THE POTENTIAL SOCIO-ECONOMIC IMPLICATIONS OF LICENSING THE SEA 4 AREA

A REPORT

for the
DEPARTMENT OF TRADE AND INDUSTRY
by
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1.0 INTRODUCTION

1.1 The UK Department of Trade and Industry (DTI) is conducting a Strategic Environmental Assessment (SEA) of licensing parts of the UK Continental Shelf (UKCS) for oil and gas exploration and production. This SEA 4 is the fourth in a series planned by the DTI, which will, in stages, cover the whole of the UKCS.

1.2 The SEA 4 area is shown on the map on the following page. It includes the most northerly part of the UKCS, north of the Shetland Islands between the international boundaries with Norway and the Faroe Islands, and the area to the west of Shetland and the Orkney Islands.

1.3 It can be subdivided into three areas:

(1) the area of existing and previously licensed acreage;
(2) the northern area which has never been licensed;
(3) the coastal waters close to Shetland and Orkney.

1.4 Mackay Consultants were asked by Hartley Anderson Ltd and Geotek Ltd, on behalf of the DTI, to assess the socio-economic implications of licensing the SEA 4 area. This report sets out the results of our work, in relation to

- oil and gas production, and reserves
- capital, operating and decommissioning expenditure
- employment
- tax revenue.

1.5 The Department of Trade and Industry provided scenarios of possible exploration and development activity in the area. These are set out in Section 2 of this report.

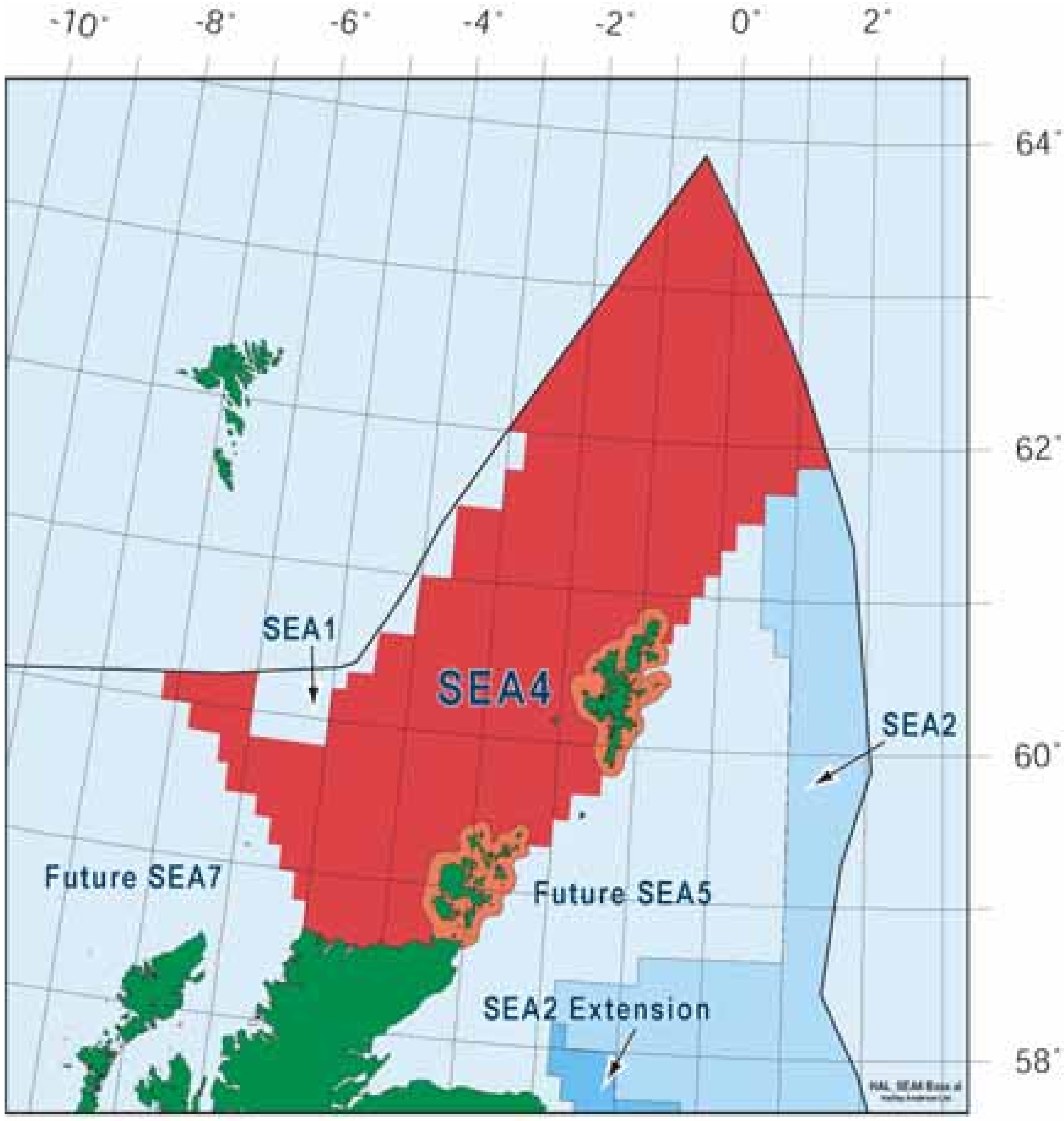
1.6 We converted these scenarios into optimistic and pessimistic scenarios, and then used them to produce forecasts of : oil and gas production (see Section 7); reserves (Section 7); expenditure (Section 8); employment (Section 10); and tax revenues (Section 11).

1.7 There are existing oil and gas industry facilities in the SEA 4 area, which includes the Shetland and Orkney Islands, both of which have been involved in the industry for over 25 years. These existing facilities and activity are described in Section 4, and the implications for them of licensing the SEA 4 area are discussed in Section 9. Section 3 is a brief description of the society and economy of the SEA 4 area.

1.8 The SEA 4 area also has boundaries with both the Faroe Islands and Norway. We considered it necessary to consider the implications of likely activity in these adjacent areas and that is done briefly in Sections 5 and 6.

1.9 We are very grateful for all the information and help provided in the course of our research, particularly by BP and those people interviewed in the Shetland, Orkney and Faroe islands. However, the opinions expressed in this report are those of Mackay Consultants, unless clearly indicated otherwise.

The SEA 4 area



2.0 DTI SCENARIOS

2.1 The Department of Trade and Industry (DTI) provided us with the following scenarios of possible activity in the SEA 4 area, which can be subdivided as follows:

(1) the area of existing and previously licensed acreage;
(2) the northern area which has never been licensed;
(3) the coastal waters close to Shetland and Orkney.

2.2 Sub-area (3) is regarded as having very limited hydrocarbon potential so has been ignored in the scenarios.

Seismic activity

2.3 Area (1) : two 2D seismic surveys (500-1000 km length of 2D seismic lines) and 2-5 3D seismic surveys (500-2500 km^2 of 3D coverage).

2.4 Area (2) : 2-5 2D seismic surveys (1000 – 4000 km length of 2D seismic lines) and 2-5 3D seismic surveys (500-2500 km^2 of 3D coverage).

Exploration wells

2.5 Area (1) : 3-5 wells.

2.6 Area (2) : 1-3 wells.

Developments

2.7 Both areas:

- 1-2 subsea systems tied to existing infrastucture
- 1-2 FPSO (floating production, storage, offloading)
- 8-12 development wells.

3.0 THE SOCIETY AND ECONOMY OF THE SEA 4 AREA

3.1 The SEA 4 area includes the Shetland Islands, Orkney Islands and the north coast of the Highlands, comprising parts of Caithness and Sutherland. The Shetland Islands have a current population of about 22,000, Orkney 19,000 and Caithness and Sutherland 18,000, so the total population of this area is approximately 60,000. The population density is about 20 persons per square kilometre.

3.2 Shetland and Orkney used to be part of Norway and still display features more akin to Scandinavia than Scotland – such as the local dialects and the annual Up Helly-Aa festival in Shetland. Neither island group was ever part of the Gaelic-speaking culture of Highland Scotland, and the later Scottish influence is essentially a lowland one.

3.3 The main transport links – sea and air – are with Aberdeen rather than the Highlands, although there are ferry services across the Pentland Firth linking Orkney and Caithness, and air services with Inverness.

3.4 The north coast of the Highlands is also very different from the rest of the region. Caithness has long been one of the main industrial and manufacturing centres, but Sutherland is much more rural and sparsely populated.

3.5 The main settlements in the area, with their approximate populations, are:

- Shetland : Lerwick 7,270
  Scalloway 1,140
- Orkney : Kirkwall 6,130
  Stromness 1,850
- Caithness : Thurso 7,880.

Population trends

3.6 The population of the Highlands and Islands declined for centuries but there has been a recent upturn. However, most of the increase has taken place in the Inverness area. The 2001 Census of Population statistics show declines in the population of the two island groups and also Caithness and Sutherland.

3.7 Table 3.1 shows the recent population statistics.

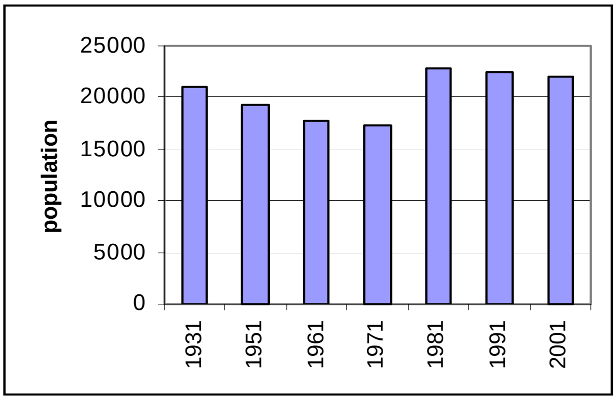
	1991	2001	change	% change
Shetland	22,530	21,960	-570	-2.5
Orkney	19,520	19,220	-300	-1.5
Caithness and Sutherland	*19,500	*18,400	-1,100	-5.6

Source: General Register Office for Scotland, Mid-year Population Estimates; those for Caithness and Sutherland are Mackay Consultants' estimates.

3.8 The populations of all three areas have fallen since 1991. In contrast, that of Highland region increased by +2.5%, although that of Scotland as a whole fell by –0.4%. The relatively large decline in the SEA 4 area is obviously of concern.

3.9 **Shetland** Islands Council's annual "Shetland in Statistics" publication gives the following population statistics for the islands:

1931	21,131
1951	19,352
1961	17,812
1971	17,327
1981	22,766
1991	22,522
2001	21,960



3.10 The population fell substantially between 1931 and 1971. There was a large increase during the 1970s, however, mainly as a result of the advent of the North Sea oil industry, including the construction and operation of the Sullom Voe oil terminal (see next section). Since 1981 the decline appears to have resumed and indeed speeded up in recent years.

3.11 We do not have similar historical statistics for **Orkney** and also **Caithness and Sutherland** but the 2001 Census statistics indicate recent population declines as well, particularly on the north coast of the Highlands.

Economy

3.12 The primary industries – notably fishing and agriculture – have long been the mainstay of the economy of the SEA 4 area and they are still very important in each of the three areas mentioned above. In Shetland the oil industry has become an integral part of the local economy. That is also true, to a much lesser extent, in Orkney and in Caithness and Sutherland.

3.13 "Shetland in Statistics, 2001" gives the following value estimates for the "key sectors" of the **Shetland** economy in 1999:

	£ million
combined fisheries output	139.0
oil production operations	53.7
agriculture	11.8
knitwear	4.9
tourism	14.4
Shetland Islands Council	112.7

3.14 The fisheries sector, which covers fish catching, salmon farming and fish processing, is the single most important sector. The oil industry is also very important. The Shetland Islands Council are the largest employers and most of the employment is now in the service sector, as in the rest of the country.

3.15 The "Orkney Economic Review, 2002" gives the following percentage breakdown of value added (a measure of economic output) in **Orkney** in 1995:

	% of total
Flotta oil terminal	14.7
agriculture	14.5
construction	10.2
distribution	9.8
other private services	8.1

3.16 Most employment is in the service sector, as elsewhere. There is a high level of self-employment, particularly in agriculture. Manufacturing activities include food processing, whisky distilling and the production of jewellery. Fishing and fish farming are much less important than in Shetland.

3.17 **Caithness** has a relatively large manufacturing sector in the context of the Highlands and Islands. The largest employer is the UK Atomic Energy Authority (UKAEA) at the nuclear complex at Dounreay near Thurso. Although the Dounreay complex is now being decommissioned, that work involves billions of expenditure and hundreds of jobs. Agriculture and fishing remain important parts of the local economy, although most of the employment is now in the service sector.

3.18 Most of the fishing activity has transferred from Wick to the port of Scrabster on the north coast, which is also the terminal for the main Orkney-Caithness ferry service. Other communities on the coast include the tourist destination of John O'Groats.

3.19 Moving west, **Sutherland** is much more sparsely populated and has a much smaller economic base. Crofting is still an integral feature of the local economy. Fish farming and tourism are important contributors to local income and employment.

Unemployment

3.20 The latest (April 2003) unemployment figures for the SEA 4 area are:

	number	percentage
Shetland	320	2.4
Orkney	222	1.9
Thurso TTWA	240	-
Sutherland TTWA	363	-

3.21 Unemployment is relatively low in both Shetland and Orkney. The Scottish average was 3.9%.

3.22 The percentage figures for the Thurso and Sutherland travel-to-work areas (TTWA) were not available at the time of writing but they were probably higher than the Scottish average.

4.0 EXISTING FACILITIES AND ACTIVITY IN THE AREA

Existing discoveries

4.1 Some of the SEA 4 area is already licensed and other parts have been licensed but relinquished.

4.2 The SEA 1 area covers a few blocks next to the boundary with the Faroes but for present purposes the SEA 1 area can be combined with SEA 4.

4.3 There are four producing fields in the area, as indicated on the map on the following page:

- Foinaven
- East Foinaven
- Schiehallion
- Loyal.

4.4 A fifth field, Clair, is currently under development and is expected to begin production in late 2004.

4.5 **Foinaven** is in blocks 204/24a, 204/25b and 204/19a, and is operated by BP. It was discovered in October 1992 and production began in November 1997. The original recoverable reserves are estimated at 49.6 million tonnes of oil (370 million barrels) and 6.1 billion cubic metres of gas. The remaining oil reserves are estimated at 30 mt , approximately 60% of the original total. The field is located in 480 metres of water.

4.6 Foinaven was the first West of Shetland field to be developed and is one of the deepest water fields on the UKCS. It uses an FPSO, the Petrojarl Foinaven, with shuttle tankers to take the oil to the Flotta terminal in the Orkney Islands.

4.7 As part of the Phase 2 development of Foinaven, the **East Foinaven** satellite was brought onstream in September 2001. The 36 million barrel satellite uses a five well subsea tieback to the FPSO.

4.8 A constraint on Foinaven oil production was how to handle the gas produced. BP and partners recently undertook what is known as the Magnus Enhanced Oil Recovery (EOR) project, which involves taking gas from Foinaven and Schiehallion to inject in the Magnus reservoir in the East Shetland Basin. This gas pipeline goes via the Sullom Voe terminal. First gas production was on 16 October 2002.

4.9 Foinaven is currently producing about 100,600 barrels per day (bpd) and is expected to produce for another 20 years.

4.10 **Schiehallion** was the next field in the area to be developed, coming onstream in July 1998. It was discovered by BP in October 1993 in block 204/2a, in 425 metres of water.

4.11 The original recoverable reserves are estimated at 79.9 mt oil (600 mb) and 1.1 bcm gas. The remaining oil reserves are estimated at 60 mt , about 75% of the original total.

4.12 The field produces from the purpose built Schiehallion FPSO, with the oil taken by shuttle tankers to the Sullom Voe terminal. It has been developed in phases, with Phase 4 currently underway. This £200 million development includes five subsea wells tied back to the FPSO. Four of these wells are on what is called Schiehallion North Channel and the fifth is on the Craw discovery. First oil from Phase 4 is expected in October 2003.

4.13 The **Loyal** field was developed jointly with Schiehallion and they are often regarded as one field. The Loyal reservoir overlies Schiehallion. It has estimated recoverable reserves of about 85 million barrels.

4.14 Schiehallion and Loyal are currently producing about 137,200 bpd and are expected to produce for another 20 years.

4.15 BP and partners are currently developing the **Clair** field in blocks 206/8, 206/7a and 207/9. It was discovered in 1977 but development work only recently got underway.

4.16 Phase 1 is expected to recover about 290 million barrels of oil, with production start-up in late 2004 rising to 80,000 bpd. It will use a fixed steel platform, rather than a FPSO, with a pipeline to the Sullom Voe terminal in the Shetland Islands. Fifteen production wells and eight injection wells will be drilled. The estimated development cost is £650 million.

4.17 Clair has total estimated reserves of 4 billion barrels but the recovery rate is expected to be relatively low. A decision on Phase 2 (and possible subsequent phases) will be made after the field has begun production. The pipeline will have a capacity of 250,000 bpd so there may be spare capacity to handle oil from any fields in the SEA 4 area.

4.18 The **Solan** discovery (Amerada Hess; block 205/26a) and **Strathmore** (Amerada Hess; block 204/30a) are two discoveries close to Foinaven and Schiehallion which have been put forward under the Satellite Accelerator initiative. Solan was discovered in 1991 and has estimated recoverable oil reserves of 32 million barrels. Strathmore was discovered in 1990 and is probably of a similar size.

4.19 **Suilven** (BP; block 204/19) is another discovery in the area which has yet to be developed. It was discovered by BP in 1996 and Conoco proved an extension into block 204/14. At the time of submitting the application for the Phase 4 development of Schiehallion, BP referred to the possibility of developing Suilven as a subsea satellite. It is about 20 km away and has estimated recoverable reserves of about 50 million barrels.

4.20 The maps in the 2001 “Brown Book” also show gas discoveries in blocks 206/1 (Total), 207/1 (Texaco) and 214/30 (relinquished).

4.21 In the far west in block 154/1 (Enterprise; now part of Shell), just outside the SEA 4 area, there was also a gas discovery.

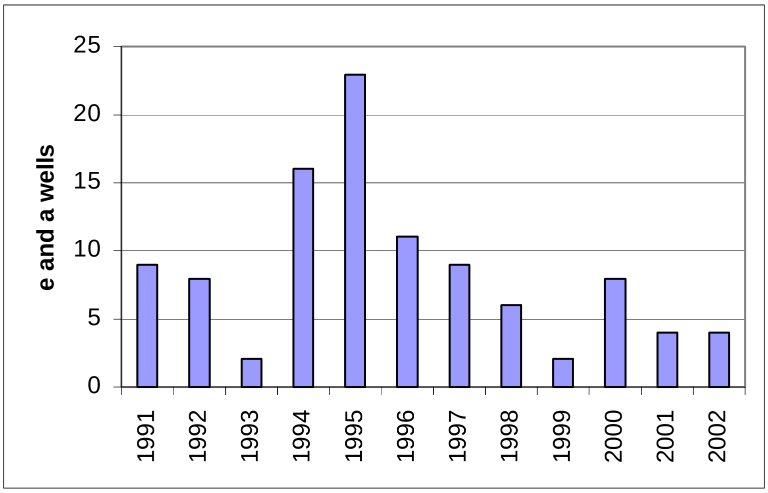
Exploration activity

4.22 Over 180 exploration and appraisal wells have been drilled in what is known as the West of Shetland area to date. The recent statistics are shown in Table 4.1 and the accompanying figure.

Table 4.1
West of Shetland : exploration and appraisal wells

	exploration	appraisal	total
1991	5	4	9
1992	0	8	8
1993	2	0	2
1994	8	8	16
1995	14	9	23
1996	7	4	11
1997	6	3	9
1998	6	0	6
1999	2	0	2
2000	6	2	8
2001	3	1	4
2002	3	1	4

Source: DTI "Brown Book".



4.23 There was a lot of activity in the mid 1990s, with a peak of 23 wells in 1995, but recent drilling has been on a much smaller scale. However, there has been a relatively high level of development drilling in the last few years because of the development of the fields mentioned above.

East of Shetland

4.24 In contrast, the area to the East of Shetland has proved much more prolific.It is outside the SEA 4 area, however. There are currently 29 fields producing oil from there and some associated gas. These fields include some of the "giants" and best-known fields on the UKCS such as Brent, Ninian and Magnus.

4.25 Brent (with estimated recoverable oil reserves of about 2 billion barrels; 270 million tonnes) began production in November 1976 and Ninian (1.2 billion barrels; 160 mt) began production in December 1978. Thus there has been oil production from the East Shetland Basin for over 26 years.

4.26 There are two oil pipelines to the Sullom Voe terminal in the Shetland Islands. The Brent pipeline system currently handles oil from 17 fields and the Ninian pipeline system oil from 12 fields.

4.27 Gas from the East Shetland Basin fields goes via the FLAGS (Far-north Liquids and Associated Gas) system to the St Fergus gas terminal in North East Scotland.

4.28 Further south, oil from 17 fields in the Outer Moray Firth is piped to the Flotta oil terminal in the Orkney Islands. Gas from this area is also piped to St Fergus.

4.29 It should be mentioned that two of the fields in the East Shetland Basin – Murchison and Statfjord – straddle the UK/Norwegian boundary line. There are also other Norwegian fields in this area close to the international boundary.

4.30 An important feature of the East of Shetland area is that oil production has passed its peak and is now declining. The implications of that are discussed below.

Onshore facilities : Shetland

4.31 Shetland has had over 30 years' involvement with the UKCS oil and gas industry and there is a well-established range of existing infrastructure which any discoveries in the SEA 4 area could use. We visited both Shetland and Orkney in the course of this study.

4.32 The existing facilities include:

- the Sullom Voe oil terminal
- Scatsta and Sumburgh airports
- a supply base in Lerwick
- other supporting facilities.

4.33 The Sullom Voe oil terminal was built in the 1970s to handle oil from the East Shetland Basin fields. First production from the Dunlin field was in November 1976, so the terminal has been in operation for over 26 years. It includes storage tanks, processing facilities and export jetties. Oil from the fields is stabilised, stored and loaded into tankers which go to UK refineries, the USA and other export markets.

4.34 The terminal is situated at Calback Ness on the shores of Sullom Voe on a site of approximately 400 hectares (1,000 acres). BP operate the terminal on behalf of the companies participating in the Brent and Ninian pipeline systems. It currently has a throughput design capacity of 1.2 million barrels of crude oil per day and reached a peak in 1984 with a total receipt of just over 439 million barrels.

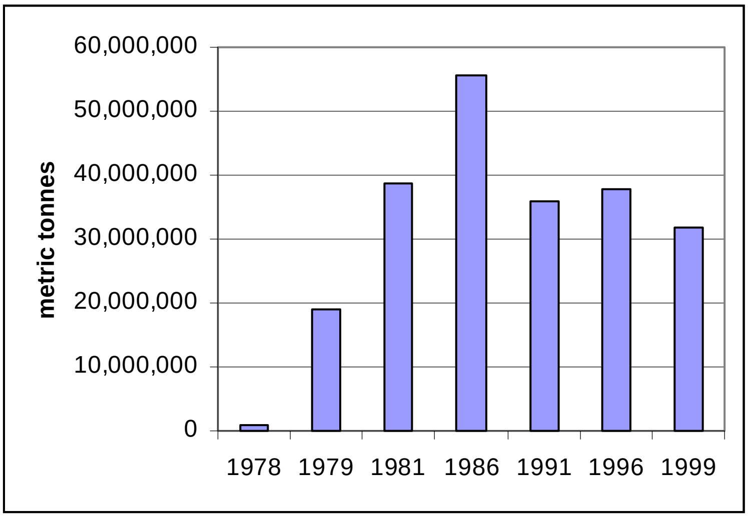
4.35 The throughput at Sullom Voe has declined substantially in recent years as a consequence of falling production from the fields in the East Shetland Basin. Table 4.2 below gives the historical statistics.

4.36 Peak throughput was in 1986 when over 55 million tonnes of oil were handled, averaging 1,146,647 barrels per day (bpd). The current throughput is about 500,000 bpd so there is substantial excess capacity.

Table 4.2
Sullom Voe terminal oil throughput
(metric tonnes)

	Brent system	Ninian system	Schiehallion	Total
1978	856,991	92,186	0	949,177
1979	10,367,579	8,555,865	0	18,923,444
1981	23,116,490	15,545,240	0	38,661,730
1986	38,692,099	16,875,047	0	55,567,146
1991	20,263,701	15,576,512	0	35,840,213
1996	23,332,990	14,368,498	0	37,701,488
1999	19,823,481	7,076,318	5,112,218	32,012,017
2002	?	?	?	?

Source: "Shetland in Statistics, 2001" (published by the Development Department of the Shetland Islands Council).



4.37 The addition of oil from Schiehallion has slowed down the decline but not reversed it. The decline is expected to continue. Production from the East Shetland Basin could end between 2010 and 2015.

4.38 Sullom Voe would be delighted to handle oil from new discoveries in the SEA 4 area. The implications of that are discussed in Section 8 of this report.

4.39 BP are currently undertaking changes at Sullom Voe to reduce costs and make the terminal more competitive. There are currently three oil processing trains but that will be reduced to two by mid 2003 and one by the end of 2004.

4.40 The gas plant may be closed down in the foreseeable future. The liquid petroleum gases (LPG) are currently exported by tanker but in future will go to Magnus as part of the enhanced oil recovery (EOR) project there.

4.41 The utilisation of the storage tanks is about one third of the peak capacity. However, some of the tanks are now dedicated to Schiehallion oil which is not mixed with the other crudes. Schiehallion is a heavy oil and the tanks require heating.

4.42 Clair oil will similarly have dedicated tanks.

4.43 Three of the four existing jetties are in operation and the other one has been “soft retired”. One jetty is currently dedicated to Schiehallion, handling about 250 vessels per year.

4.44 Current employment at the terminal averages about 390 (BP 240 plus 150 contractors), with some seasonal variations. That number will fall because BP are transferring most of the management and administration functions from Sullom Voe to Aberdeen. The closure of the gas plant would reduce employment further.

4.45 There is similar spare capacity among the tugs operated by Shetland Towage and the facilities provided by Shetland Islands Council. Shetland Towage employ about 60 people and SIC 60-70 at Sullom Voe.

4.46 Employment at Sullom Voe peaked at around 1,100 people in 1991. The current total is about 520.

4.47 Shetland has two airports at Sumburgh and Scatsta handling oil-related traffic. Sumburgh, which is owned and operated by Highlands and Islands Airports Ltd (HIAL), traditionally handled most of this traffic but in the late 1990s the oil companies transferred most of tit to Scatsta, near Sullom Voe, because of dissatisfaction at the high costs of using Sumburgh. There is consequently substantial spare capacity at Sumburgh.

4.48 Some of the companies fly their platform and rig crews by fixed-wing planes between Aberdeen and Shetland, with helicopters operating from Shetland. Some fly helicopters direct from/to Aberdeen, bypassing Shetland. BP, for example, do that for the West of Shetland fields.

4.49 For many years Chevron used an airport on Unst to minimise the helicoper times but they stopped doing that a few years ago.

4.50 At one time there were six separate oil supply bases in Shetland but now there is only one at Greenhead, just outside Lerwick. It is considerably underutilised at the present time.

4.51 The supply bases in Shetland suffered when the operators decided to supply the East of Shetland fields directly from Peterhead and Aberdeen, rather than using Shetland which involved doublehandling costs. Thus Shetland gets very little of the normal supply boat traffic, except during bad weather.

4.52 However, Shetland does attract some "heavy traffic" during the development period for new fields such as Clair. The Lerwick base, for example, handled the pipes for the gas pipeline from the West of Shetland fields to Magnus and hopes to win a similar contract for the Clair pipeline.

4.53 Diving support vessels and standby ships also use Shetland for crew changes. Both Lerwick and Scalloway (on the west side) harbours benefit from this business.

4.54 Other oil-related businesses in Shetland include:

- SBS Logistics
- Shetland Oil Tools, who handle drill cuttings
- Malakoff and Moore, engineers.

4.55 There were many other oil-related businesses in the 1980s and 1990s but they have since closed down or left the islands. Nevertheless, there remains considerable industry expertise among the local labour force and the local business community.

Onshore facilities : Orkney

4.56 We also visited Orkney in the course of the study. The only significant oil-related facility in Orkney is the Flotta oil terminal, which is similar with the Sullom Voe terminal in Shetland. It was initially built to handle oil from the Piper field in the Outer Moray Firth and currently handles oil from 16 fields in that area.

4.57 BP also use Flotta to handle oil from the Foinaven field, using shuttle tankers rather than a pipeline.

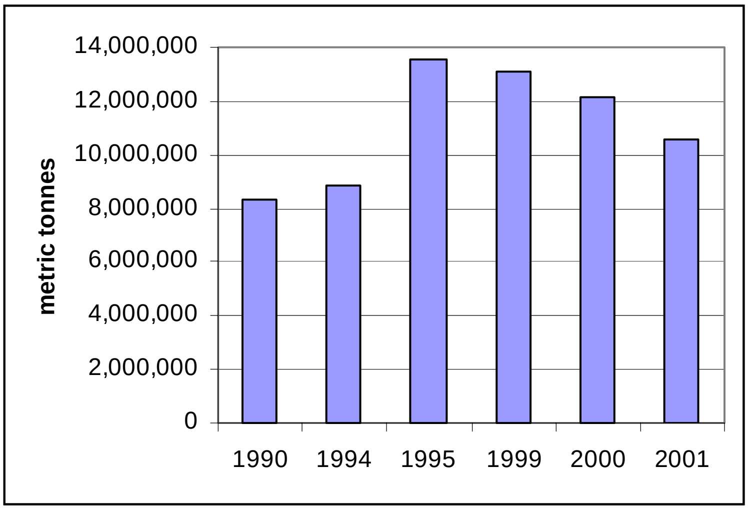
4.58 The terminal was originally built by Occidental and later operated by Elf. Talisman are now the operators.

4.59 Throughput at Flotta has also been declining as a consequence of falling production from the Moray Firth fields. Table 4.3 gives some historical statistics.

Table 4.3
Flotta terminal : oil throughput
(metric tonnes)

	North Sea crude	Foinaven	total
1990	8,336,225	0	8,336,225
1994	8,860,242	0	8,860,242
1995	13,529,630	0	13,529,630
1999	9,568,002	3,574,343	13,142,345
2000	8,378,324	3,738,239	12,116,563
2001	6,824,997	3,775,666	10,600,663
2002	?	?	?

Source: "Orkney Economic Review, 2002" (published by the Development Department, Orkney Islands Council).



4.60 Peak throughput was recorded in 1995. Since then there has been a substantial fall in oil from the North Sea fields but the oil from Foinaven has slowed down the decline.

4.61 The terminal's capacity is about 400,000 bpd. The Moray Firth fields currently use about 125,000 bpd of that and Foinaven about 100,000 bpd.

4.62 Talisman have mothballed a gas plant and a process plant but these could be recommissioned if required.

4.63 Flotta currently employs about 230 people, mainly contractors. Peak employment in the Occidental days was about 450.

Other onshore facilities

4.64 The southern boundary of the SEA 4 area is the northern coast of the Highlands. It includes the port of Scrabster which has been used by seismic vessels, supply boats and other oil-related traffic in the past, although recent use has been very sporadic. That is also true of Wick in Caithness and Stornoway in the Western Isles, which is close to the western boundary of the SEA 4 area.

4.65 As indicated above, the existing West of Shetland fields are mainly serviced from Aberdeen and to a lesser extent Peterhead on the Scottish mainland. There is a wide range of oil-related services in the Aberdeen area.

4.66 In the Highlands there were six platform fabrication yards at one time which built many of the steel and concrete platforms in use on the UKCS. Now there is only one yard in operation – at Nigg on the Cromarty Firth – and it has been without a large order for two years. McDermott closed their Ardersier yard recently and the small Arnish yard near Stornoway is being converted to build turbines for wind farms.

4.67 There are two active pipeline fabrication yards in the Highlands – at Wester in Caithness and at Evanton on the Cromarty Firth. Invergordon on the Cromarty Firth is the main centre in the UK for the inspection, repair and maintenance (IRM) of mobile drilling rigs.

4.68 All of these existing facilities, plus others elsewhere, would obviously be keen to win business from any developments in the SEA 4 area.

5.0 ACTIVITY IN FAROESE WATERS

5.1 The northern and western boundaries of the SEA 4 area are also the international boundaries with the Faroe Islands. It is therefore necessary to take account of what is happening there. We also made a visit to the Faroes as part of this study.

5.2 The boundaries with the UK were agreed in 1999 after years of negotiations. There were initially high hopes in the Faroes because of the proximity to the Foinaven and Schiehallion discoveries and the belief that the geological structures in Faroese waters were similar. However, results to date have been disappointing.

5.3 A licence round began in 2000. Seven licences were awarded in August 2000 to groups led by: (1) Amerada Hess; (2) Agip; (3) Statoil; (4) BP; (5) Agip; (6) Statoil; and (7) Anadarko. These are all close to the SEA 4 area and are shown on the map on the following page. Three exploration wells were drilled in 2001 by Statoil, BP and Amerada Hess. The first two were basically dry but the Amerada Hess well in block 6004/16 (licence 001) encountered "light oil and gas in a 170 metres gross interval of hydrocarbons". However, the well was not tested because of bad weather.

5.4 Agip were due to drill a well in 2002 but the Faroes Government agreed that could be postponed until summer 2003. A spokesman for the Faroese Petroleum Ministry said that "the results of the exploration wells on the Faroe Shelf last summer did not turn out quite as expected. Therefore an extensive and demanding task lies ahead with careful studies of the seismic data, the geological models and the technical interpretation methods applied to the Faroese area to date". The presence of a thick blanket of basalt makes imaging difficult.

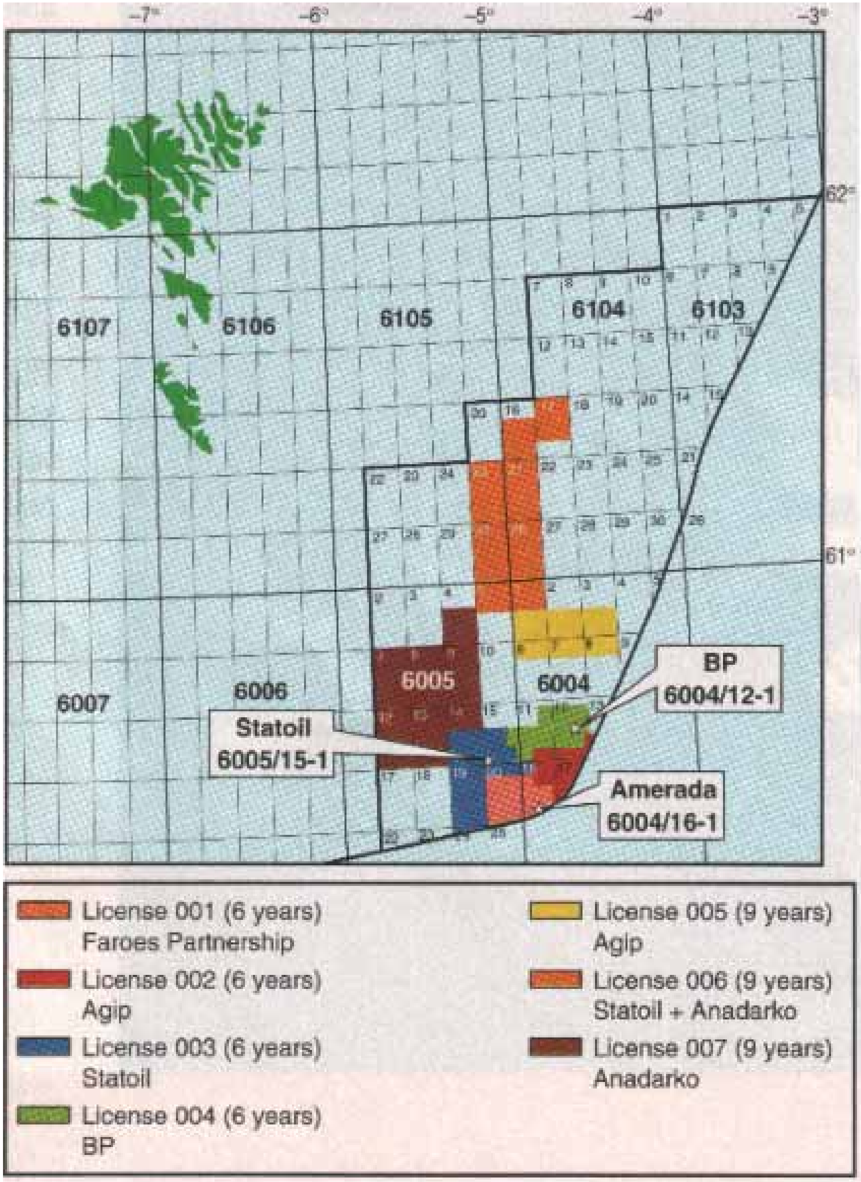
5.5 A subsequent well was drilled by Amerada Hess in UK waters in block 204/16, close to the boundary with the Faroes, but that too was disappointing. Press reports suggested that the well was regarded as an appraisal of the Marjun discovery.

5.6 The Agip well to be drilled in summer 2003 could obviously be very important for the future of the petroleum industry. After that well there are four outstanding well commitments in the licences but the companies seem reluctant to drill them. The Ministry of Petroleum told us that BP may drill in 2004, Statoil in 3Q 2004/2005 and Amerada in 2005.

5.7 The three other licences do not have well commitments, although there are agreed programmes of seismic, aeromagnetic and other surveys, and these commitments have all been met.

5.8 The Ministry of Petroleum gave us a presentation which summarised the results of the first two years of exploration as:

- none of the main targets turned out the way it was predicted
- promising seismic signatures proved to be related to other geological factors than hydrocarbon accumulations
- presence of oil and gas in this part of the geological column gives hope that hydrocarbons may be accumulated elsewhere in this level
- discovery made in a deeper level - which was not predicted - opens up for new possibilities in the future.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Statoil
6005/15-1
Amerada
6004/16-1
License 001 (6 years)
Faroes Partnership
License 002 (6 years)
Agip
License 003 (6 years)
Statoil
License 004 (6 years)
BP
License 005 (9 years)
Agip
License 006 (9 years)
Statoil + Anadarko
License 007 (9 years)
Anadarko

5.9 The implications for the future were stated to be:

- increase the understanding of the geology and hydrocarbon potential in the area – in order to optimise the planning of future exploration work, co-operation and openness between companies
- need to look both shallow and deep with an open mind
- keep in mind and take into consideration the experience gained from the West of Shetland (WoS) area, but
- we are not dealing with a mere extension of the WoS area.

5.10 If one or more discoveries are made in Faroese waters it is likely that they will make use of either the Sullom Voe terminal in Shetland or the Flotta terminal in Orkney. The Faroese have not given any serious consideration to the construction of such a terminal there.

5.11 The general expectation is that any oil discovery would be developed with a floating production, storage and offloading system (FPSO), as has been done with Foinaven and Schiehallion, with shuttle tankers going to Sullom Voe or Flotta. Use could also be made of the Clair oil pipeline which is expected to have spare capacity.

5.12 Even less thought has been given to how a gas discovery would be developed. However, the new gas pipeline from Foinaven and Schiehallion to Magnus via Sullom Voe could be used.

5.13 Thus although exploration activity in Faroese waters has brought disappointing results so far, there remains the possibility of developments which could impact on activity in the SEA 4 area. In particular, any commercial discoveries offshore the Faroes are likely to make use of adjacent UK infrastructure such as the terminals and possibly pipelines.

6.0 ACTIVITY IN NORWEGIAN WATERS

6.1 The north-eastern boundary of the SEA 4 area is part of the international boundary with Norway. As with the Faroe Islands, therefore any activity in the adjacent Norwegian sector could have implications for the SEA 4 area.

6.2 However, there has been no significant exploration activity and no commercial discoveries in this part of the Norwegian continental shelf to date and we do not expect any in the near future.

6.3 The most northerly discoveries in the Norwegian sector of the North Sea are Murchison, which straddles the UK/Norwegian boundary line south of SEA 4, and Snorre. Oil from both parts of the Murchison field is piped to the Sullom Voe terminal in the Shetland Islands and the gas is piped to the St Fergus terminal in North East Scotland.

6.4 There are fields in production further north in what is known as the Norwegian Sea but they are a long way from the SEA 4 area. These fields include Asgard, Draugen and Heidrun.

6.5 Thus we do not foresee any activity in the near future in that part of the Norwegian Continental Shelf which borders on the SEA 4 area.

7.0 IMPLICATIONS FOR OIL AND GAS PRODUCTION AND RESERVES

7.1 The scenarios provided by the DTI included for both areas

- 1-2 subsea systems tied to existing infrastructure
- 1-2 FPSO
- 8-12 development wells.

These give a range of 2-4 FPSO in total and 2-4 subsea systems, with associated development wells.

7.2 As mentioned earlier we have converted the DTI scenarios into a "pessimistic scenario" and an "optimistic" one. The "pessimistic" scenario used in this report is based on 2 FPSO and 2 subsea developments, and the "optimistic" scenario is based on 4 FPSO and 4 subsea developments.

Oil production

7.3 According to the DTI oil and gas website at the time of writing (May 2003) there were 18 floating production systems on the UKCS. The range of peak throughputs appears to have been from about 27,500 bpd oil (Blenheim; now ceased production) to 140,000 bpd (Schiehallion), with an average of about 40,000 bpd. Foinaven appears to have the second largest capacity of about 120,000 bpd.

7.4 For the pessimistic scenario we have assumed that there will be two FPSOs with 50,000 bpd capacity each, which would give peak oil production of 100,000 bpd.

7.5 For the optimistic scenario we have assumed two larger FPSOs with 100,000 bpd capacity each, which would add another 200,000 bpd peak capacity, giving an overall total of 300,000 bpd.

7.6 In addition there will be production from the subsea developments. For the pessimistic scenario we have assumed that both will produce 10,000 bpd at peak, a total of 20,000 bpd, and for the optimistic scenario we have assumed that both will produce 20,000 bpd at peak, a total of 40,000 bpd. Together the four subsea developments could therefore produce up to 60,000 bpd.

7.7 The actual increase in oil production would depend on the timing of the developments. Table 7.1 on the following page sets out possible scenarios.

7.8 We believe that these scenarios are reasonable. They are consistent with actual production from Foinaven and Schiehallion, including the subsea satellites.

7.9 For the pessimistic scenario, we have assumed that production from the first field, FPSO(1), would begin in 2010 at an average of 20,000 bpd and be maintained at 50,000 bpd for three years before falling each year at 5,000 bpd. The final production would be in 2022, after thirteen years.

7.10 The second FPSO(2) would begin two years later in 2012 and have an identical profile, ending production in 2024.

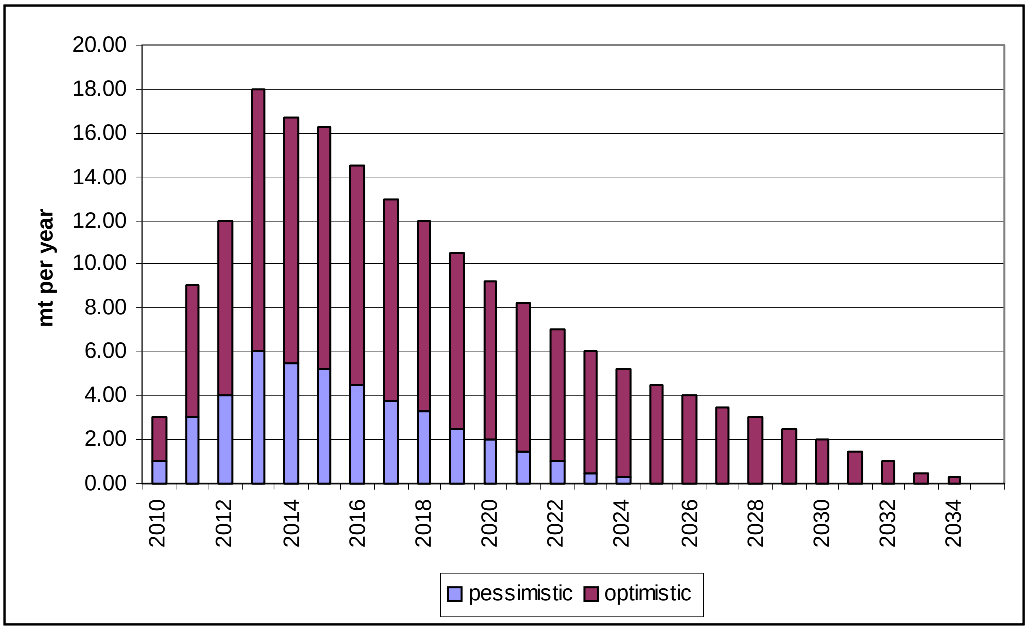
Table 7.1(a)
Oil production scenarios from SEA 4 fields
(thousands of barrels per day)

	Pessimistic					**Optimistic**					
Year	FPSO(1)	FPSO(2)	SS(1)	SS(2)	Sub total	FPSO(3)	FPSO(4)	SS(3)	SS(4)	Sub total	Total
2010	20				20	40				40	60
2011	50		10		60	100		20		120	180
2012	50	20	10		80	100	40	20		160	240
2013	50	50	10	10	120	100	100	20	20	240	360
2014	45	50	5	10	110	95	100	10	20	225	335
2015	40	50	5	10	105	90	100	10	20	220	325
2016	35	45	5	5	90	85	95	10	10	200	290
2017	30	40		5	75	80	90	5	10	185	260
2018	25	35		5	65	75	85	5	10	175	240
2019	20	30			50	70	80	5	5	160	210
2020	15	25			40	65	75		5	145	185
2021	10	20			30	60	70		5	135	165
2022	5	15			20	55	65			120	140
2023		10			10	50	60			110	120
2024		5			5	45	55			100	105
2025						40	50			90	90
2026						35	45			80	80
2027						30	40			70	70
2028						25	35			60	60
2029						20	30			50	50
2030						15	25			40	40
2031						10	20			30	30
2032						5	15			20	20
2033							10			10	10
2034							5			5	5
2035											

Table 7.1(b)
Oil production scenarios from SEA 4 fields
(millions of tonnes per year)

	Pessimistic					Optimistic					
Year	FPSO(1)	FPSO(2)	SS(1)	SS(2)	Sub total	FPSO(3)	FPSO(4)	SS(3)	SS(4)	Sub total	Total
2010	1.00				1.00	2.00				2.00	3.00
2011	2.50		0.50		3.00	5.00		1.00		6.00	9.00
2012	2.50	1.00	0.50		4.00	5.00	2.00	1.00		8.00	12.00
2013	2.50	2.50	0.50	0.50	6.00	5.00	5.00	1.00	1.00	12.00	18.00
2014	2.25	2.50	0.25	0.50	5.50	4.75	5.00	0.50	1.00	11.25	16.75
2015	2.00	2.50	0.25	0.50	5.25	4.50	5.00	0.50	1.00	11.00	16.25
2016	1.75	2.25	0.25	0.25	4.50	4.25	4.75	0.50	0.50	10.00	14.50
2017	1.50	2.00		0.25	3.75	4.00	4.50	0.25	0.50	9.25	13.00
2018	1.25	1.75		0.25	3.25	3.75	4.25	0.25	0.50	8.75	12.00
2019	1.00	1.50			2.50	3.50	4.00	0.25	0.25	8.00	10.50
2020	0.75	1.25			2.00	3.25	3.75		0.25	7.25	9.25
2021	0.50	1.00			1.50	3.00	3.50		0.25	6.75	8.25
2022	0.25	0.75			1.00	2.75	3.25			6.00	7.00
2023		0.50			0.50	2.50	3.00			5.50	6.00
2024		0.25			0.25	2.25	2.75			5.00	5.25
2025						2.00	2.50			4.50	4.50
2026						1.75	2.25			4.00	4.00
2027						1.50	2.00			3.50	3.50
2028						1.25	1.75			3.00	3.00
2029						1.00	1.50			2.50	2.50
2030						0.75	1.25			2.00	2.00
2031						0.50	1.00			1.50	1.50
2032						0.25	0.75			1.00	1.00
2033							0.50			0.50	0.50
2034							0.25			0.25	0.25
2035											

Figure 7.1
Oil production scenarios from SEA 4 fields
(millions of tonnes per year)



7.11 The first subsea field SS(1) would commence production one year after FPSO(1) in 2011 and produce at 10,000 bpd for three years and 5,000 bpd for the next three years, ceasing production in 2016. The second subsea field SS(2) would have an identical profile apart from beginning and ending production two years later.

7.12 SS(1) could be tied back to FPSO(1) or any of the existing fields – Foinaven, Schiehallion or Clair – as could SS(2). The impacts would be little different.

7.13 For the optimistic scenario, we have assumed that FPSO(3) would begin production in 2010 at 40,000 bpd, rising to 100,000 bpd before falling by 5,000 bpd each year. On these assumptions the field's lifetime will be longer than that of FPSO(1) and it will continue producing until 2032.

7.14 FPSO(4) would have an identical profile, except for starting two years later in 2012 and ending two years later in 2034.

7.15 Subsea (3) would begin production in 2011 at 20,000 bpd, falling to 5,000 bpd in the final year 2019. Subsea (4) would be identical, except for starting two years later in 2013 and ending two years later in 2021. These two fields would produce more oil and over a longer period than SS(1) and SS(2).

7.16 Table 7.1 and Figure 7.1 show that under the pessimistic scenario the SEA 4 area would produce up to 120,000 bpd over fifteen years. Total production from the four fields would be 44.0 million tonnes or 330 million barrels (at 7.5 barrels = 1 tonne).

7.17 Under the optimistic scenario the SEA 4 area would produce an additional 129.0 million tonnes (970 million barrels) at up to 240,000 bpd. Total production under this scenario would be 173.0 million tonnes (1300 million barrels) with peak production of 360,000 bpd.

Comparisons with total UKCS oil production

7.18 UKCS oil production in 2002 was approximately 111.7 million tonnes (averaging 2.2 million barrels per day). There seems general agreement that the peak has passed and that the future is one of slow decline.

7.19 It is very difficult to forecast the rate of decline. In Table 7.2 on the following page and Figure 6.2 we have made the simple assumption that there will be an annual average decline of –5.0%. In reality there will be fluctuations from year to year but for the purposes of this study we believe it is a reasonable assumption.

7.20 The Rest of UKCS row of Table 7.2 shows oil production declining slowly but steadily from 111.7 million tonnes (223,400 bpd) in 2002 to 20.6 million tonnes (41,200 bpd) by 2035.

7.21 SEA 4 production is assumed to start in 2010 by which time the Rest of UKCS production would have fallen to 74.1 mt, down –35% on the 2002 level. Under the pessimistic scenario, total production will continue to decline but SEA 4 production will slow down that decline. For example, 2013 production of 69.5 million tonnes would be +9.5% higher than the Rest of UKCS total.

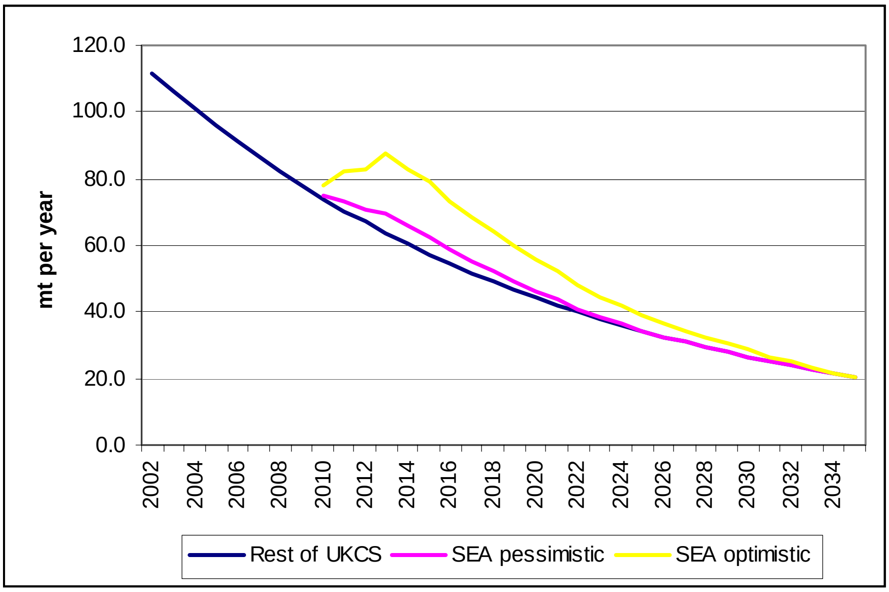
7.22 The optimistic SEA 4 scenario gives a significantly different picture, as illustrated in Figure 7.2. Production would actually increase during the five years 2009-13 before the decline resumed. Indeed for the seven years 2009-15 production would be relatively stable at around 80 mt per year (160,000 bpd).

7.23 In the peak year 2013 total production would be +37.8% higher than it would have been without SEA 4 oil. That percentage addition would decline over time, as indicated in the table and figure.

Table 7.2
Forecasts of UKCS oil production
(million tonnes per year)

year	Rest of UKCS	SEA 4 pessimistic	Sub-total	SEA 4 optimistic	Total
2002	111.7	-	111.7	-	111.7
2003	106.1	-	106.1	-	106.1
2004	100.8	-	100.8	-	100.8
2005	95.8	-	95.8	-	95.8
2006	91.0	-	91.0	-	91.0
2007	86.4	-	86.4	-	86.4
2008	82.1	-	82.1	-	82.1
2009	78.0	-	78.0	-	78.0
2010	74.1	1.0	75.1	3.0	78.1
2011	70.4	3.0	73.4	9.0	82.4
2012	66.9	4.0	70.9	12.0	82.9
2013	63.5	6.0	69.5	18.0	87.5
2014	60.4	5.5	65.9	16.8	82.7
2015	57.3	5.3	62.6	16.3	78.9
2016	54.5	4.5	59.0	14.5	73.5
2017	51.7	3.8	55.5	13.0	68.5
2018	49.2	3.3	52.5	12.0	64.5
2019	46.7	2.5	49.2	10.5	59.7
2020	44.4	2.0	46.4	9.3	55.7
2021	42.2	1.5	43.7	8.3	52.0
2022	40.0	1.0	41.0	7.0	48.0
2023	38.0	0.5	38.5	6.0	44.5
2024	36.1	0.3	36.4	5.3	41.7
2025	34.3	-	34.3	4.5	38.8
2026	32.6		32.6	4.0	36.6
2027	31.0	-	31.0	3.5	34.5
2028	29.4	-	29.4	3.0	32.4
2029	28.0	-	28.0	2.5	30.5
2030	26.6	-	26.6	2.0	28.6
2031	25.2	-	25.2	1.5	26.7
2032	24.0	-	24.0	1.0	25.0
2033	22.8	-	22.8	0.5	23.3
2034	21.6	-	21.6	0.3	21.9
2035	20.6	-	20.6	-	20.6

Figure 7.2
Forecasts of UKCS oil production



Gas production

7.24 Gas production from the SEA 4 area is more difficult to predict and analyse. Both the East Shetland Basin and the West of Shetland area appear to be much more oil prone than gas. That is in marked contrast to the Southern North Sea.

7.25 Generally, the further north you go on the UKCS the more likely you are to find oil than gas. There have been exceptions to this generalisation, of course, such as the giant Frigg gas field.

7.26 Nevertheless, associated gas has been found in most of the fields in the East Shetland Basin and the West of Shetland area. Most of the gas produced from the latter goes via the FLAGS pipeline to the St Fergus terminal in North East Scotland. FLAGS throughput in 2002 was approximately 12.5 billion cubic metres, which was about 11% of the UKCS gas total.

7.27 Until recently there was no outlet for gas from the West of Shetland fields. However, BP and partners have recently laid a gas pipeline from Foinaven and Schiehallion via the Sullom Voe Terminal to the Magnus field in the East Shetland Basin as part of the Magnus Enhanced Oil Recovery (EOR) project. Gas production from Foinaven and Schiehallion began on 16 October 2002.

7.28 Most of the gas will be reinjected into the Magnus reservoir. Some of it will be used for power generation at Sullom Voe and any surplus will go via the FLAGS pipeline to St Fergus.

7.29 BP informed us that there is unlikely to be any spare capacity in the Foinaven-Sullom Voe leg of the pipeline for the foreseeable future, so it is unlikely that any discoveries in the SEA 4 area could make use of it.

7.30 There is spare capacity, however, in the Sullom Voe-Magnus leg of the pipeline, which we understand can handle up to 120 million cubic feet per day (mmcfd). BP and partners are currently (May 2003) undertaking a feasibility study of piping gas from Clair to Magnus via Sullom Voe.

7.31 It is possible therefore that a SEA 4 field could use the Clair gas pipeline to export gas or build a separate line to Sullom Voe or a separate line to Magnus/East Shetland Basin. However, the economic viability of any gas discovered in the SEA 4 area must be very uncertain at the present time. For the pessimistic scenario we have assumed no gas production.

7.32 Nevertheless, for the optimistic scenario we have assumed some gas production, as indicated in Table 7.3, from the two larger fields using FPSOs. The basic assumption is that the SEA 4 area will produce 50 billion cubic metres of gas over 20 years at an annual average of 2.5 bcm. Peak annual production would be 3.0 bcm. The production profile of a gas field is usually much flatter and stable than that of an oil field.

7.33 UKCS gas production was about 114.1 billion cubic metres (bcm) in 2002. It has grown rapidly in recent years, reaching a peak of 115.8 bcm in 2000. The general expectation is that it will also decline slowly from now on, as with offshore oil production.

7.34 In Table 7.3 we have assumed that UKCS gas output will decline at an annual average of –3.0% to 2010 and by –5.0% after that year. The annual figures are shown in the table and in Figure 7.3.

7.35 SEA 4 gas production would begin in 2010. At peak it would contribute about 5.7% of the total. That percentage would rise steadily in the first ten years or so as the rest of the UKCS output continues to decline.

7.36 However, unlike the oil scenarios, SEA 4 gas will be insufficient to reverse the decline in total gas production. It will simply slow down the rate from 2010 onwards.

Figure 7.3
Forecasts of UKCS gas production

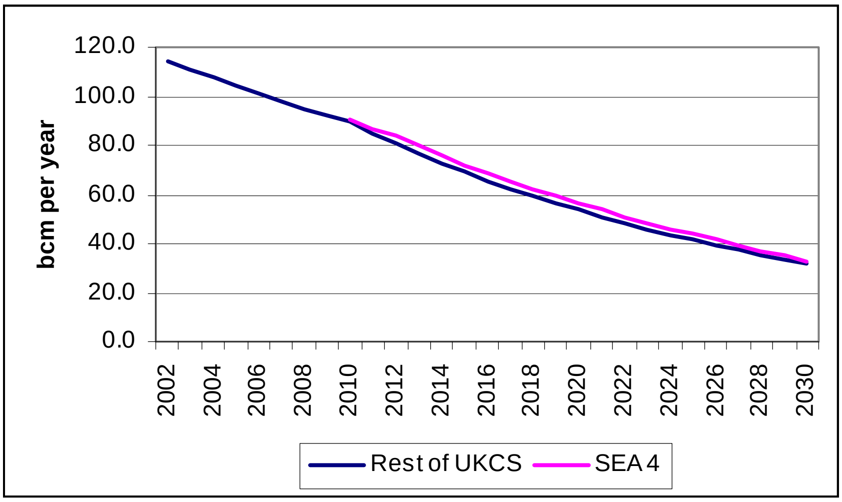


Table 7.3
Forecasts of UKCS gas production
(billion cubic metres per year)

year	Rest of UKCS	SEA 4	total	SEA 4 as % of total
2002	114.1	-	114.1	-
2003	110.7	-	110.7	-
2004	107.4	-	107.4	-
2005	104.1	-	104.1	-
2006	101.0	-	101.0	-
2007	98.0	-	98.0	-
2008	95.0	-	95.0	-
2009	92.2	-	92.2	-
2010	89.4	1.0	90.4	1.1
2011	84.9	2.0	86.9	2.3
2012	80.7	3.0	83.7	3.6
2013	76.6	3.0	79.9	3.8
2014	72.8	3.0	75.8	4.0
2015	69.2	3.0	72.2	4.2
2016	65.7	3.0	68.7	4.4
2017	62.4	3.0	65.4	4.6
2018	59.3	3.0	62.3	4.8
2019	56.3	3.0	59.3	5.1
2020	53.5	3.0	56.5	5.3
2021	50.9	3.0	53.9	5.6
2022	48.3	2.5	50.8	4.9
2023	45.9	2.5	48.4	5.2
2024	43.6	2.5	46.1	5.4
2025	41.4	2.5	43.9	5.7
2026	39.3	2.0	41.3	4.8
2027	37.4	2.0	39.4	5.1
2028	35.5	1.0	36.5	2.7
2029	33.7	1.0	34.7	2.9
2030	32.0	1.0	33.0	3.0

Oil and gas reserves

7.37 Our reserve assumptions for the fields in the scenarios provided by the DTI are:

	Oil (mt)	Gas (bcm)
Pessimistic scenario		
FPSO(1)	19.75	-
FPSO(2)	19.75	-
SS(1)	2.25	-
SS(2)	2.25	-
sub-total	44.00	-
Optimistic scenario		
* the above plus		
FPSO(3)	64.50	25.0
FPSO(4)	64.50	25.0
SS(3)	5.25	-
SS(4)	5.25	-
sub-total	139.50	50.0
totals	183.50	50.0

7.38 According to the 2001 “Brown Book” the total initially recoverable reserves of oil on the UKCS (as at 31 December 2000) were (in million tonnes):

	proven	probable	possible	maximum
Initially recoverable	3200	380	480	4060
Cumulative production	2570	-	-	-
Remaining reserves	**630**	**380**	**480**	**1490**

7.39 The 1490 mt remaining are 36.7% of the maximum estimate. The 630 mt remaining proven are 19.7% of the initial proven reserves. There seems little doubt that most of the oil on the UKCS has already been developed.

7.40 Our optimistic scenario assumption of 183.5 mt oil in the SEA 4 area is 12.3% of the 1490 mt maximum remaining reserves and the pessimistic assumption of 44.0 mt is 2.9%. We believe that these are therefore reasonable assumptions about oil reserves in the SEA 4 area.

7.41 We have also assumed that 50 bcm of gas will be recovered from the SEA 4 fields.

7.42 The 2001 “Brown Book” estimates for UKCS gas reserves (in billion cubic metres) are:

	proven	probable	possible	maximum
Initially recoverable	2255	460	430	3145
Cumulative production	1518	-	-	-
Remaining reserves	**735**	**460**	**430**	**1630**

7.43 The 1630 bcm remaining are 51.8% of the maximum estimate. The 735 remaining proven are 32.6% of the initial proven reserves. These percentages are higher than for the oil reserves.

7.44 Our assumption of 50 bcm gas in the SEA 4 area is just 3.1% of the 1630 bcm maximum remaining reserves and 11.6% of the 430 bcm possible estimate. Given that the evidence to date indicates that the SEA 4 area is much more oil prone than gas, we also believe that our assumptions about gas reserves in the area are reasonable.

8.0 IMPLICATIONS FOR CAPITAL, OPERATING AND DECOMMISSIONING EXPENDITURE

Capital expenditure

8.1 For the pessimistic scenario we have assumed that four fields will be developed:

- FPSO(1) 19.5 mt/150 mb oil
- FPSO(2) 19.5 mt/150 mb oil
- Subsea(1) 2.25 mt/17 mb oil
- Subsea(2) 2.25 mt/17 mb oil.

8.2 For the optimistic scenario we have assumed the above plus four other fields:

- FPSO(3) 64.5 mt/500 mb oil + 25.0 bcm gas
- FPSO(4) 64.5 mt/500 mb oil + 25.0 bcm gas
- Subsea(3) 5.25 mt/40 mb oil
- Subsea(4) 5.25 mt/40 mb oil.

8.3 The best guide to development/capital expenditure in the SEA 4 area is probably the existing Foinaven and Schiehallion fields, both of which use FPSO systems.

8.4 According to BP, Foinaven cost about £700 million to develop, with the following breakdown:

	£ million
project management	52
drilling	249
subsea	335
technical support	6
insurance	11
UAP contingency	26
total	679

8.5 This cost excludes the FPSO, however, which is leased from Golar Nor. If that were included the capital cost would have exceeded £1 billion.

8.6 According to BP, the development cost of Schiehallion was just over £1 billion, disaggregated as follows:

	£ million
project management	27.9
drilling	302.7
pre-operations	20.6
risers	46.4
subsea	211.6
FPSO construction	342.0
FPSO installation	15.1
technical support	9.2
insurance	7.3
UAP contingency	34.4
total	1017.0

8.7 The 2001 "Brown Book" gives the operator's estimate of recoverable reserves originally present at Foinaven as 49.6 million tonnes (approximately 370 mb) and at Schiehallion as 80.0 mt (600 mb). These suggest capital expenditure per tonne of £20.20 for Foinaven (£2.70 per barrel) and £12.70 for Schiehallion (£1.70 per barrel).

8.8 However, Foinaven is being developed in stages and we are not sure if the 49.6 million tonnes reserves are the correct figure to use in such calculations. Phase 2 was completed in 2002 at an estimated cost of £200 million. It included the development of the East Foinaven satellite as a three well subsea tieback to the FPSO. It is expected to add about 4.8 mt (36 mb) to the recoverable reserves.

8.9 The weighted average development cost for Foinaven and Schiehallion is about £15.40 per tonne or £2.05 per barrel. We propose to use those averages for the SEA 4 FPSO fields and a slightly higher average of £20 per tonne or £2.66 per barrel for the subsea fields.

8.10 Applying these averages we get the following estimates of capital expenditure:

	£ million
Pessimistic scenario	
FPSO(1)	300
FPSO(2)	300
SS(1)	45
SS(2)	45
sub-total	690
Optimistic scenario	
FPSO(3)	995
FPSO(4)	995
SS(3)	105
SS(4)	105
sub-total	2200
totals	2890

8.11 The costs of the two smaller FPSO fields are probably underestimated by using these averages but those for the two larger ones are very similar with the actual costs of Foinaven and Schiehallion. Increasing the costs of the pessimistic scenario by 50%, to take account of lower economies of scale and higher unit costs, would add another £345 million of capital expenditure, giving a sub-total of £1035 million.

8.12 We also need to take account of the cost of developing the 50 billion cubic metres of gas in the optimistic scenario. That is even more difficult to estimate because of uncertainties over spare capacity in existing gas pipelines. If we assume an additional cost of £10 million per bcm, there would be additional capital expenditure of about £500 million.

8.13 Thus the total capital expenditure would be approximately:

	£ million
pessimistic scenario	1035
optimistic : oil	2890
optimistic : gas	500
total	4425

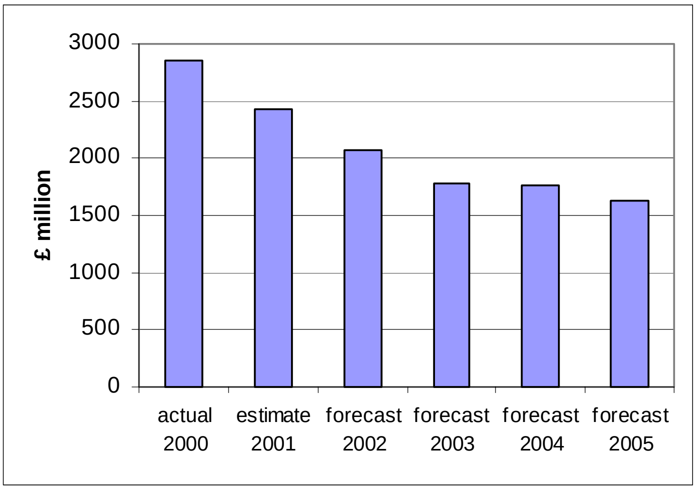
8.14 These totals are based on a number of assumptions but we believe that they are reasonable ones to use in our analysis.

8.15 Table 8.1 and Figure 8.1 set out a suggested time profile for this expenditure which is consistent with our other assumptions. They show the expenditure taking place over a six or seven year period. Under the pessimistic scenario there is a peak of £285 million in 2010 and an annual average of about £170 million. Under the optimistic scenario there is a peak of £885 million (285 + 600) in 2010 and an annual average of about £485 million.

8.16 The capital expenditure would represent important business opportunities for UK suppliers, although there is no guarantee that all the work would go to UK-based businesses. That would obviously depend on their competitiveness at the time.

8.17 In our report on "Prospects for the North Sea Oil and Gas Industry 2002-2005" we gave forecasts of capital expenditure on the UKCS until 2005. They were (in constant 2002 values, with the annual percentage changes in brackets):

actual 2000	£2,848 million	
estimate 2001	£2,422 m	(-15.0%)
forecast 2002	£2,006 m	(-17.2%)
forecast 2003	£1,779 m	(-12.3%)
forecast 2004	£1,754 m	(-11.4%)
forecast 2005	£1,634 m	(-6.8%).

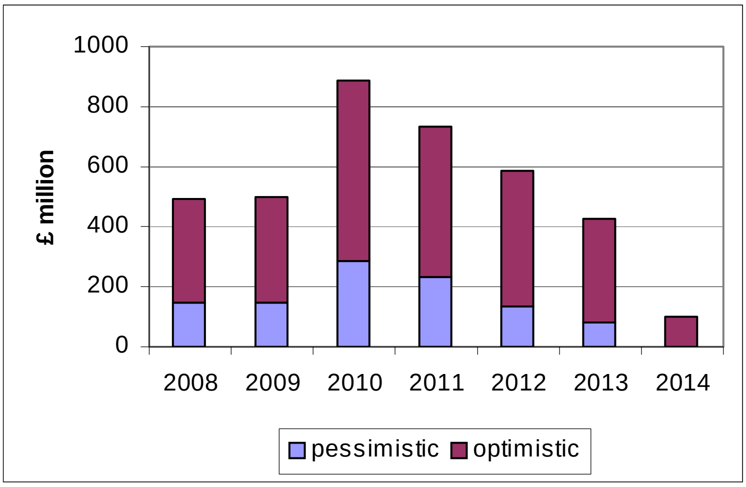


8.18 These forecasts are directly related to the expectation of falling development activity. In 1998 UKCS development expenditure totalled £5.1 billion. There was a massive fall in the next two years as a consequence of the collapse in world oil prices. Unfortunately, that decline seems set to continue and our 2005 forecast is just 32% of the 1998 total.

Table 8.1
SEA 4 capital expenditure scenarios
(£ million)

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Pessimistic									
FPSO(1)		150	150	100	50				
FPSO(2)				150	150	100	50		
SS(1)				35	35				
SS(2)						35	30		
sub total	0	150	150	285	235	135	80		0
Optimistic									
FPSO(3)		345	350	200	100				
FPSO(4)				345	350	200	100		
SS(3)				55	50				
SS(4)						55	50		
gas						200	200	100	
sub-total	0	345	350	600	500	455	350	100	0
total	0	495	500	885	835	590	430	100	0

Figure 8.1
SEA 4 capital expenditure scenarios



8.19 It is difficult to predict future levels of capital expenditure on the UKCS. Table 8.2 assumes that our 2005 forecast is realistic and that expenditure will decline at –5.0% per year from then onwards. The table gives the figures from the pessimistic and optimistic scenarios, and the related percentages of the totals.

Table 8.2
UKCS and SEA 4 capital expenditure forecasts
(£ million, constant 2002 values)

	UKCS	SEA 4 pessimistic	% of UKCS	SEA 4 optimistic	% of UKCS
2005	1634	-	-	-	-
2006	1552	-	-	-	-
2007	1475		-	-	-
2008	1401	150	10.7	495	35.3
2009	1331	150	11.3	500	37.6
2010	1265	285	22.5	885	70.0
2011	1201	235	20.6	835	69.5
2012	1141	135	11.8	590	51.7
2013	1084	80	7.3	430	39.7
2014	1030	-	-	100	9.7
2015	979	-	-	-	-

8.20 With the pessimistic scenario, the SEA 4 expenditure accounts for 22.5% of total UKCS capital expenditure in 2010 and 20.6% in 2011. Over the six year development period the SEA 4 area accounts for an average of 13.9% of the total.

8.21 Even the pessimistic scenario, therefore, would account for a substantial proportion of total capital expenditure during the six year period.

8.22 With the optimistic scenario, the SEA 4 expenditure accounts for a massive 70.0% of the total in 2010 and 69.5% in 2011. Over the seven year period the SEA 4 area accounts for 52.4% - ie more than half – of the total.

8.23 The SEA 4 capital expenditure could be regarded as additional to the (rest of the) UKCS expenditure, rather than as part of it. If so, the optimistic scenario's £4,425 million would be 34.3% of the UKCS total, rather than 52.4%, during the seven years shown.

8.24 Whichever approach is preferred, there can be little doubt that the SEA 4 capital expenditure would be very important during a period when development activity on the rest of the UKCS was declining.

8.25 UK-based suppliers of FPSO and subsea equipment, installation contractors, supply boat and helicopter operators etc would all be very keen to win work for the SEA 4 fields, particularly if their other markets were declining and they had spare capacity. The UK fabrication yards are a good example of that.

Operating expenditure

8.26 Table 8.3 and Figure 8.3 give estimates of annual operating expenditure for the pessimistic and optimistic scenarios.

8.27 The 2001 "Brown Book" includes a chart (2.6, page 21) showing unit operating costs on the UKCS from 1976 to 2000. Average costs generally rose in the period 1976-1990, reaching a peak of about £27 per tonne (£3.60 per barrel) in 1990. The chart shows a fall since then but an increase in 2000 to around £20 per tonne.

8.28 We have assumed the following average costs per tonne of oil produced for the SEA fields (in constant 2003 values):

FPSO (1)	£20
FPSO (2)	£20
FPSO (3)	£15
FPSO (4)	£15
SS (1)	£25
SS (2)	£25
SS (3)	£25
SS (4)	£25

8.29 These costs are reasonably similar with the actual operating costs of Foinaven and Schiehallion, as provided to us by BP, and also the estimates for the Clair field.

8.30 The unit costs for the two larger FPSOs (3) and (4) should be lower than those for the two smaller ones, because of the higher production from (3) and (4). The average costs of the subsea fields should be higher than those of the FPSOs.

8.31 In calculating the estimates, we have assumed that the average unit costs will remain constant over time. In reality, the unit costs are usually the lowest when production is at a peak and then increase slowly as production declines. It would be possible to incorporate such changes in the analysis but we do not believe that is necessary in this study.

8.32 There would also be additional operating costs related to any gas production from the SEA 4 fields but we have not included those in Table 8.3.

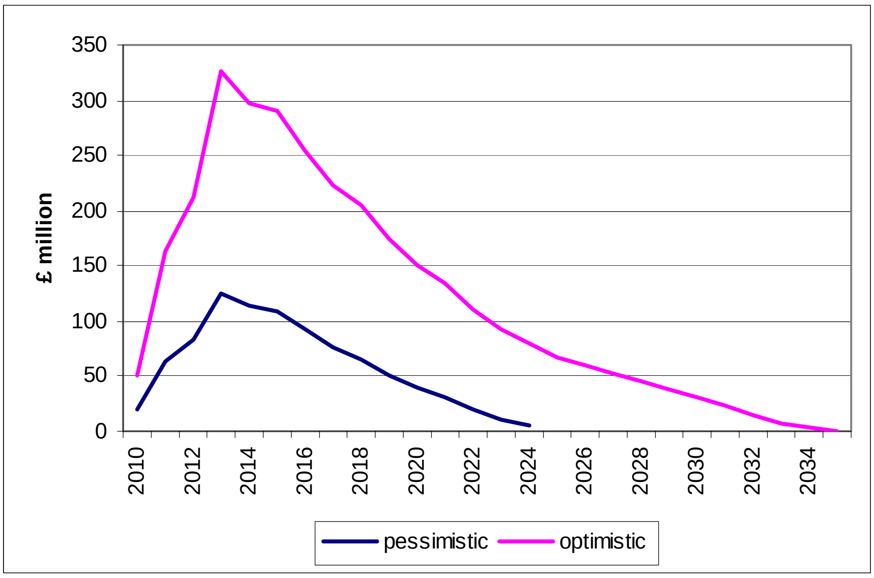
8.33 For the optimistic scenario, the total operating expenditure would be £3108 million, with an annual average of £124.3 million. The peak shown in the table is £326 million in 2013. Operating expenditure would remain above £200 million per year for the next five years (until 2019).

8.34 For the pessimistic scenario, the total operating expenditure would be £899 million, with an annual average of £60.0 million. The peak shown in the table is £126 million in 2013.

Table 8.3
Operating expenditure for the SEA 4 oil fields
(£ million)

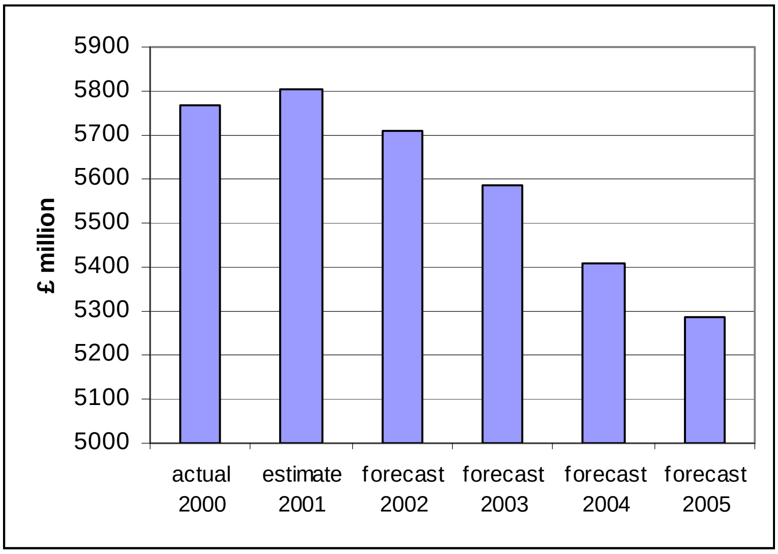
	FPSO (1)	FPSO (2)	SS (1)	SS (2)	Sub total	FPSO (3)	FPSO (4)	SS (3)	SS (4)	Sub total	Total
2010	20				20	30				30	50
2011	50		13		63	75		25		100	163
2012	50	20	13		83	75	30	25		130	213
2013	50	50	13	13	126	75	75	25	25	200	326
2014	45	50	6	13	114	71	75	13	25	184	298
2015	40	50	6	13	109	68	75	13	25	181	290
2016	35	45	6	6	92	64	71	13	13	161	253
2017	30	40		6	76	60	68	6	13	147	223
2018	25	35		6	66	56	64	6	13	139	205
2019	20	30			50	53	60	6	6	125	175
2020	15	25			40	49	56		6	111	151
2021	10	20			30	45	53		6	104	134
2022	5	15			20	41	49				110
2023		10			10	38	45				93
2024		5			5	34	41				80
2025						30	38				68
2026						26	34				60
2027						23	30				53
2028						19	26				45
2029						15	23				38
2030						11	19				30
2031						8	15				23
2032						4	11				15
2033							8				8
2034							4				4
2035											0

Figure 8.3
Operating expenditure for the SEA 4 oil fields



8.35 It is also very difficult to predict operating expenditure for the rest of the UKCS. In our report "Prospects for the North Sea Oil and Gas Industry, 2002-2005" we gave the following estimates and forecasts of operating/production expenditure on the UKCS (in constant 2000 values, with the annual percentage changes in brackets):

actual 2000	£5770 million	
estimate 2001	£5805 m	(+0.6%)
forecast 2002	£5711 m	(-1.6%)
forecast 2003	£5587 m	(-2.2%)
forecast 2004	£5407 m	(-3.2%)
forecast 2005	£5286 m	(-2.2%)



8.36 These forecasts are directly related to the forecasts of oil and gas production, and the numbers of fields in production. However, we have assumed some changes in unit costs.

8.37 Table 8.4 sets out forecasts of UKCS operating expenditure to 2025 on the assumption that our 2005 forecast is accurate and that there is an average annual decline of –3.0% from that year onwards. The SEA forecasts are those in Table 8.3.

Table 8.4
UKCS and SEA 4 operating expenditure forecasts
(£ million, constant 2002 values)

	UKCS	SEA 4 pessimistic	% of UKCS	SEA 4 optimistic	% of UKCS
2005	5286	-	-	-	-
2006	5127	-	-	-	-
2007	4974	-	-	-	-
2008	4824	-	-	-	-
2009	4680	-	-	-	-
2010	4539	20	0.4	50	1.1
2011	4403	63	1.4	163	3.7
2012	4271	83	1.9	213	5.0
2013	4143	126	3.0	326	7.9
2014	4019	114	2.8	298	7.4
2015	3898	109	2.4	290	7.4
2016	3781	92	2.1	253	6.7
2017	3668	76	1.9	223	6.1
2018	3558	66	1.4	205	5.8
2019	3451	50		175	5.1
2020	3347	40		151	4.5
2021	3247	30		134	4.1
2022	3150	20		110	3.5
2023	3055	10		93	3.0
2024	2963	5		80	2.7
2025	2874	-		68	2.4

8.38 At peak (2013) the SEA 4 optimistic scenario would account for an estimated 7.9% of UKCS operating expenditure. That proportion would then decline slowly from 2013 onwards but would remain a significant part of the total spending for the next ten years or so.

8.39 The SEA 4 pessimistic scenario at peak (also 2013) would account for 3.0% of the UKCS total and that proportion would decline from 2013 onwards.

8.40 As with the development expenditure, the SEA 4 expenditure could be included in the UKCS figures or be regarded as additional to it but the conclusions would be just the same.

Exploration expenditure

8.41 There will also be the initial exploration expenditure, which would be relatively small in comparison with the development/capital and production/operating expenditure.

8.42 The DTI scenarios are:

seismic activity

- Area (1) : two 2D seismic surveys and 2-5 3D surveys
- Area (2) : 2-5 2D surveys and 2-5 3D surveys.

exploration wells

- Area (1) : 3-5 wells
- Area (2) : 1-3 wells.

8.43 At an average cost per well of £10 million, the 4-8 wells would cost between £40 million and £80 million. The cost of the seismic activity would be up to £20 million.

Decommissioning expenditure

8.44 Finally, there will be decommissioning expenditure at the end of the productive lives of the various fields. An approximate "rule of thumb" is that this expenditure will be 10% of the original capital costs.

8.45 However, that percentage is probably too high for the SEA 4 fields because the main ones are assumed to use FPSOs, which could be removed and re-used elsewhere. Fields with fixed production platforms – either steel or concrete – are much more expensive to decommission.

8.46 We would not expect the decommissioning expenditure for the SEA 4 fields to exceed £200 million. That would be less than 5% of the original capital costs.

9.0 IMPLICATIONS FOR EXISTING FACILITIES

9.1 The main impacts would come from the development of new fields in the SEA 4 area. The scenarios provided by the DTI were the following for each of the two main areas of interest:

- 1-2 FPSO (floating production, storage, offloading)
- 1-2 subsea systems tied to existing infrastructure
- 8-12 development wells.

9.2 The West of Shetland area has four existing fields – Foinaven, East Foinaven, Schiehallion and Loyal – and a fifth – Clair – currently under development. Foinaven was developed with a FPSO and Schiehallion and Loyal jointly developed with another FPSO. East Foinaven is a satellite of Foinaven.

9.3 Thus the DTI scenarios are similar with existing activity in the area to the west of Shetland. At the time of the development of the above fields, it was concluded that floating systems would be more economic than fixed platforms and pipelines.

9.4 However, the Clair field, which is closer to Shetland, is currently being developed with a fixed platform and a pipeline to the Sullom Voe terminal. The existence of the pipeline could improve the economics of any new discoveries in the SEA 4 area, plus any in the adjacent Faroese waters.

9.5 There is also a gas pipeline now from Foinaven and Schiehallion to the Magnus field in the East Shetland Basin via Sullom Voe. That could also improve the economics of new discoveries by providing a market for any associated gas.

9.6 A critical point is that there is already a well-established infrastructure in the area serving the 29 fields in the East Shetland Basin and 17 fields in the Outer Moray Firth. This infrastructure includes the Sullom Voe terminal in the Shetland Islands, which also handles oil from Schiehallion/Loyal, and the Flotta terminal in the Orkney Islands, which also handles oil from Foinaven.

9.7 Any new discoveries in the SEA 4 area are also very likely to use this existing infrastructure. Thus the socio-economic impacts will be **incremental** or **marginal**, rather than the absolute impacts which would be expected from new discoveries in areas with no existing oil or gas infrastructure. We believe that it is very important to understand the incremental nature of any activity in the SEA 4 area.

9.8 The existing infrastructure is also substantially underutilised at the present time and the utilisation rate is declining in line with falling production from the fields in the East Shetland Basin and the Outer Moray Firth. Thus the general impact of any discoveries in the SEA 4 area would be to slow down the rate of decline.

Sullom Voe oil terminal

9.9 For example, the current throughput design capacity of the Sullom Voe terminal is 1.2 million barrels per day. The current throughput is about 500,000 bpd, which implies an utilisation rate of about 42%. Schiehallion is currently providing about 137,200 bpd or 27% of the throughput.

9.10 Phase 1 of Clair will add about 60,000 bpd from 2004 onwards. That is equivalent to about 12% of the current throughput but the percentage will be higher by the time Clair actually begins production.

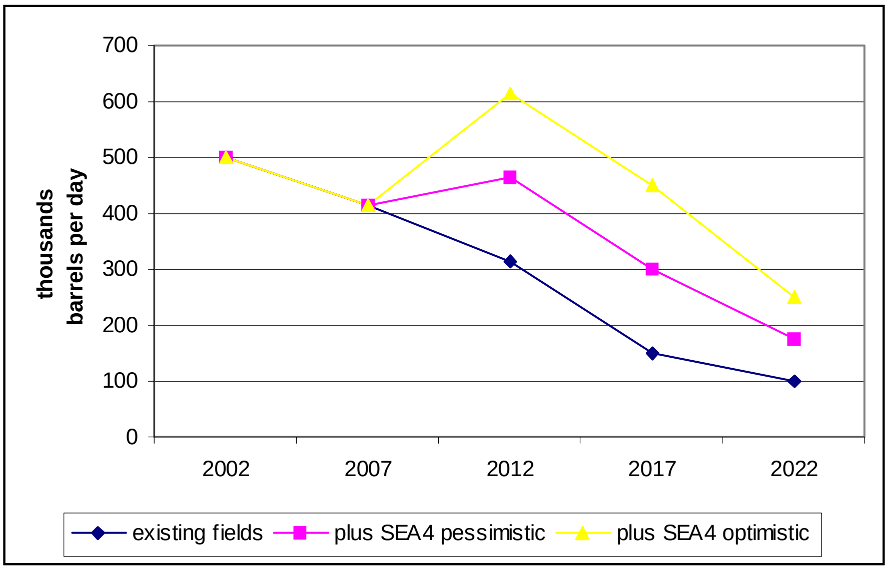
9.11 Table 9.1 sets out three throughput scenarios for the terminal. They are also illustrated in Figure 9.1.

9.12 The first scenario just includes the existing fields. It assumes that output/throughput from the East Shetland Basin will continue to decline at about –10% per year. This output could cease altogether during the 2012-17 period.

Table 9.1
Forecasts of Sullom Voe oil throughput
(thousands of barrels per day)

	2002	2007	2012	2017	2022
East Shetland	350	205	125	-	-
Schiehallion	150	150	90	50	-
Clair	-	60	100	100	100
sub-total	500	415	315	150	100
SEA 4 pessimistic	-	-	150	150	75
sub-total	500	415	465	300	175
SEA 4 optimistic	-	-	150	150	75
total	500	415	615	450	250

Figure 9.1
Forecasts of Sullom Voe oil throughput



9.13 It also assumes that Schiehallion output can be maintained at about 150,000 bpd until 2007 but will then decline at about –10% per year and cease altogether before 2022. Phase 4 of Schiehallion is currently underway with four wells being drilled on what is called Schiehallion North Channel and a fifth on the nearby Craw discovery. There are other discoveries in the area, such as Suilven, Solan and Strathmore, which could be tied back to the Schiehallion FPSO in the future and help to maintain production.

9.14 Phase 1 of Clair is expected to produce 60,000 bpd but there are likely to be further phases and we have assumed that future production can be maintained at 100,000 bpd until 2022. We understand that the Clair pipeline will have capacity to handle 250,000 bpd.

9.15 The scenario for the existing fields shows throughput at Sullom Voe continuing to decline, despite the contribution from Clair, ie

2002	500,000 bpd
2007	415,000 bpd
2012	315,000 bpd
2017	150,000 bpd
2022	100,000 bpd.

9.16 We believe this is a realistic scenario and consistent with the views of BP (the terminal operators) and partners. At some point in the future the terminal's operating costs, as well as those of the Brent and Ninian system pipelines, will rise to a level at which their operation would become unviable, and without new oil that seems likely to be before 2022.

9.17 Table 9.1 and Figure 9.1 show what we have called a pessimistic SEA 4 scenario and an optimistic one. The former assumes 150,000 bpd production from the area in 2012 falling to 75,000 bpd by 2022. That production could come from, say, two new fields – one producing 100,000 bpd through a FPSO and the other 50,000 bpd through a subsea system, or a similar combination of those assumptions.

9.18 The more optimistic combination assumes an additional 150,000 bpd from the SEA 4 area in 2012, also falling to 75,000 bpd by 2017. That could come from two more discoveries.

9.19 Production from the SEA 4 area would, hopefully, begin before 2012. We could produce scenarios with annual throughput forecasts but the key points would still be the same as those in Table 9.1 and Figure 9.1.

9.20 The pessimistic scenario shows a rise in throughput in 2012, or from when the new SEA 4 fields begin production, but a renewal of the decline thenafter. A likely consequence would be to extend the life of the terminal.

9.21 The optimistic scenario shows a much more substantial rise in 2012, with 615,000 bpd exceeding the current throughput, followed by renewed decline. The 2022 throughput would be 250,000 bpd, which should be sufficient to keep the terminal in operation for a few more years.

9.22 Nevertheless the current design capacity of Sullom Voe is 1.2 million barrels per day, which is more than double the current throughput and substantially higher than any of the forecasts in Table 7.1. Thus the main impacts of any SEA 4 discoveries would be

- to slow down the rate of decline

and

- to extend the life of the terminal by a few years.

9.23 It would require very substantial production – say 1 million barrels per day – from the SEA 4 area to have a much more positive impact. That is possible, of course, but very unlikely on present evidence.

9.24 As far as Sullom Voe is concerned it would not matter much if the SEA 4 production arrived by shuttle tanker from a FPSO(s) or via the Clair pipeline or a new pipeline.

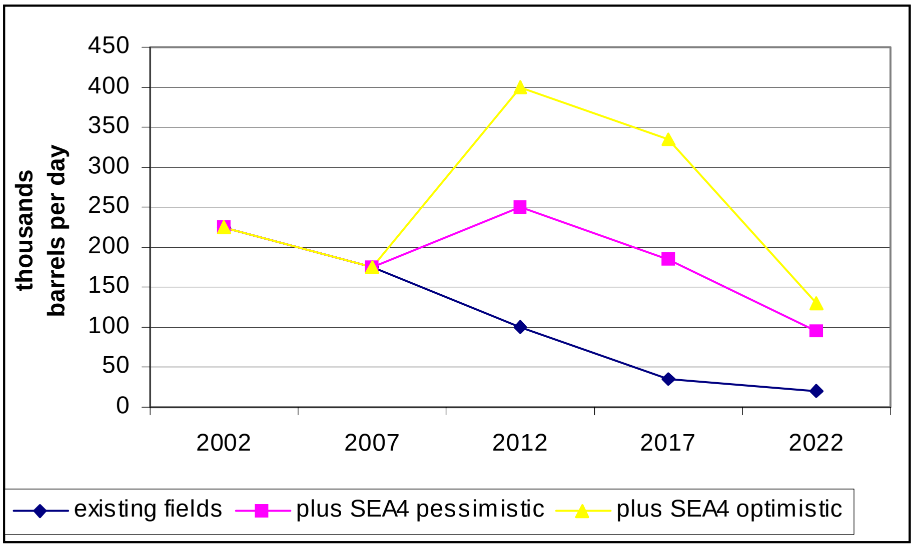
Flotta oil terminal

9.25 Table 9.2 and Figure 9.2 set out similar scenarios for the Flotta oil terminal in the Orkney Islands. The existing throughput is about half of that at Sullom Voe and the general trend is similarly downwards.

Table 9.2
Forecasts of Flotta oil throughput
(thousands of barrels per day)

	2002	2007	2012	2017	2022
Outer Moray Firth	125	75	40	-	-
Foinaven	100	100	60	35	20
sub-total	225	175	100	35	20
SEA 4 pessimistic	-	-	150	150	75
sub-total	-	-	250	185	95
SEA 4 optimistic	-	-	150	150	75
total	225	175	400	335	130

Figure 9.2
Forecasts of Flotta oil throughput



9.26 We have assumed that production from the Outer Moray Firth fields will continue to decline at about –10% per year. On that basis production from this area would cease during the 2012-17 period. We have also assumed that Foinaven output can be maintained at about 100,000 bpd until 2007, possibly with the development of other subsea satellites, but then also decline at –10% per year.

9.27 The SEA 4 pessimistic scenario shows total throughput rising to 250,000 bpd before falling again and the optimistic scenario shows it rising to 400,000 bpd, which is close to the existing capacity at Flotta.

9.28 As with Sullom Voe, therefore, the main impacts of any SEA 4 discoveries would be

- to slow down the rate of decline

and

- to extend the life of the terminal by a few years.

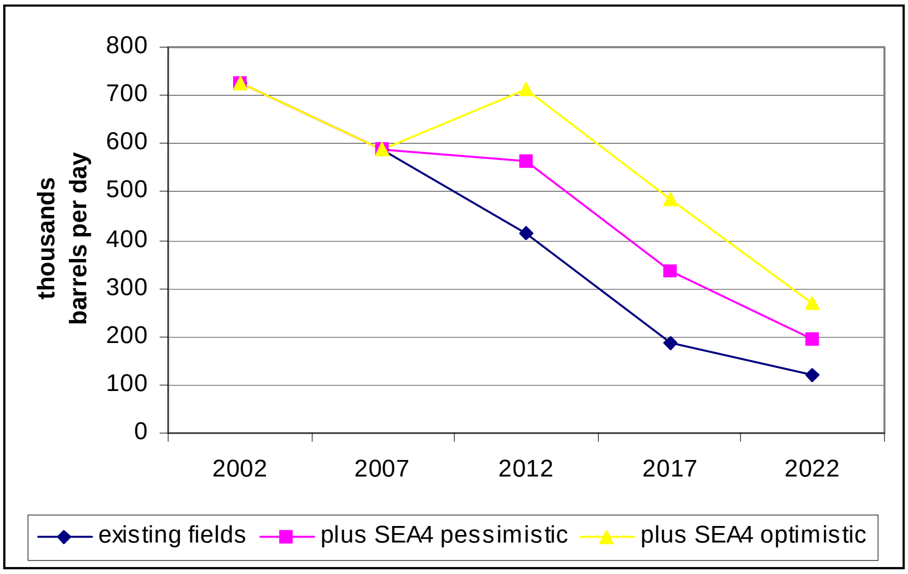
9.29 In actuality some of the SEA 4 production could go to Sullom Voe and some to Flotta, as is the case with Foinaven and Schiehallion, but the overall impacts would be similar with those described above.

9.30 Table 9.3 and Figure 9.3 combine the throughput at Sullom Voe and Flotta, with and without SEA 4 production. The "pessimistic" output figures would account for 26.5% of total throughput in 2012, 44.8% in 2017 and 38.5% in 2022. Including the "optimistic" output, the SEA 4 production would account for 42.0% of total throughput in 2012, 61.9% in 2017 and 55.6% in 2022.

Table 9.3
Combined throughput at Sullom Voe and Flotta
(thousands of barrels per day)

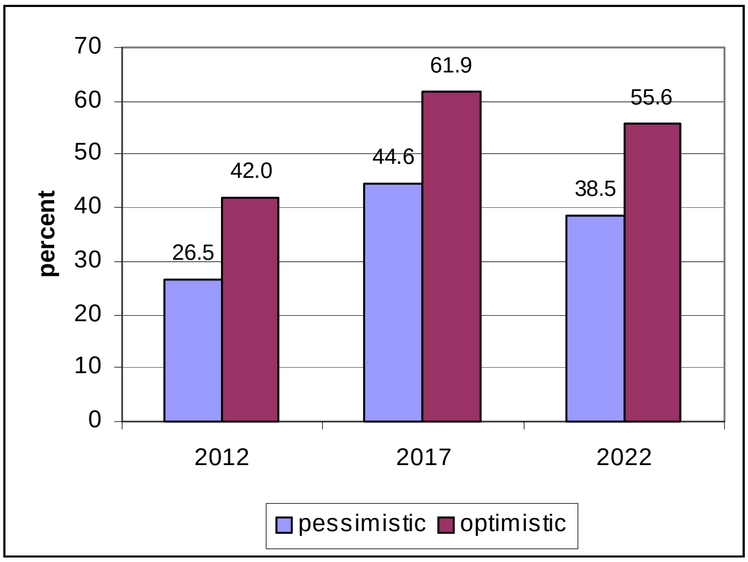
	2002	2007	2012	2017	2022
Sullom Voe	500	415	315	150	100
Flotta	225	175	100	35	20
sub-total	725	590	415	185	120
SEA 4 pessimistic	-	-	150	150	75
sub-total	725	590	565	335	195
SEA 4 optimistic	-	-	150	150	75
total	725	590	715	485	270

Figure 9.3
Combined throughput at Sullom Voe and Flotta



9.31 Thus although any SEA 4 production would be incremental rather than absolute, it could be very important in securing the future of one or both of the terminals and in extending their working lives. The throughput proportions are illustrated in Figure 9.4.

Figure 9.4
SEA 4 contributions to terminal throughput
(percentages)



9.32 In relation to likely employment impacts, current employment at Sullom Voe is currently about 520 (including pilots, tug crews etc) and at Flotta about 310, a total of 830. Applying the throughput proportions calculated above to that total gives the following employment proportions:

	Pessimistic	optimistic
2012	220	349
2017	372	514
2022	315	461

9.33 These are illustrative figures rather than specific forecasts. The employment implications are discussed in detail in Section 10.

Implications for other facilities in Shetland and Orkney

9.34 The implications for other oil-related facilities in Shetland and Orkney are similar. As stressed in Section 4 there is substantial overcapacity among the oil supply base facilities and airport facilities in Shetland. The main reason for that is the general fall in oil-related activity but changes in logistical provision have concentrated services in Aberdeen and Peterhead, at the expense of Shetland.

9.35 Thus there has been a substantial decline in activity at the one remaining supply base in Lerwick, at Sumburgh airport and elsewhere in the islands. These facilities would obviously welcome new business from the SEA 4 area.

Implications for other industries

9.36 Any new development will have impacts on other industries. The development will require inputs, both goods and services, from other businesses, so that their outputs will increase accordingly. If the development competes with existing businesses they may be adversely affected through loss of sales and lower outputs. There can also be external impacts such as pollution and noise.

9.37 Economists often distinguish between

- indirect effects and
- induced effects.

9.38 The indirect or inter-industry effects arise from the purchases of goods and services (inputs) from other industries or businesses. The induced effects arise from the expenditure of people employed by the new development, which will increase trade for local shops etc.

9.39 A common way of calculating these effects is to apply **multipliers** to the direct impacts. These can be calculated by special survey work or by using appropriate multipliers from other studies. There have been many economic impact studies undertaken in Scotland, for both actual and proposed developments, so there is a large volume of data available.

9.40 Of specific relevance to the present study is an input-output study of the Shetland economy undertaken by the Fraser of Allander Institute (FAI) at Strathclyde University. The study report was published in April 1999, although the survey is for the financial year 1996-97. Although the data is therefore a few years out-of-date the report is nevertheless very useful.

9.41 It gives a comprehensive and detailed description of the Shetland economy, including data on the purchases of inputs for every industry and data on the destinations of their outputs (sales). The Sullom Voe oil terminal is classified as a separate industry, as is the oil supply base. The oil terminal having an estimated output of £64,925,510 in the 1996-97 financial year.

9.42 The Sullom Voe terminal accounted for 12.3% of Shetland's gross output in 1996-97 and 9.3% of value added (or net output or GDP). It is worth noting that these proportions are much smaller than those calculated in a similar study for 1987-88. In that year the terminal accounted for 35.9% of gross output and 36.5% of value added (GDP). In the intervening period throughput at the terminal declined substantially.

9.43 The report also gives a breakdown of the terminal's purchases/inputs from other industries in Shetland. The largest of those is £17.4 million from households (in other words, the payment of salaries and wages to the people working at the terminal), followed by £14.9 million for imports, £11.7 million to the distribution industry, £5.0 million to ports and harbours and £2.9 million for business services. The other inputs are relatively small.

9.44 If the output of the terminal increases because of oil production from SEA 4, then expenditure on these inputs should also increase, although not necessarily on a proportionate basis. For example, if we assume that the throughput increases by 10% a starting assumption could be that the payments to households, ports and harbours, distribution and business services could all increase by 10%. However, we noted earlier that employment at the terminal will not increase by 10% because of SEA 4, although the field's oil will help to retain jobs which might otherwise be lost. Nevertheless, increased throughput at the terminal should have beneficial impacts on the other industries listed.

9.45 The 1999 report by the Fraser of Allander Institute includes five "what if" impact simulations. One of those was a 10% reduction in export demand for oil, ie a reduction of 10% in the output of the terminal.

9.46 It shows that a -£6.5 million reduction in output at the terminal would result in a total impact of just under -£14.0 million. That implies a "multiplier" effect of approximately 2.15. The local industries that would be the worst hit are households (-£3.6 million), distribution (-£1.4 million), ports and harbours (-£0.6 million) and business services (-£0.5 million).

9.47 The nature of the input-output model is such that the effects of a +10% increase would be the same as a –10% decrease, but in the opposite direction. Thus if the terminal's output increased by +10%, as we suggest it could with SEA 4, households would benefit by +£3.6 million, distribution by +£1.4 million, ports and harbours by £600,000 etc. These figures are based on the 1996-97 financial year so the current values would be higher.

Possible adverse impacts

9.48 It is possible that the development and operation of any SEA 4 fields will have adverse impacts on other industries, with fishing being the obvious example and tourism another one. Shetland was very badly affected by the Braer oil tanker disaster and local people are understandably concerned about possible oil spills t the Sullom voe terminal or elsewhere.

9.49 The fishing industry has been covered in detail in other SEA 4 reports[1] so we shall only make a few brief comments here. As mentioned earlier, the fishing sector – including fish catching, salmon farming and fish processing – is the single most important part of the Shetland economy. It is also important in Caithness, with Scrabster having become one of the top four fishing ports in Scotland, but less so in Orkney, where there has been more a tradition of farming rather than fishing.

9.50 There is a wide variety of commercial fishing in the SEA 4 area. The main demersal (white) fishing is a mixed fishery targeting cod, haddock and whiting. This has been badly affected recently because of large declines in stocks and consequent large reductions in catch quotas set by the European Commission. There are also deeper water fisheries for species such as halibut, monkfish and saithe.

9.51 Pelagic fishing for herring and mackerel has become much more important recently and has helped to compensate for the decline in white fishing. That is particularly true in Shetland where there is a very large pelagic processing plant (operated by Shetland Catch) in Lerwick.

9.52 Shellfishing is also important in the SEA 4 area, with both mobile and static gear. The target species include nephrops, scallops, crab and lobster.

9.53 Fish farming is also very important economically. The Shetland Islands are one of the main centres for salmon farming in Scotland and there has been recent diversification into cod farming. Other farmed species in the SEA 4 area include mussels, oysters and scallops.

9.54 The main concern of local fishermen and fish farmers is the threat of oil spills, particularly in the light of the Braer disaster. Oil spills could occur at the fields – eg Foinaven and Schiehallion – at the Flotta and Sullom Voe terminals or somewhere in between. The fishermen and fish farmers appear to prefer pipeline transport to tanker loading.

9.55 Foinaven and Schiehallion both use FPSOs and tanker loading, with shuttle tankers taking the oil to the Flotta and Sullom Voe terminals respectively. A gas pipeline was laid recently from Foinaven and Schiehallion to Sullom Voe and from there to the Magnus field in the East Shetland Basin. The laying of an oil pipeline from the Clair field to Sullom Voe is scheduled to begin this summer.

9.56 The same concerns about possible oil spills would obviously apply to any new fields discovered in the SEA 4 area. Our optimistic scenario includes four fields using FPSOs and four using subsea production systems.

[1] Particularly "Fish and Fisheries in the SEA 4 area" by J.D.M. Gordon.

9.57 It is important to remember that the Braer oil tanker had no connection with the local oil industry. Both the Sullom Voe and Flotta terminals, and the pipelines and tankers using them, have excellent records in relation to oil spills and pollution. Nevertheless, the fears of local fishermen and fish farmers are understandable.

9.58 There could also be other negative impacts from oil and gas operations. They include "loss of access" during seismic surveys, exploration drilling and production. However, given the forecast level of activity in the SEA 4 area, we do not believe this is a serious issue.

9.59 When we did the socio-economic impact study of the Clair field for BP, the local fishermen and fish farmers said that they wanted to be consulted about the proposed route of the pipeline from the field to the Sullom Voe terminal. That was also the case with the Magnus EOR gas pipeline. There would inevitably be disruption to fishing during pipelaying. Neither our pessimistic nor optimistic scenarios include a pipeline to Sullom Voe or Flotta but that possibility cannot be completely ruled out.

9.60 Any SEA 4 activity must take full account of these concerns, particularly in the light of the Braer disaster. However, the oil and fishing industries have worked well together in both Shetland and Orkney over the past 25 years and there have been few problems.

9.61 Another industry which could be adversely affected by the oil industry is tourism. That was unfortunately the case with the Braer disaster.

9.62 Tourism is not a major industry in the SEA 4 area but it is nevertheless important and various bodies are endeavouring to increase the number of visitors. Shetland, Orkney and Caithness and Sutherland all have a lot to offer the visitor. Oil spills could have negative impacts.

9.63 We do not believe that other economic activities in the area will be adversely affected by any SEA 4 developments.

10.0 IMPLICATIONS FOR EMPLOYMENT

10.1 The SEA 4 area will generate employment during the

- exploration
- development
- operational/production
- decommissioning

phases. It is sensible to assess these impacts separately in the first instance and then aggregate them.

10.2 In economic impact studies it is common to distinguish between the

- direct
- indirect and
- induced

impacts. We shall concentrate initially on the direct employment impacts and take account of the others later through the application of multipliers.

Exploration

10.3 The licensees will employ people for the duration of their licences, primarily through the operators. Initially their main task will be to assess the geology, decide on the seismic and other surveys and ultimately decide where to drill. The level of employment will obviously depend on the number of licences taken up and the number of firms involved.

10.4 We believe that a reasonable assumption is that there would be an average of about 100 employed in the first few years on SEA 4 work, before declining, as shown in Table 10.1. All the figures are in what could be called “job years”.

10.5 There would then be employment created by the seismic surveys and the exploration drilling. The pessimistic scenario involves four wells and the optimistic scenario eight wells. In Table 10.1 we have assumed that the eight wells will be drilled with two in each of the four years 2007-10. In the pessimistic scenario (Table 10.2) we have assumed one well in each of the four years.

10.6 On the assumption that the average exploration well will take two months and employ about 100 people, the optimistic scenario would generate an annual average of 40 jobs, and the pessimistic scenario 20 jobs. The jobs would only occur during the actual drilling periods, however. In Tables 10.1 and 10.2 we have added 10 and 5 respectively to take account of the seismic and other survey work.

Development

10.7 The development phase will involve the construction of the FPSOs, subsea systems and other equipment required. The pessimistic scenario involves two FPSOs and two subsea systems at an estimated development/capital cost of £690 million, and the optimistic scenario involves two more FPSOs and two more subsea systems, at an additional cost of £2200 million. There is also £500 million for the gas projects, giving a total development cost of £3390 million.

10.8 On the assumption that each £50,000 of development expenditure creates one job (full-time equivalent) for a year, Tables 10.1 and 10.2 set out the development employment estimates. With the optimistic scenario there would be a total 8670 job years, with a peak of 1770 in 2009. With the pessimistic scenario there would be 2070 job years, with a peak of 570 in 2009.

10.9 Our production/operating employment estimates are based on the actual experience of Foinaven and Schiehallion. We have assumed average annual employment of 90 for the smaller FPSO fields and 110 for the larger FPSO fields, and 5 for the smaller subsea fields and 10 for the larger subsea fields.

10.10 Finally, there is the employment which will be generated by the decommissioning work at the end of the lives of the various fields. This will be relatively small scale because of the assumptions of fields using FPSO and subsea systems, rather than fixed production platforms. Fixed platforms are much more difficult and expensive to decommission.

10.11 We have assumed that the decommissioning of the subsea fields will require an average of 5 jobs each in the two years after they cease production, and the FPSO fields an average of 25 jobs each in the two years after they cease production.

10.12 The total employment, year by year, is shown in the tables and also in Figure 10.1. For the optimistic scenario the overall total is 19,830 person years, with a peak of 2555 in 2010. For the pessimistic scenario the overall total is 5440 person years, with a peak of 695 in 2009.

Figure 10.1
SEA 4 employment scenarios
(job years)

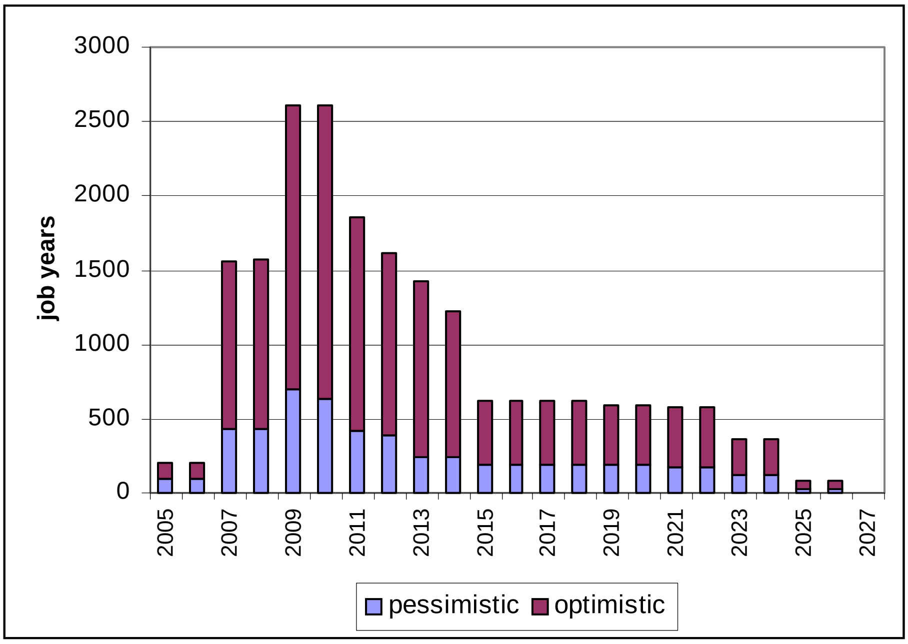


Table 10.1
SEA 4 employment : optimistic scenario

	Licence operations	Exploration	Development	Production	Decommissioning	Total
2005	100	-	-	-	-	100
2006	100	-	-	-	-	100
2007	100	75	1290	-	-	1465
2008	100	75	1300	-	-	1475
2009	100	75	2340	-	-	2515
2010	50	75	2140	290	-	2555
2011	50	-	1450	310	-	1810
2012	50	-	1020	500	-	1570
2013	50	-	700	620	-	1370
2014	50	-	500	620	-	1170
2015	-	-	-	620	-	620
2016	-	-	-	620	-	620
2017	-	-	-	600	15	615
2018	-	-	-	600	15	615
2019	-	-	-	580	15	595
2020	-	-	-	580	15	595
2021	-	-	-	580	-	580
2022	-	-	-	580	-	580
2023	-	-	-	290	75	365
2024	-	-	-	290	75	365
2025	-	-	-	-	75	75
2026	-	-	-	-	75	75
2027	-	-	-	-	-	-

Table 10.2
SEA 4 employment : pessimistic scenario

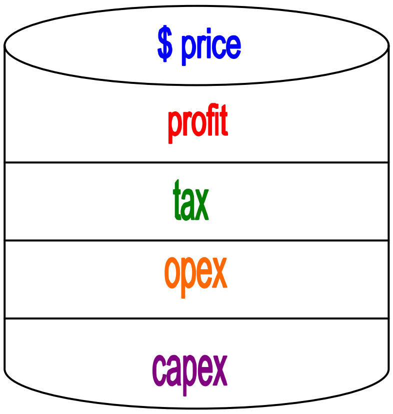
	Licence operations	Exploration	Development	Production	Decommissioning	Total
2005	100	-	-	-	-	100
2006	100	-	-	-	-	100
2007	100	25	300	-	-	425
2008	100	25	300	-	-	425
2009	100	25	570	-	-	695
2010	50	25	470	90	-	635
2011	50	-	270	95	-	415
2012	50	-	160	185	-	395
2013	50	-	-	190	-	240
2014	50	-	-	190	-	240
2015	-	-	-	190	-	190
2016	-	-	-	190	-	190
2017	-	-	-	185	5	190
2018	-	-	-	185	5	190
2019	-	-	-	180	5	185
2020	-	-	-	180	5	185
2021	-	-	-	180	-	180
2022	-	-	-	180	-	180
2023	-	-	-	90	25	115
2024	-	-	-	90	25	115
2025	-	-	-	-	25	25
2026	-	-	-	-	25	25
2027	-	-	-	-	-	-

11.0 IMPLICATIONS FOR TAX REVENUES

11.1 The implications for tax revenues are difficult to estimate because they will depend very much on the level of prices during the lifetimes of the various fields. They have fluctuated considerably in recent years and are likely to do so in the future.

11.2 The diagram below breaks down the price of a barrel of oil into its four key components, namely:

- capital expenditure
- operating expenditure/costs
- tax payments
- profits.



11.3 It would be possible to model each of the SEA 4 fields separately but that would be complicated and we do not believe it is necessary. We believe that the following approach is acceptable for this part of the study.

11.4 Let us assume that the capital and operating costs do not vary with the price of oil – in other words, they are constants. We estimate that the capital cost of the SEA 4 fields over their lifetimes will average $3.10 per barrel (in 2003 values) and the operating cost $2.90, giving a total of $6.00 (approximately £4) per barrel of oil produced. These figures are consistent with estimates provided to us by BP for Foinaven and Schiehallion.

11.5 The UK corporate income tax rate is currently 40%, so the division of the "economic surplus" will be 40% for the Exchequer and 60% for the SEA 4 licensees.

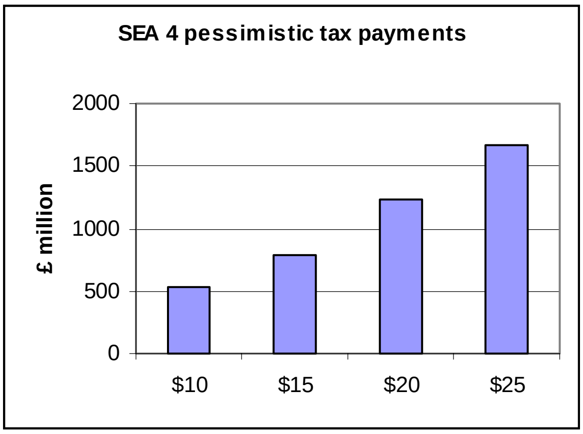
11.6 If the oil price averages $10 per barrel there is then a $4 "surplus" remaining to be divided between the companies and the government. At $10 per barrel the division will be $2.40 and $1.60 respectively.

11.7 If the average oil price rises to $15 per barrel, the surplus actually rises by $5 because the costs remain the same; and similarly at $20, $25 and so on. We have assumed that the tax take will be $1.60 per barrel at $10, $3.60 at $15, $5.60 at $20 and $7.60 at $25 per barrel.

11.8 As set out in Section 6, the pessimistic scenario assumes oil production of 44.0 million tonnes or 330 million barrels. The optimistic scenario assumes oil production of 183.5 million tonnes or 1400 million barrels, plus 50.0 billion cubic metres of gas.

11.9 Using the above assumptions, and an exchange rate of £1 = $1.50, would generate tax revenues of:

- at $10 price $792 million = £528 million
- at $15 price $1188 million = £792 million
- at $20 price $1848 million = £1232 million
- at $25 price $2508 million = £1672 million.

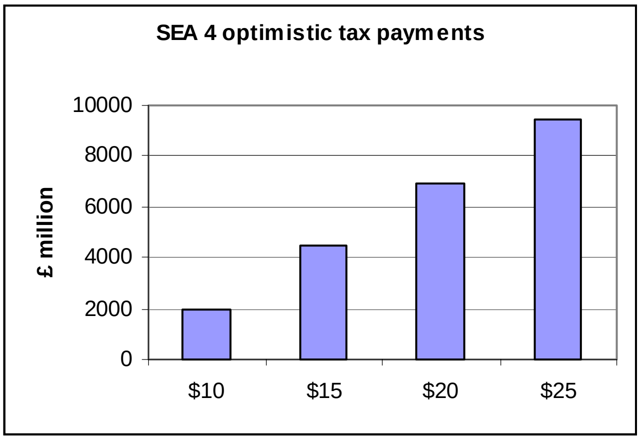


11.10 The optimistic scenario would generate tax payments from the oil production of:

- at $10 price $2240 million = £1493 million
- at $15 price $5040 million = £3360 million
- at $20 price $7840 million = £5227 million
- at $25 price $10,640 million = £7093 million.

11.11 In addition there would be tax payments from the gas production. If we assume that they would be about one third of the above, the totals would rise to:

- at $10 £1990 million
- at $15 £4479 million
- at $20 £6968 million
- at $25 £9455 million



11.12 These estimates are the undiscounted totals over the lifetimes of the SEA 4 fields. They demonstrate the importance of the oil price. The key point to stress is that the tax take increases at a much higher rate than the rise in prices.

11.13 The actual level of prices over the lifetime of the SEA 4 fields will be "anybody's guess" and will undoubtedly fluctuate from year to year. Over the last five years North Sea prices have fluctuated between $9 and $36 per barrel.

11.14 Of the four prices used above the most realistic, on present evidence, is probably an average of $20 per barrel. At that level the SEA 4 fields would generate tax revenues of approximately

(a) pessimistic scenario £1232 million
(b) optimistic scenario £6968 million.

11.15 These figures are undiscounted. If a discount rate of 10% were used, the net present value (NPV) of the pessimistic scenario would be approximately £610 million, with an average annual tax payment of £41 million over fifteen years. The NPV of the optimistic scenario would be approximately £2300 million, with an average annual tax payment of £92 million over 25 years.

11.16 According to the "Brown Book" UK oil and gas production contributed £4825 million in taxes and royalties in the 2000-1 financial year. That was substantially higher than the £2595 million in 1999-2000 and £2514 million in 1998-99.

11.17 The tax revenues will almost certainly decline over the next few years, as a consequence of falling oil and gas production, but it is very difficult to make predictions. If they averaged £1000 million per year when the SEA 4 fields are in production, then the optimistic scenario would account for 9.2% of that total and the pessimistic scenario 4.1%.

12.0 SOCIAL IMPLICATIONS

12.1 As with the economic impacts, the social impacts are likely to be incremental or marginal, rather than absolute. Shetland and Orkney have been involved with the oil industry for over 25 years, and Caithness has also had some involvement with the industry.

12.2 In Section 3 we showed that the population of the SEA 4 area had declined since 1991, with falls in all three of the local authority areas. It is likely that the population will continue to fall over the next decade.

12.3 Thus the main social impact of any SEA 4 developments could be to slow down the rate of population decline and to help retain people in the area. The creation of new jobs or the retention of existing jobs would help to do that, particularly in Shetland and Orkney.

12.4 Declining populations have negative implications for a wide range of social services such as education and health. Many of the settlements in the SEA 4 area are small so the declining populations may imply closures of schools, hospitals and other services. Thus the SEA 4 developments could help to prevent or slow down such closures.

12.5 Given the history of the North Sea oil industry in the area we would not expect any significant problems of social integration. Many of the people working at the Sullom Voe and Flotta terminals, for example, are "incomers" who have settled in the islands. Caithness, through the Dounreay nuclear complex, also has a history of inmigration.

12.6 We do not expect the social implications of developing the SEA 4 area to be substantial but they should be positive, on the whole.

13.0 CONCLUSIONS

13.1 The purpose of this report has been to assess the potential socio-economic implications of licensing the SEA 4 area. This has been done in relation to:

- oil and gas production, and reserves
- capital, operating and decommissioning expenditure
- employment
- tax revenue.

We have also assessed the implications for

- existing facilities.

13.2 The Department of Trade and Industry provided scenarios of possible activity in the area. We converted those into "pessimistic" and "optimistic" scenarios, which have been used in each of the sections.

13.3 The SEA 4 area can be subdivided as follows:

(1) the area of existing and previously licensed acreage;
(2) the northern area which has never been licensed;
(3) the coastal waters close to Shetland and Orkney.

Sub-area (3) is regarded as having very limited hydrocarbon potential so has been ignored in the scenarios.

13.4 There is existing activity, including oil and gas production, from sub-area (1). Four fields are currently in production – Foinaven, East Foinaven, Schiehallion and Loyal – and will be joined by a fifth – Clair – in 2004.

13.5 Also, there is long established production from the East Shetland Basin, which has proved to be one of the most prolific parts of the UKCS, and the Outer Moray Firth area. Most of the oil production from there goes to the Sullom Voe terminal in the Shetland Islands and to the Flotta terminal in the Orkney Islands, both of which were built in the 1970s and have been in operation for about 25 years. There are other oil-related facilities in Shetland and Orkney, which were described in Section 4.

13.6 A key point to stress therefore is that, to a very large extent, the socio-economic impacts of activity in the SEA 4 area will be

- incremental

or marginal (in the economics jargon) rather than absolute. In other words, the impacts will be very different from those which would have occurred if there had been no existing or previous oil and gas-related activity in the area.

13.7 Shetland and Orkney have experienced impacts from activity on the UKCS for about 30 years now and the oil and gas industry is a well-established and important part of the two local economies. Some of the SEA 4 activity will be serviced from Aberdeen or Peterhead on the Scottish mainland and they have also been extensively involved in the industry for many years. The SEA 4 impacts will therefore not be new to these areas and will be on a relatively small scale compared with what has happened in the past.

13.8 A second key point to stress is that existing oil and gas activity in the North of Scotland is declining, as a consequence of falling oil and gas production, and also falling expenditure on the UKCS. The main impacts of SEA 4 activity will be to slow down the declines of the various variables.

13.9 The implications for oil and gas production and reserves were discussed in Section 7. The pessimistic scenario comprises two fields using FPSOs and two smaller fields using subsea systems. The optimistic scenario comprises two more FPSOs and two more subsea systems, all larger than in the pessimistic scenario.

13.10 Under the pessimistic scenario the four fields would produce up to 120,000 barrels of oil per day (bpd) over fifteen years. Total production would be 44.0 million tonnes or 330 million barrels (at 7.5 barrels per tonne).

13.11 Under the optimistic scenario the SEA 4 area would produce an additional 129.0 million tonnes (970 mb) at up to 240,000 bpd. Total production under this scenario would be 173.0 mt (1300 mb), with peak production of 360,000 bpd.

13.12 Forecasts of UKCS oil production were given in Section 7, with the main assumption being an average annual decline of -5.0%. Under the pessimistic scenario SEA 4 production would slow down that decline. For example, 2013 production would be +9.5% higher than otherwise.

13.13 The optimistic SEA 4 scenario gives a significantly different picture, as illustrated in Figure 7.2. Production would actually increase during the five years 2009-13 before the decline resumed. Indeed for the seven years 2009-15 production would be relatively stable at around 80 mt per year (160,000 bpd). In the peak year 2013 total production would be +37.8% higher than it would have been without SEA 4 oil.

13.14 We have also assumed some gas production under the optimistic scenario, from 2010 onwards. At peak it would contribute about 5.7% of the UKCS total.

13.15 Regarding oil reserves, our optimistic scenario of 183.5 million tonnes is 12.3% of the maximum remaining reserves, as stated in the 2001 "Brown Book", and the pessimistic assumption of 44.0 mt is 2.9%. Our assumption of 50 bcm gas in the SEA 4 area is just 3.1% of the maximum remaining reserves and 11.6% of the possible estimate.

13.16 In Section 8 we considered the implications for capital, operating and decommissioning expenditure. The total capital expenditure for the SEA 4 fields would be approximately:

	£ million
pessimistic scenario	1035
optimistic : oil	2890
optimistic : gas	500
total	4425

13.17 We have made some assumptions about future UKCS capital expenditure, With the pessimistic scenario, the SEA 4 expenditure accounts for 22.5% of total UKCS capital expenditure in 2010 and 20.6% in 2011. Over the six year development period the SEA 4 accounts for an average of 13.9% of the total. Even the pessimistic scenario, therefore, would account for a substantial proportion of total capital expenditure during the six year period.

13.18 With the optimistic scenario, the SEA 4 expenditure accounts for a massive 70.0% of the total in 2010 and 69.5% in 2011. Over the seven year period the SEA 4 accounts for 52.4% - ie more than half – of the total.

13.19 At peak (2013) the SEA 4 optimistic scenario would account for an estimated 7.9% of UKCS operating expenditure. That proportion would then decline slowly from 2013 onwards but would remain a significant part of the total spending for the next ten years or so.

13.20 The SEA 4 pessimistic scenario at peak (also 2013) would account for 3.0% of the UKCS total and that proportion would decline from 2013 onwards.

13.21 In Section 9 we discussed the implications for existing facilities. Throughput at the Sullom Voe and Flotta terminals, for example, is declining and there is substantial spare capacity. Any production from the SEA 4 area could slow down this decline and extend the working lives of the terminals. That impact would also apply to many of the other oil-related facilities in the islands, including the airports and supply bases, and – to a lesser extent – those in Aberdeen and Peterhead.

13.22 The implications for employment were considered in Section 10. For the optimistic scenario the overall total is 19,830 person years, with a peak of 1970 in 2010. For the pessimistic scenario the overall total is 5440 person years, with a peak of 695 in 2009.

13.23 The potential implications for tax revenues were considered in Section 11. Of the four prices used the most realistic, on present evidence, is probably an average of $20 per barrel. At that level the SEA 4 fields would generate tax revenues of approximately

(a) pessimistic scenario £1232 million
(b) optimistic scenario £6968 million.

13.24 These figures are undiscounted. If a discount rate of 10% were used, the net present value (NPV) of the pessimistic scenario would be approximately £610 million, with an average annual tax payment of £41 million over fifteen years. The NPV of the optimistic scenario would be approximately £2300 million, with an average annual tax payment of £92 million over 25 years.

13.25 According to the "Brown Book" UK oil and gas production contributed £4825 million in taxes and royalties in the 2000-1 financial year. That was substantially higher than the £2595 million in 1999-2000 and £2514 million in 1998-99.

13.26 The tax revenues will almost certainly decline over the next few years, as a consequence of falling oil and gas production, but it is very difficult to make predictions. If they averaged £1000 million per year when the SEA 4 fields were in production, then the optimistic scenario would account for 9.2% of that total and the pessimistic scenario 4.1%.

13.27 Finally, we made a few comments on social implications in Section 12. The population of the SEA 4 area has declined in recent years and will probably continue to do so. Thus the main social impact of any SEA 4 developments could be to slow down the rate of population decline and help retain education, health and other social services in the area.

13.28 Overall, therefore, the licensing of the SEA 4 area could have a significant impact on the UKCS oil and gas industry. Production from fields in the area could make significant contributions to overall UKCS production, employment and tax revenues, as well as extending the lives of facilities such as the Sullom Voe and Flotta terminals. It could help to retain employment and population in the area.

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