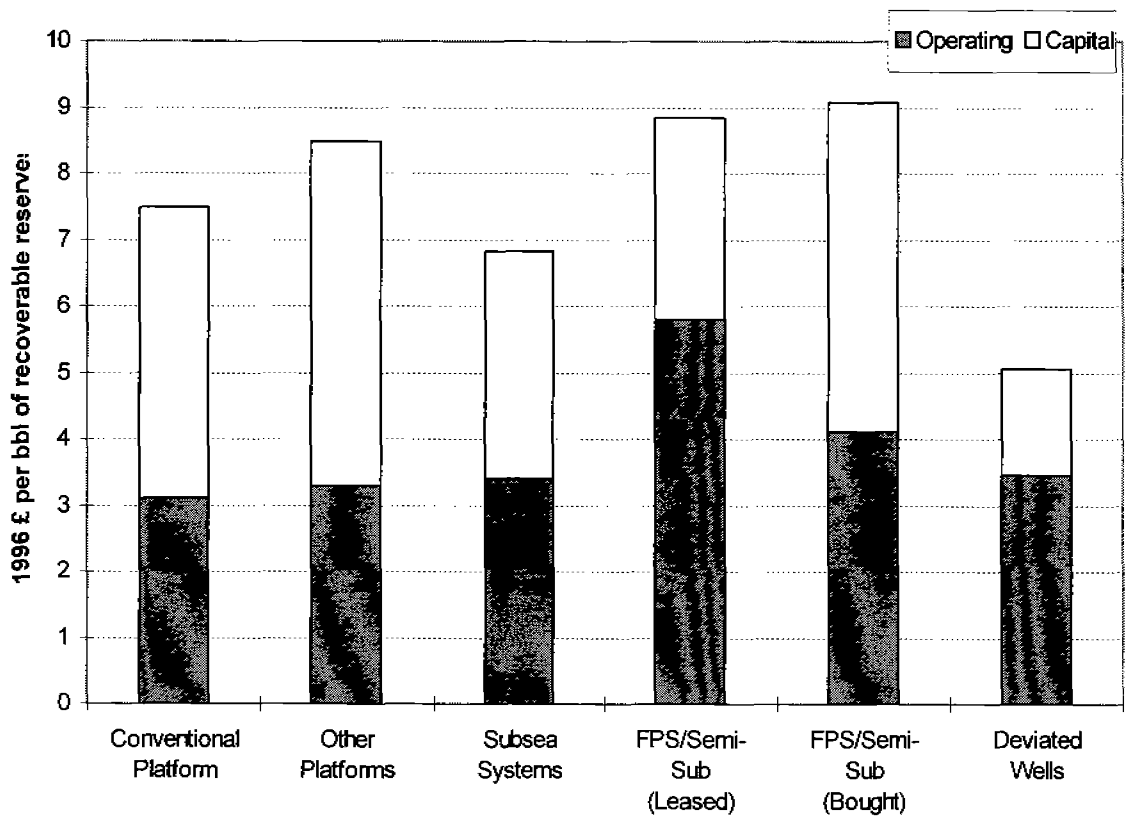
It is also necessary to adjust the cash flows to take into account that the costs of abandonment of a conventional platform tend to be higher than those associated with the disposal of other means of field exploitation (subsea manifolds, deviated wells and floating production systems, for example). On the basis of *Wood Mackenzie's* estimates of abandonment costs for existing conventional platforms for fields with recoverable reservesof less than 150 million barrels of oil equivalent, a figure of £50 million in 1996 prices is used as the 'representative' abandonment cost.

Choosing Appropriate Operating Costs

Differences in Costs between Different Types of Structure

By imposing the assumption that all fields are exploited by means of a conventional platform, it is necessary not only to re-estimate the capital costs of fields that are actually exploited by alternative means, but also to re-estimate *operating costs.* This point is illustrated by Diagram A4.1, which has been derived on the basis of real (1996) costs,[2] and highlights differences in the costs between the various methods of oil exploitation that are currently used in the UK North Sea. The costs in Diagram A4.1, which distinguish between capital and operating costs, are expressed in terms of per barrel of recoverable reserves and are calculated over the lifetime of the fields concerned. The costs are averaged, weighted according to the recoverable reserves of the field.

Diagram A4.1: Real Weighted Average per Barrel Costs by Type of Structure



On average, fields that are exploited by deviated, extended or horizontal wells have the lowest per barrel costs, at around £5/bbl in 1996 values. Subsea systems have costs of just below £7/bbl on average. At the other end of the spectrum, floating production and semi-

[2] As published by Wood Mackenzie in its North Sea Service (November 1996)

submersible systems have average costs of approximately £9/bbl. The figure of £7.5/bbl for fields with conventional platforms disguises a great deal of variation between the costs associated with fields having different reserve bases, as a result of economies of size. These differences are stripped away in Diagram A4.2, which reveals that average per barrel costs of conventional platforms on fields with recoverable reserves of over 800 million barrels of oil equivalent are below £7/bbl in 1996 money terms, compared with over £12/bbl for fields with reserves below 200 million barrels. This reinforces the point that conventional platforms are *not* the most cost effective means of exploiting small fields.

Diagram A4.2: Real Weighted Average per Barrel Costs of Conventional Platforms by Size of Reserves

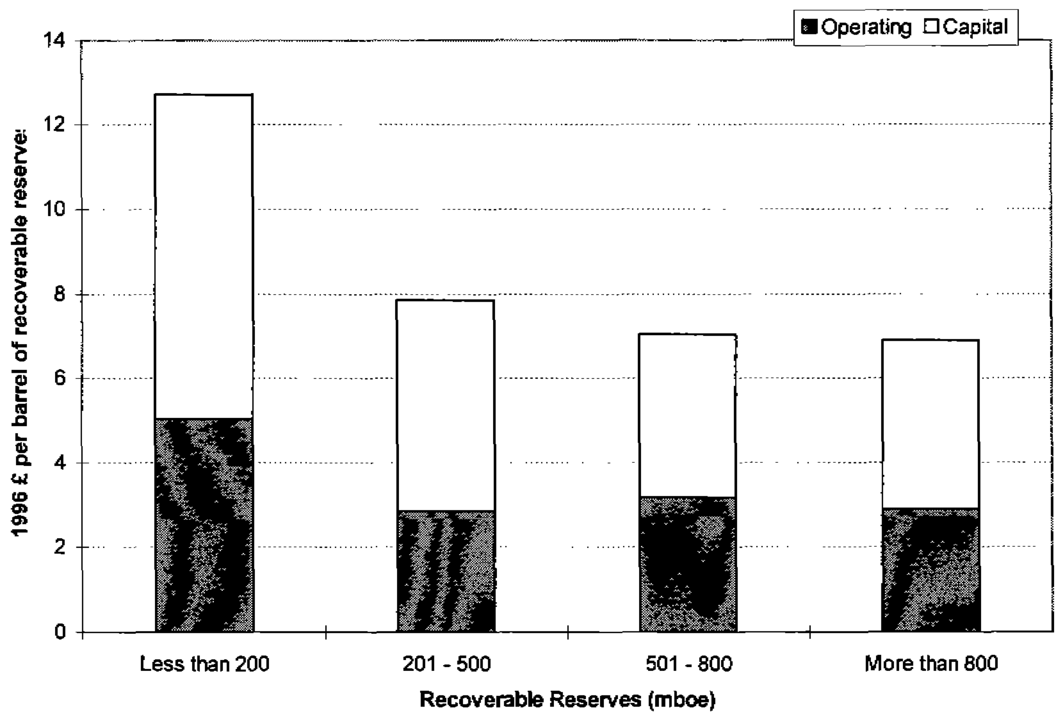
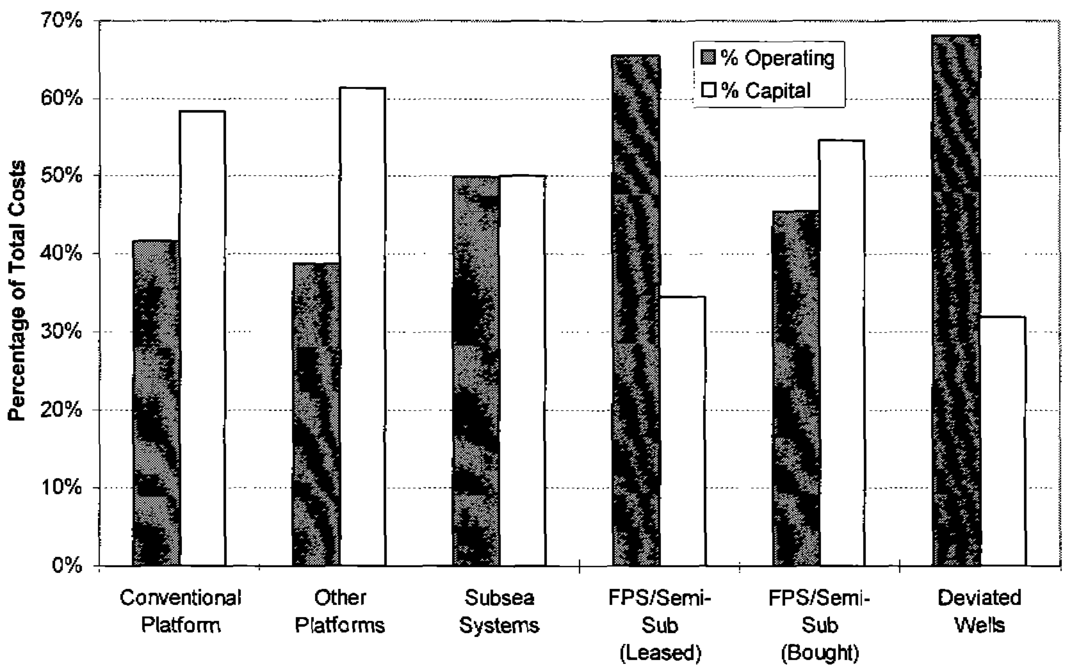


Diagram A4.3 presents the cost information in a slightly different way, by highlighting the balance of overall costs between capital and operating expenditures. Thus, it is seen that, in the case of those fields exploited by means of platform (either conventional or unconventional), the balance of costs is skewed in favour of capital costs, which account for 58 and 62 per cent of total costs, respectively. For subsea systems, there is an equal balance between the two elements of cost. For floating production and semi-submersible systems, the balance between capital and operating costs depends on whether the vessel is leased (because rental payments are classified as operating costs), or bought and owned by the field's operators (in which case the cost of the vessel is treated as a capital cost). In the former case, operating costs account for approximately two-thirds of overall costs on average, while in the latter, operating costs represent 43 per cent of total cost expenditure. Finally, those fields exploited by means of deviated, horizontal or extended-reach wells have the highest operating cost element of all, in percentage terms, accounting for almost 70 per cent of total costs. This mainly represents tariff payments to other fields for the use of their processing and export facilities.

Diagram A4.3: Percentage Breakdown of Costs between Capital and Operating Expenditure by Type of Structure

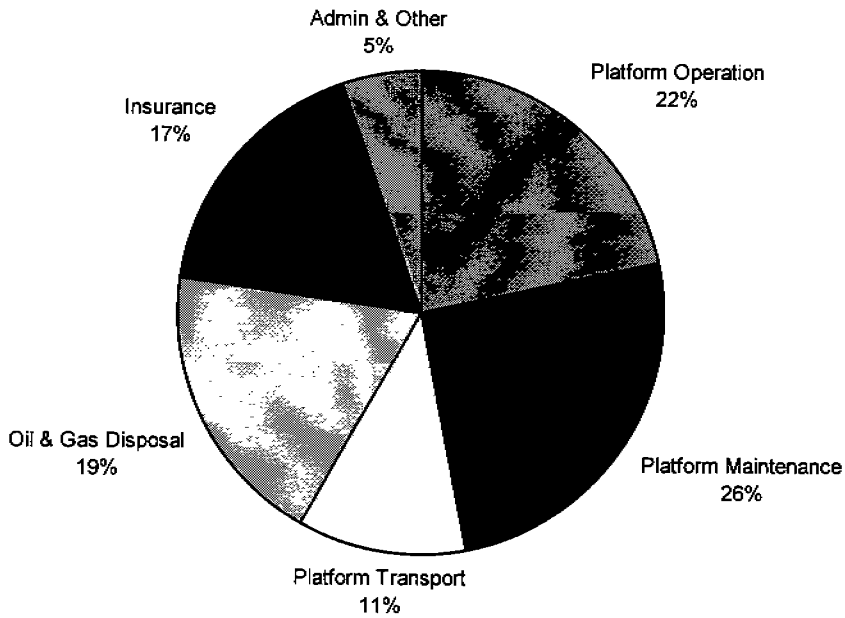


Adjusting Operating Costs

To assist in the aim of estimating what the operating costs of a field would be if it were to be exploited by means of a platform rather than other methods, it is useful to study the typical breakdown of operating costs of small conventional platforms. This is presented in Diagram A4.4. A large number of the cost elements that comprise operating costs — such as insurance, maintenance and administration — can be classified as fixed costs[3] (i.e., they are independent of the level of production). This suggests that unit operating costs will decline at higher rates of production as a result of economies of size.

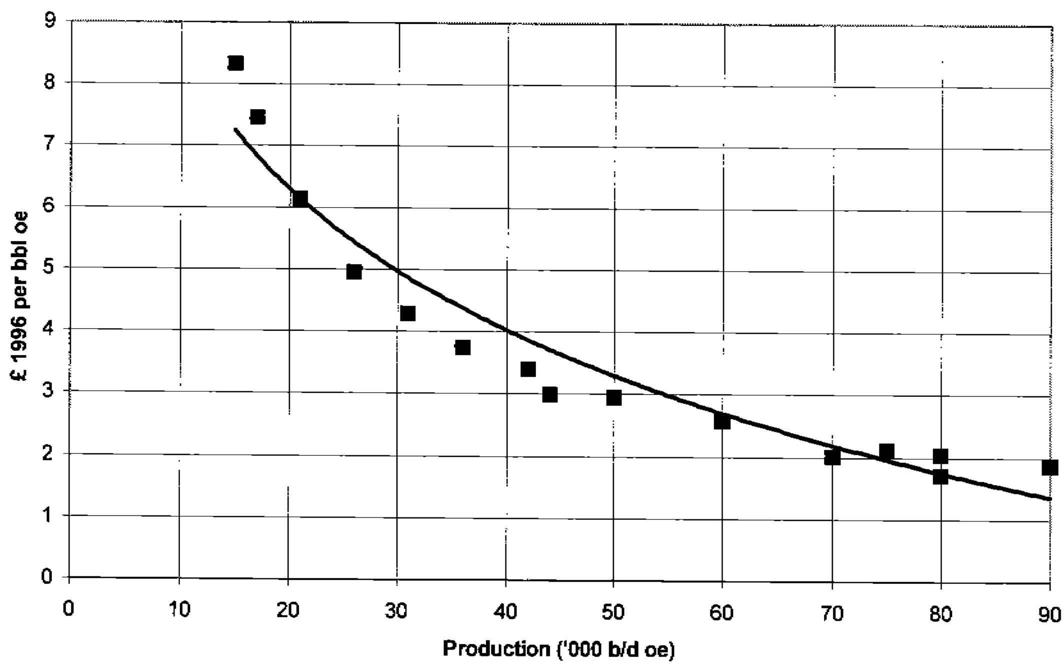
[3] For this reason, the definition of 'operating costs' as applied here does not mean the same thing as 'variable costs' as defined by an economist.

Diagram A4.4: Typical Breakdown of Platform Operating Costs

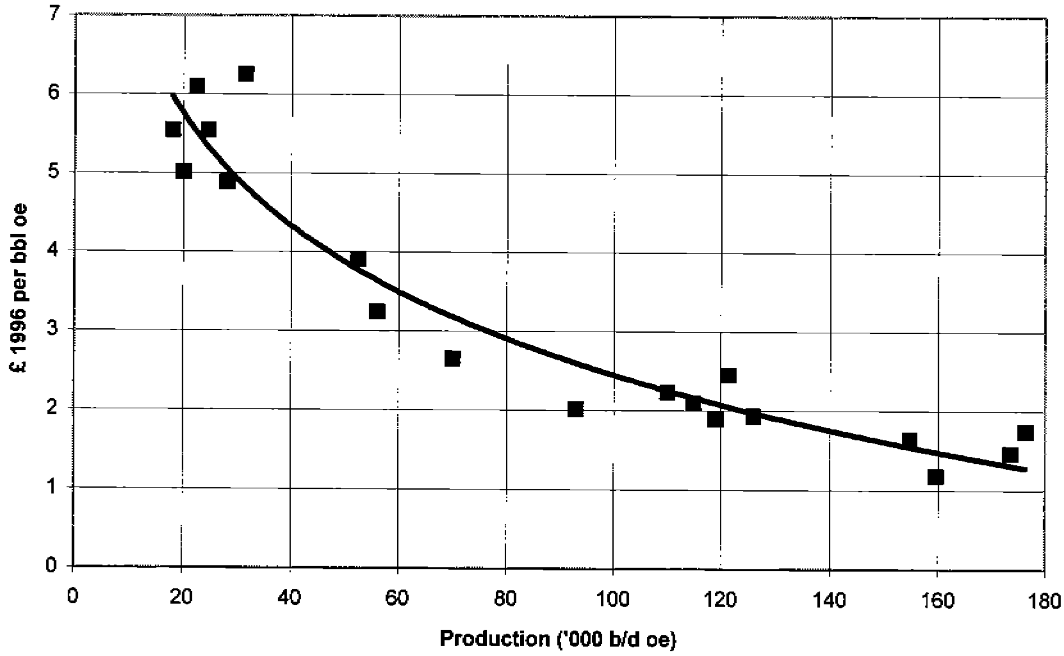


Plotting the relationship between unit operating costs (i.e., expressed per barrel of annual production of oil and gas, in oil equivalent terms) and annual production rates for those fields which are currently exploited by means of a conventional platform does indeed indicate the existence of economies of size. Diagrams A4.5 to A4.8 provide some particularly clear examples of this.

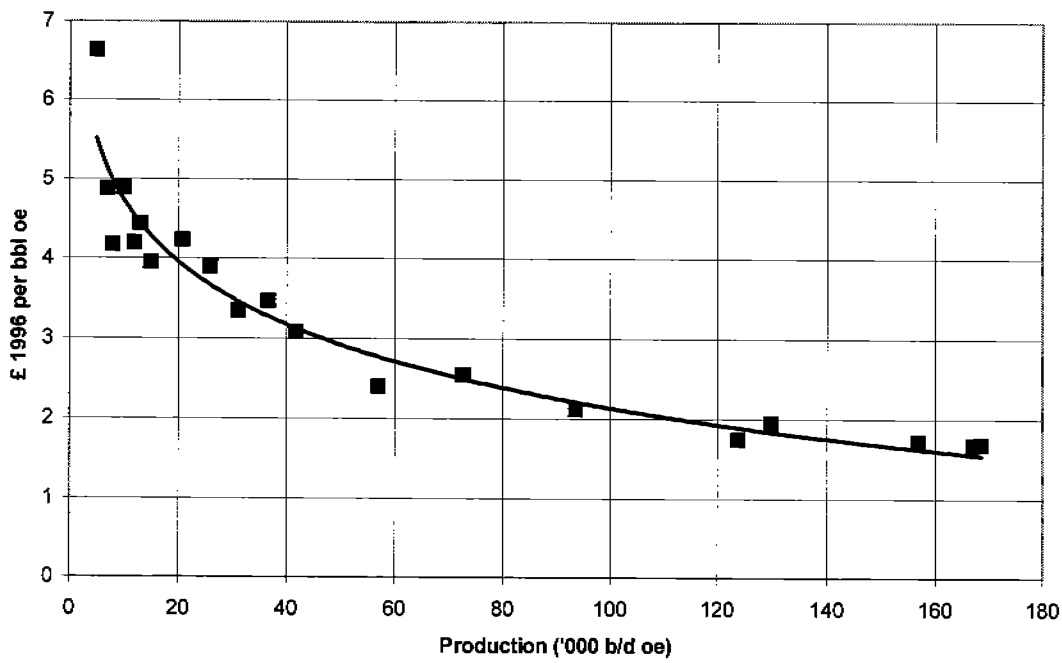
Diagrams A4.5: Alba - Real per Barrel Operating Costs



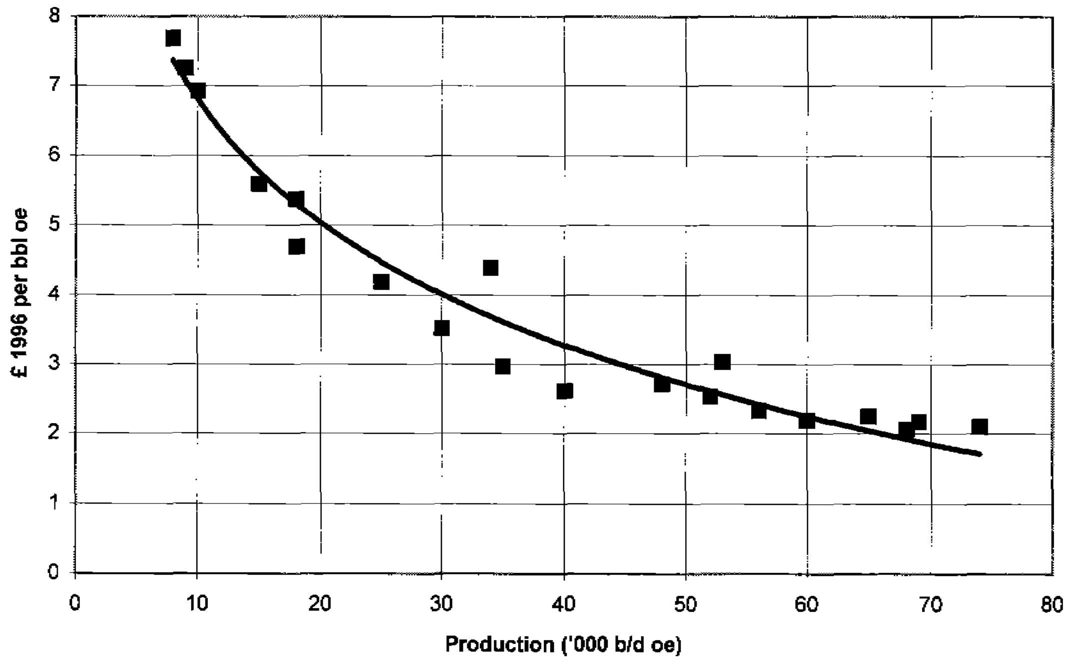
Diagrams A4.6: Fulmar - Real per Barrel Operating Costs



Diagrams A4.7: Nelson - Real per Barrel Operating Costs



Diagrams A4.8: Tern - Real per Barrel Operating Costs



In estimating what the operating costs of the fields would be if they were to be exploited by a conventional platform, it seems sensible to be guided by the operating costs of the same group of fields that were used to find a 'representative' capital cost — i.e., those fields with similar reserve bases. To be used in the cash flow analysis that is integral to the taxation model described in Chapter 3, it is necessary to know total operating costs on an *annual* basis. As discussed above, these costs will be dependent upon the level of production. Derived from Wood Mackenzie estimates and forecasts, the relationship between real (1996) annual operating costs and production levels for fields with platforms can be plotted. In each case, a linear trend line has been fitted to the data. On this basis, it is possible to make assumptions about the relationship between production levels and annual operating costs. Analysis of these trend lines reveals quite a wide disparity in the size of the fixed cost element (i.e., the constant term of the trend line equation) and in the variable element (i.e., the part of cost that is dependent on the level of production), even among fields with similar reserve bases. For this reason, the estimates of operating costs have been derived on the basis of data from *several* fields. However, because a significant part of operating costs will be related to the size of a platform — which, in turn, is related to the size of recoverable reserves — the analysis is confined to those fields with reserves of less than 150 million barrels of oil equivalent.

Diagrams A4.9 to A4.18 chart the relationship between production and annual real operating costs for fields which each have recoverable reserves of up to 150 million barrels of oil equivalent. In each case, a linear trend line has been fitted. In order to estimate the operating costs of those fields which are actually exploited by alternative means but which are assumed to be exploited by means of a conventional platform, a 'hybrid' of these equations is used, leading to the following assumptions.[4]

- For fields with total reserves of 100 million barrels of oil equivalent or less, annual real (1996) operating costs are calculated according to the equation:

$$y = 11.89 + 0.91x$$

where:

y = annual real (1996) operating costs

x = annual production ('000 b/d, oe)

- For fields with total reserves of between 100 and 150 million barrels of oil equivalent, annual real (1996) operating costs are calculated according to the equation:

$$y = 14.58 + 0.98x$$

where:

y = annual real (1996) operating costs

x = annual production ('000 b/d, oe)

[4] Given that operating costs can be fully offset against a field's tax liability, it could be argued that the precise nature of these assumptions is relatively unimportant, since the impact that operating costs have on the calculation of a field's internal rate of return (IRR) is somewhat muted.

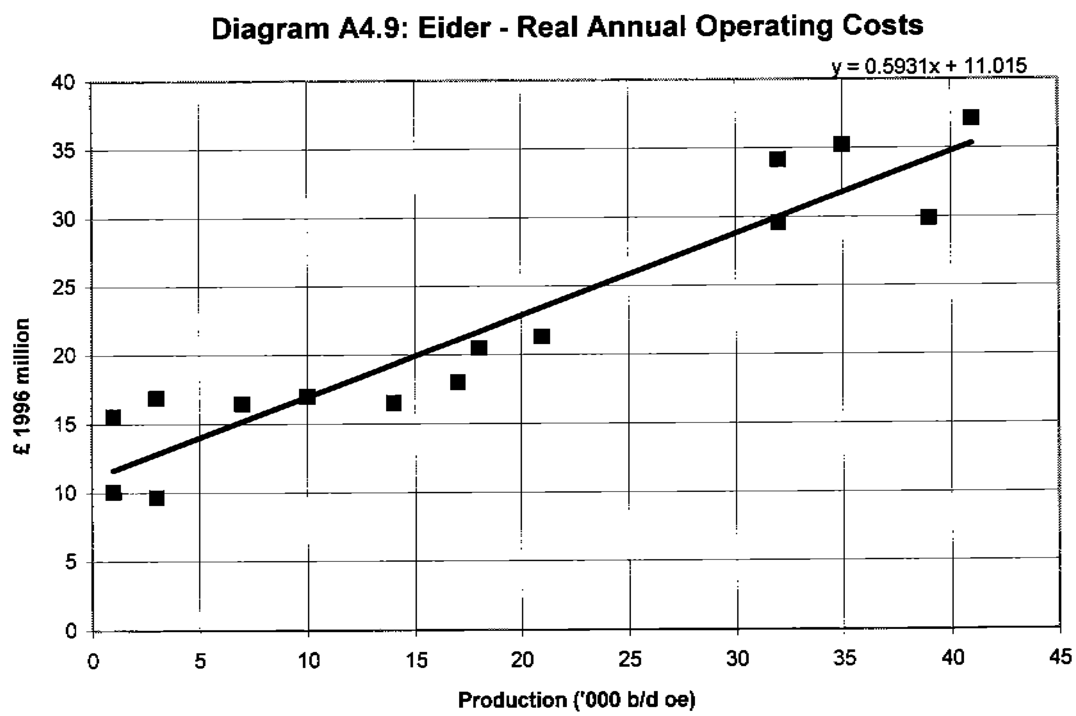


Diagram A4.9: Eider - Real Annual Operating Costs
y = 0.5931x + 11.015
£ 1996 million
Production ('000 b/d oe)

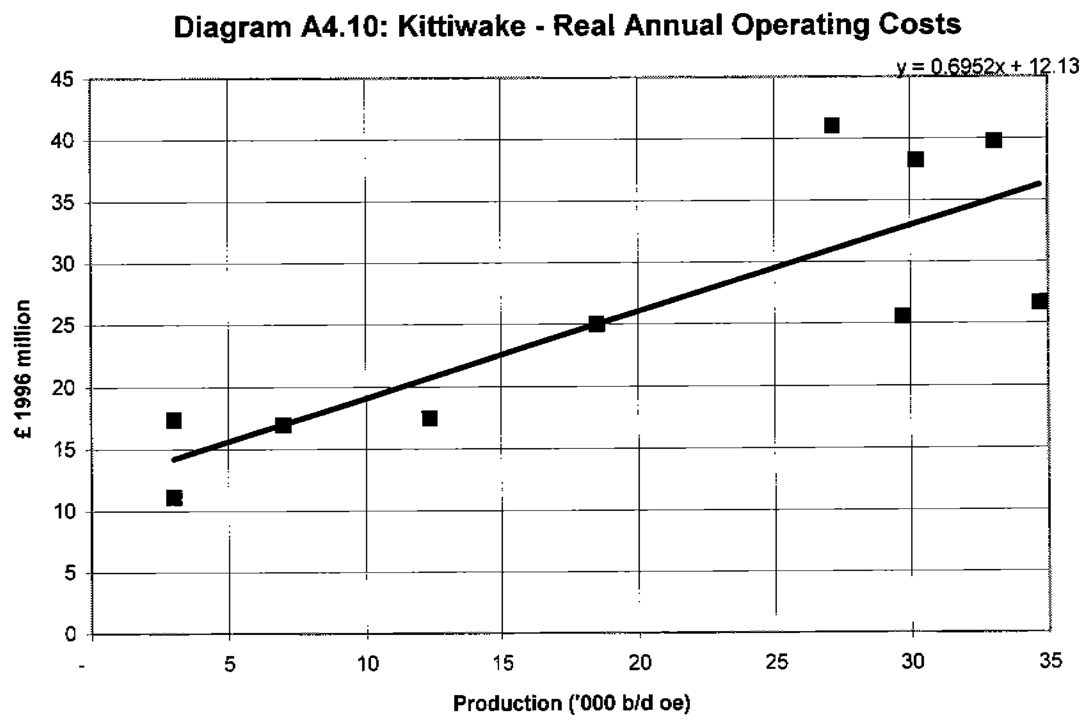


Diagram A4.10: Kittiwake - Real Annual Operating Costs
y = 0.6952x + 12.13
£ 1996 million
Production ('000 b/d oe)

Diagram A4.11: Lomond - Real Annual Operating Costs

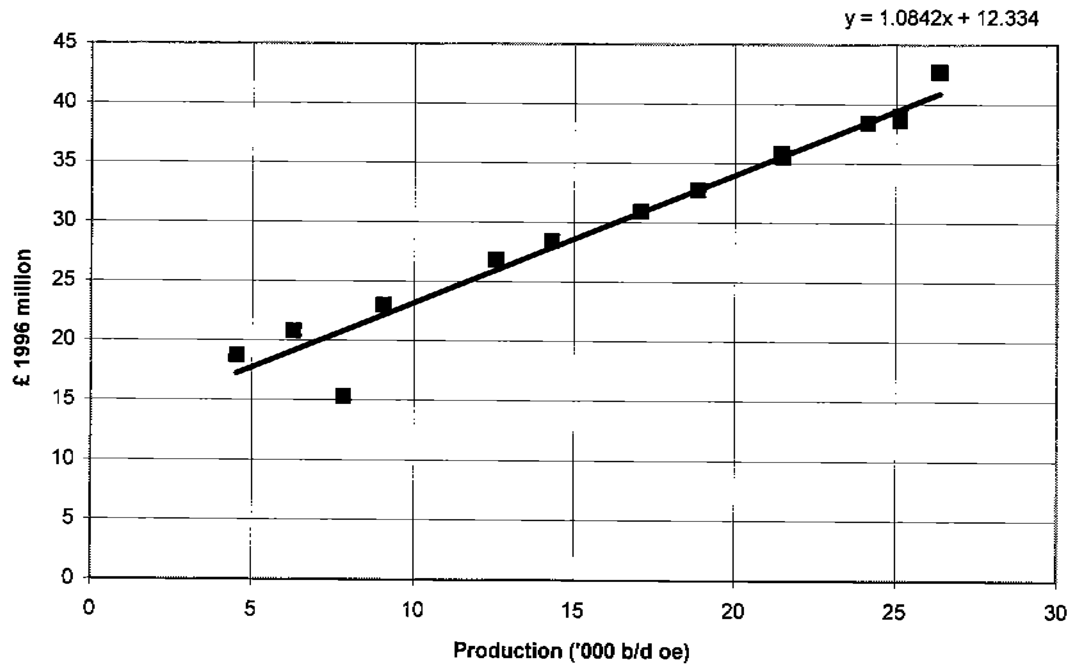


Diagram A4.12: Montrose - Real Annual Operating Costs

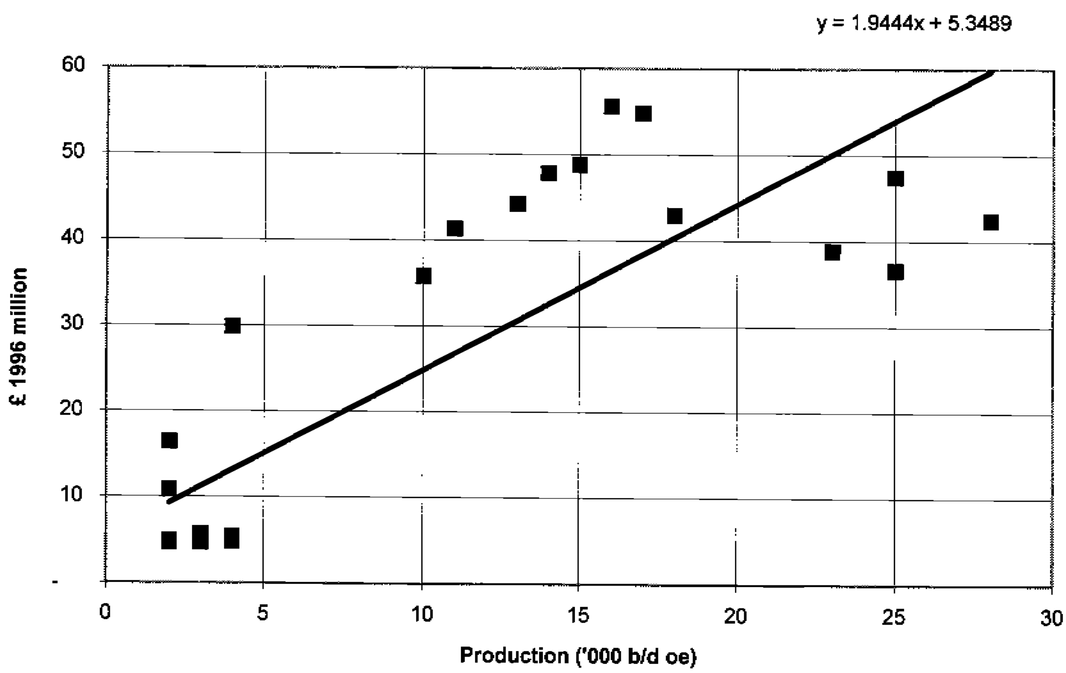


Diagram A4.13: Auk - Real Annual Operating Costs

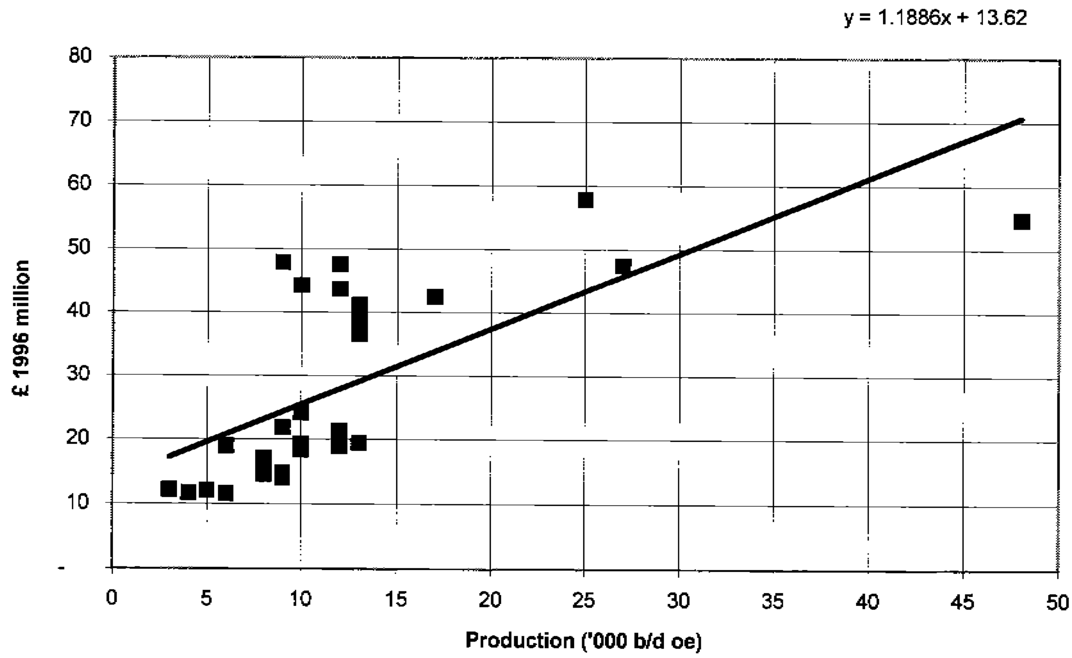


Diagram A4.14: Clyde - Real Annual Operating Costs

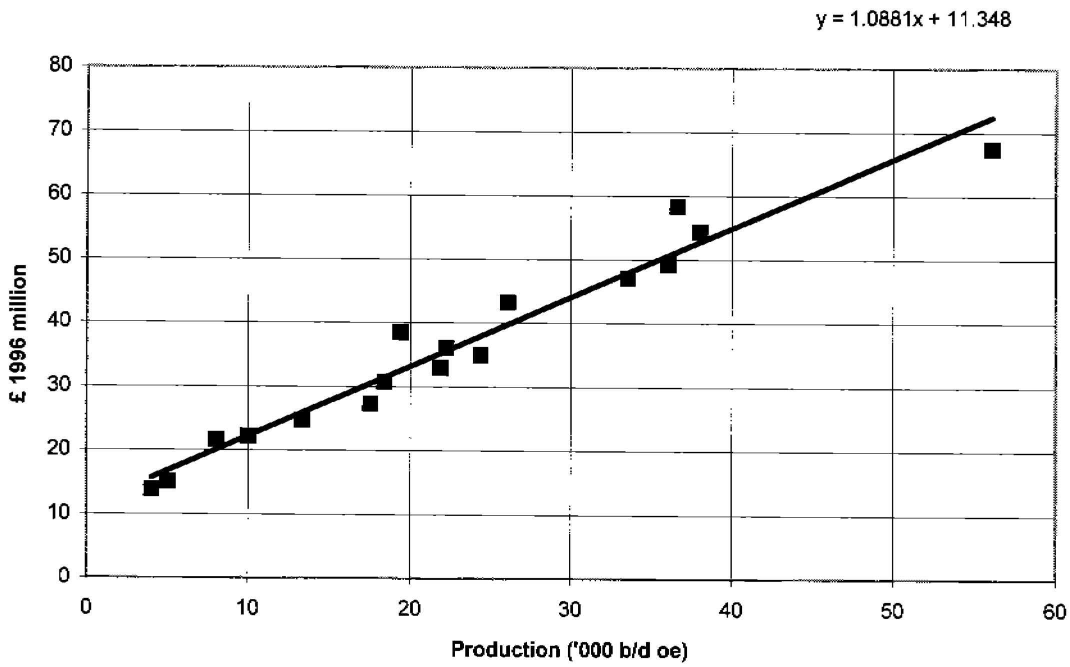


Diagram A4.15: Heather - Real Annual Operating Costs

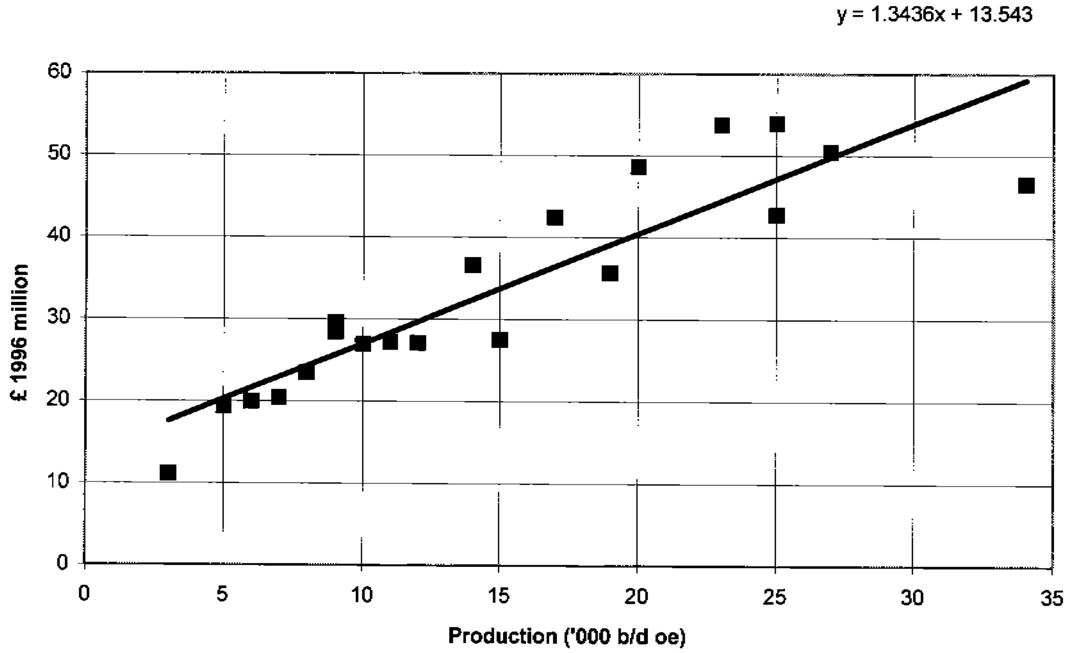


Diagram A4.16: NW Hutton - Real Annual Operating Costs

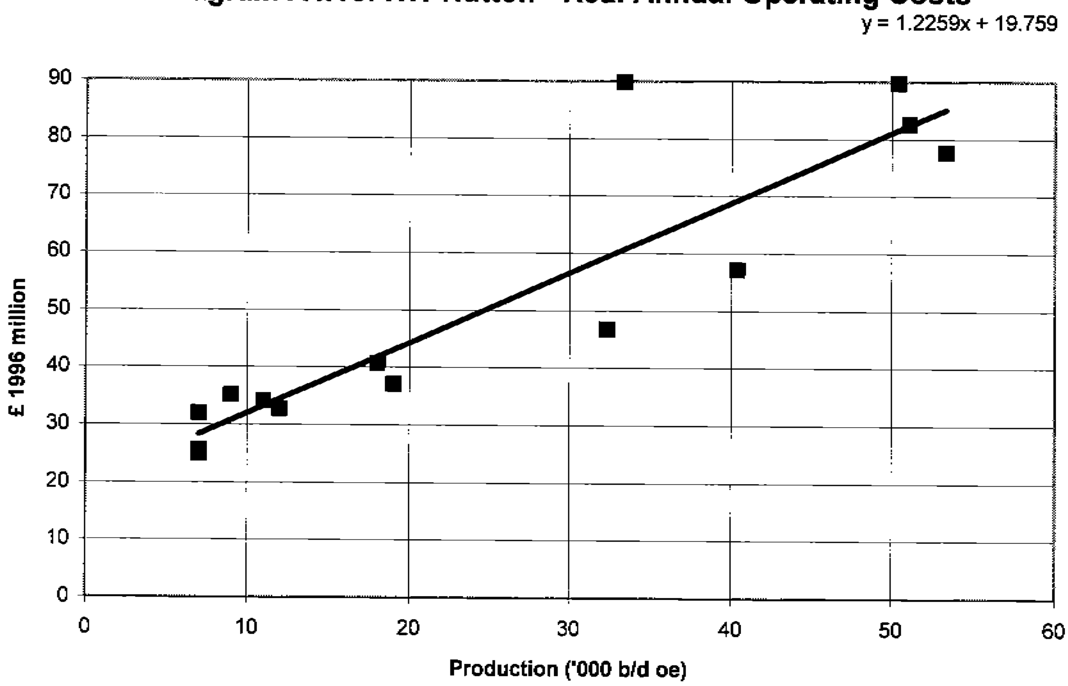


Diagram A4.17: Saltire - Real Annual Operating Costs

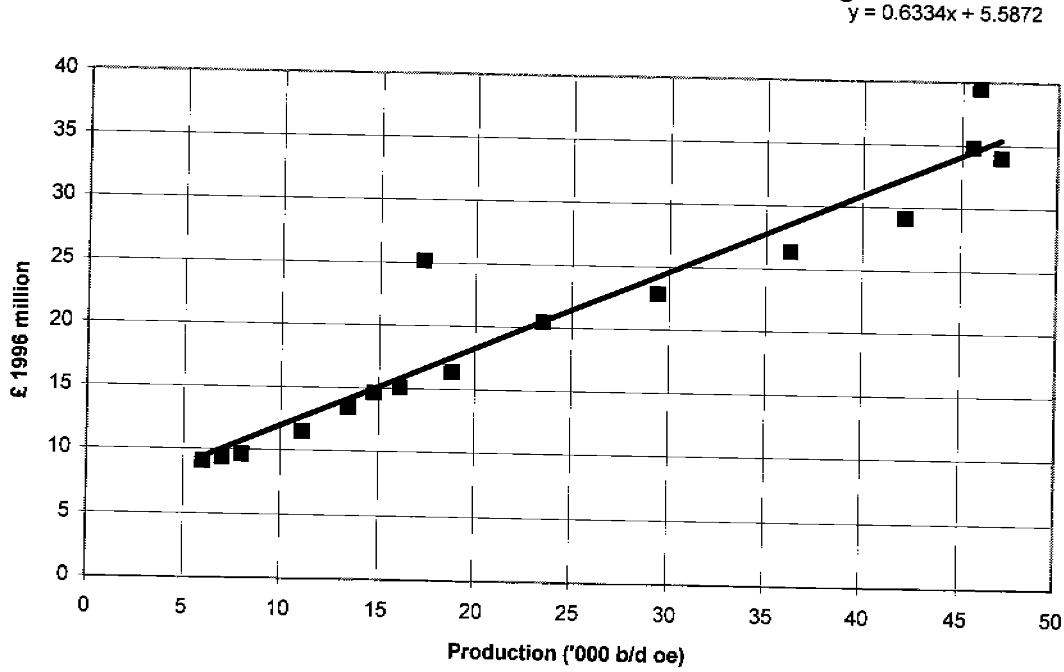
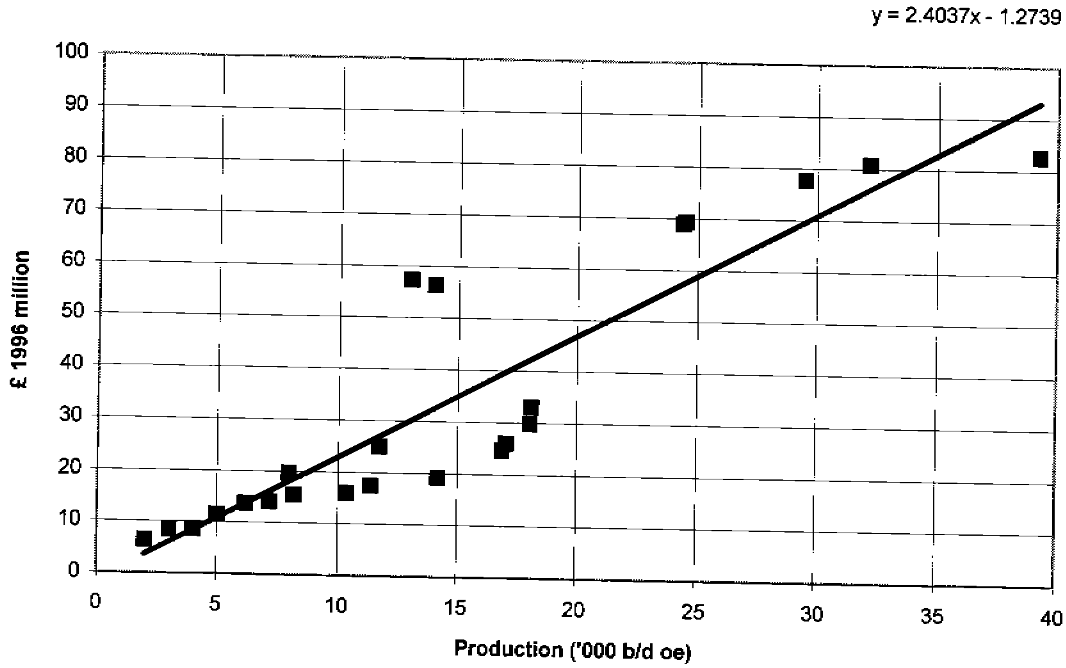


Diagram A4.18: Tartan - Real Annual Operating Costs

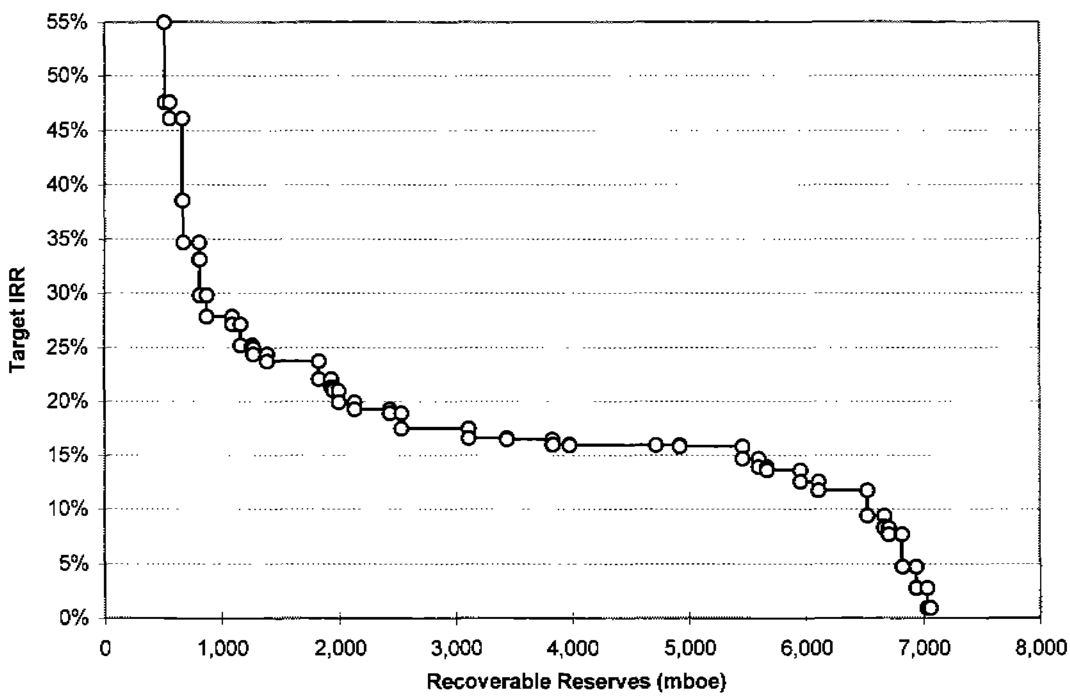


Annex 5.1: Sensitivity of Reserve Base to Different Target IRRs

Derived by ranking fields according to their IRR under the different fiscal and technology and recent discovery scenarios described above, Diagrams A5.1 to A5.4 reveal the reserves that would be forthcoming from the fields included in the analysis at different target levels. The higher the target level, the fewer fields that are able to meet the development criterion and hence the lower the volume of oil reserves that would be forthcoming. At the other extreme, if fields only have to achieve a low target IRR before the decision is taken to proceed with their development, then one would expect to see a higher reserve base coming into production.

Diagram A5.1 represents the base case, which illustrates the situation under *existing* fiscal and technology conditions. At extremely high target IRRs, say 35 per cent, the model suggests that only modest reserves (approximately 670 mboe) would be forthcoming from the fields included in the analysis. If, on the other hand, the target IRR is just 5 per cent, many more fields would meet the development criterion, with the curve in Diagram A5.1 indicating that close to 7 billion barrels of oil equivalent would be recoverable from the fields coming on stream.

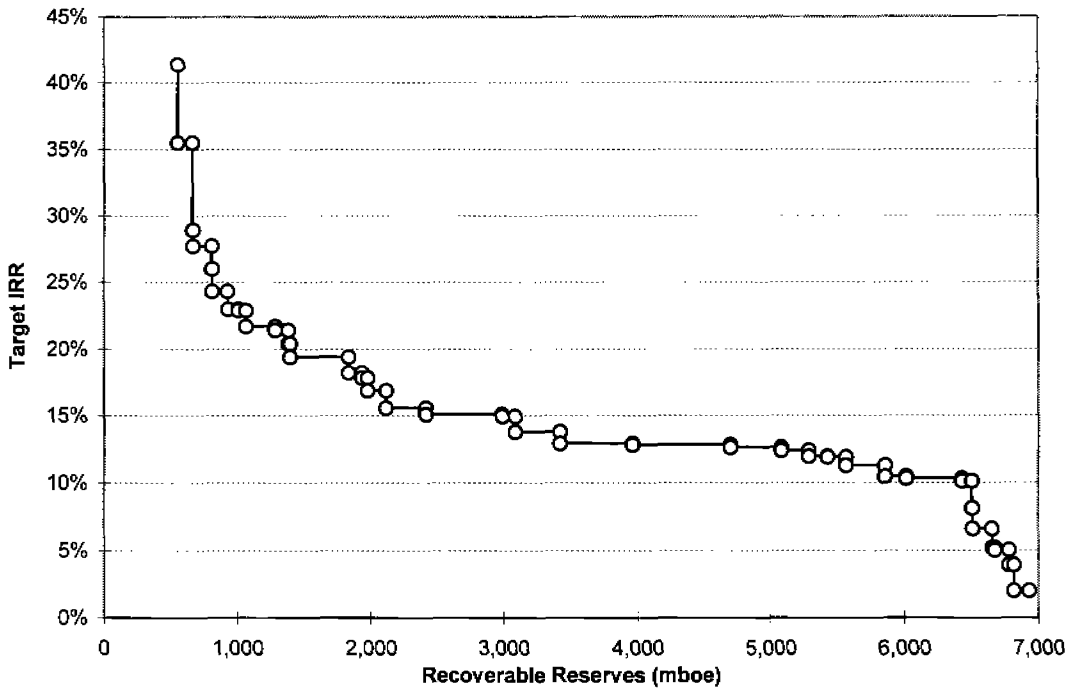
Diagram A5.1: Reserves Forthcoming at Different Target IRRs - Base Case



Diagrams A5.2 to A5.4 depict how the shape of the curve would change under the different fiscal and technology scenarios. Diagram A5.2 highlights the impact of the fiscal changes, illustrating the reserves that would be forthcoming at different target IRRs under existing technology but without the main fiscal changes of 1983 and 1993, whilst

Diagram A5.3 isolates the technology effect, where the existing fiscal arrangements are assumed, but where IRRs have been re-calculated on the basis that all the fields are exploited by means of a conventional production platform (i.e., they do not benefit from cost-saving production technology).

Diagram A5.2: Reserves Forthcoming at Different Target IRRs - Without the 1983 and 1993 Fiscal Changes



Whilst Diagrams A5.2 and A5.3 *separate* the impact of the fiscal and technology scenarios, Diagram A5.4 *combines* the impact of the two effects. In other words, Diagram A5.4 reveals the reserves that would be forthcoming at different IRR targets when IRRs are re-calculated on the assumption that the main fiscal changes of 1983 and 1993 did not occur *and* no technological progress has been made (so that the cost structure of fields would reflect the situation if they were all exploited by means of a conventional production platform). Under these circumstances, the IRRs of the fields would be lower than under the base case, with the result that the volume of reserves forthcoming for each target IRR level would also be lower.

Diagram A5.3: Forthcoming Additional Reserves at Different Target IRRs — Without New Technology

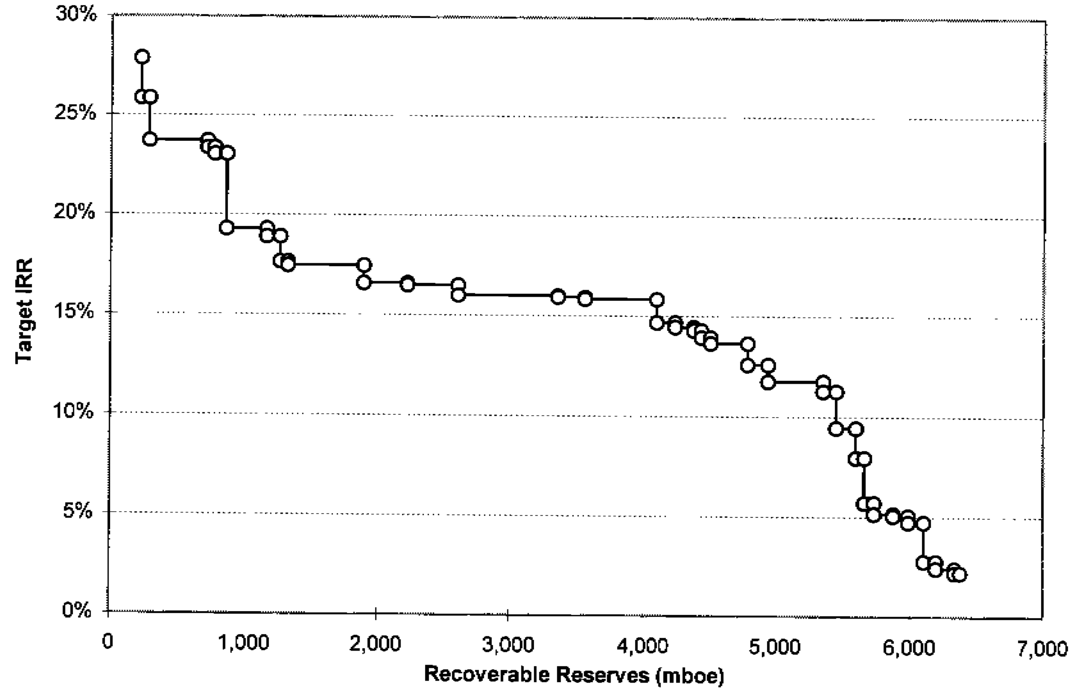
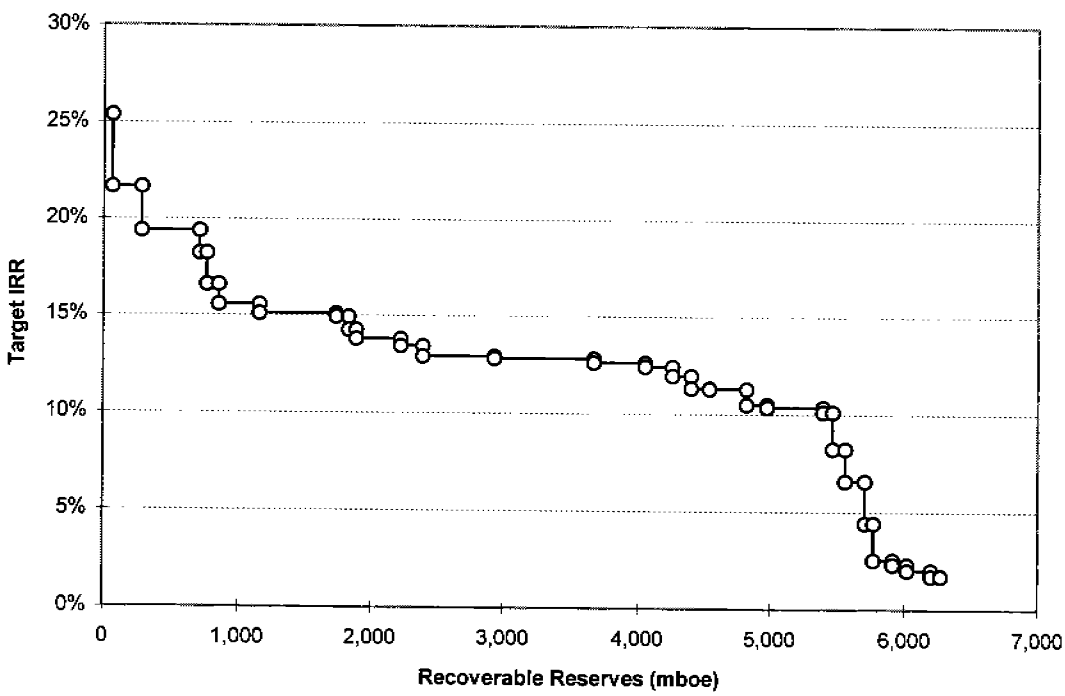


Diagram A5.4: Forthcoming Additional Reserves at Different Target IRRs — Without Both New Technology and Fiscal Changes



Annex 5.2: Calculation of Tax Sacrificed from Established Fields as a Result of PRT Falling from 75 to 50 Per Cent

For each of the established fields in the UK North Sea sector, Table A5.1 shows Wood Mackenzie's estimates of gross revenues to be earned after 1993 (the year of the PRT reduction). Using these figures, the difference in tax take of the fields after 1993 is calculated by comparing what the total PRT and corporation tax (CT) bill would be if PRT remained at 75 per cent with the current situation of a 50 per cent PRT. (Although, in practice, royalty will also have to be paid by the established fields, there is no need to include this element of taxation in the calculation in Table A5.1 because the amount of royalty is *independent* of PRT and CT. Since the total amount of royalty paid will not be altered by changing the rate of PRT, it is not necessary to include it when calculating the *difference* in a field's total tax bill as a result of reducing PRT to 50 per cent.) A simple calculation is assumed: the revenue figures are multiplied by the appropriate rate of PRT and then by CT at 33%.[1]

[1] This simplification is reasonable: by 1993, most of the oilfields would have used up their oil allowances (which would have complicated the PRT calculation). Moreover, any capital allowances after 1993 would be applicable under *both* PRT scenarios, and would simply cancel each other out in the calculation of the *difference* in total tax take.

Table A5.1: The Established Fields:[1] Change in Tax Take as a Result of the Change in PRT from 75 to 50 Per Cent. £ million, money-of-the-day

	Gross Revenue (GR) Earned After 1993	GR *times* 75% PRT *times* 33% CT	GR *times* 50% PRT *times* 33% CT	Difference (Tax Sacrificed)
Auk	361	89	60	30
Beatrice	196	49	32	16
Beryl	9,910	2,453	1,635	818
Brae Area	6,175	1,528	1,019	509
Brent	14,988	3,710	2,473	1,237
Claymore	2,049	507	338	169
Cormorant	3,188	789	526	263
Dunlin	887	220	146	73
Forties	10,656	2,637	1,758	879
Fulmar	1,113	275	184	92
Heather	99	25	16	8
Hutton	507	125	84	42
Magnus	3,574	885	590	295
Maureen	217	54	36	18
Montrose	143	35	24	12
Murchison UK	291	72	48	24
Ninian	2,887	715	476	238
NW Hutton	131	32	22	11
Piper	2,984	739	492	246
Statfjord UK	2,708	670	447	223
Tartan	361	89	60	30
Thistle	391	97	65	32
Viking	702	174	116	58
Total	**64,518**	**15,968**	**10,645**	**5,323**

Note:

1. The fields included in this analysis are those in *The 1985 Group* excluding those exploited by non-conventional means: Argyll, Buchan, Deveron, Duncan, Highlander, Innes and Scapa.

Source of Gross Revenue Data: Wood Mackenzie

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