The Potential Socio-Economic Implications of Licensing the SEA2 Area

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1.0 Introduction

1.1 The UK Department of Trade and Industry (DTI) is conducting a sectoral Strategic Environmental Assessment (SEA) of the implications of licensing parts of the North Sea for oil and gas exploration and production. This SEA (SEA 2) is the second in a series planned by the DTI, which will in stages, address the whole of UK waters. As part of the SEA 2 process, a study of the potential socio-economic implications is required. This report fulfils that requirement.

1.2 The whole SEA2 area covers three distinct sub-areas of the UKCS. In the Northern North Sea 60 Blocks or Part Blocks in Quadrants 210, 211, 3, and 9 are open and are potential available for licensing. In the Central North Sea approximately 90 Blocks or Part Blocks in Quadrants 13 to 39 are open. In the Southern North Sea 70 Blocks or Part Blocks are open. The majority of the acreage lies towards the median lines with other North Sea countries.

1.3 The scope of the study includes estimates of the reserves which might be discovered and developed, and the related exploration, appraisal, development and decommissioning costs. The possible phasing of these activities through time is also examined. The effects of the development of new fields in extending the lives of existing ones and the implications for the provision of necessary infrastructure onshore are also examined. The employment generated directly and indirectly in the 3 sub-areas is estimated. The distinction is made between employment at the various stages in the exploration, development and production activities. The significance of the employment opportunities provided for the long-term maintenance of a skilled workforce is also considered.

1.4 In preparing a study of this type many assumptions had to be made. In formulating some of the assumptions regarding the likely numbers and types of new developments, the views of the relevant experts in the DTI were fully taken into account. The number of possible new field developments emanating from the round reflects a cautious view of the possibilities.

2.0 Possible Exploration, Discoveries and Field Developments

2.1 The socio-economic effects of licensing the SEA2 area depend on the exploration, development, and production activities resulting from the new round. There are many underlying uncertainties involved in estimating these effects. The numbers of Blocks nominated and the number subsequently taken up constitute initial uncertainties. It is understood that around 70 Blocks may be on offer in the SNS, 90 in the CNS, and 70 in the NNS. Many of the Blocks on offer will have been relinquished from earlier rounds.

2.2 In the 18th Round the take-up was not very high in relation to the number of Blocks put on offer. This round coincided with a period of very low oil and gas prices which probably influenced the interest shown by the industry. The present price environment is very different though much uncertainty remains.

2.3 The numbers of commitment wells likely to be offered in the new round are also subject to considerable uncertainty. These will reflect both the numbers of Blocks sought and the perceptions of the expected success rates. Exploration success rates, while less than in the 1970's and 1980's, have held up quite well given the maturity of the North Sea acreage in question. One reason for this has been the advances in seismic technology.

2.4 In the present context it is also relevant that much data on previously licensed acreage will be available to new applicants. It is also relevant that in some of the acreage discoveries have already been made. This could enhance the overall success rate, taking into account appraisal as well as exploration.

2.5 It was felt prudent to take a very cautious view of the number of exploration commitment wells. The numbers for the 3 areas and the associated exploration success rates are shown in Table 1.

Table 1

Exploration Commitment Wells and Associated Success Rates			
	SNS	**CNS**	**NNS**
Exploration Commitment Wells	6	10	5
Success Rates	0.25	0.2	0.2

Thus 1.5 (rounded to 2) fields would be found in the SNS, 2 fields would be found in the CNS and 1 field would be found in the NNS.

2.6 With respect to timing of the exploration effort shown in Table 1 it was assumed that, in line with recent Government pronouncements, licensing policy would encourage "early" exploration. Accordingly the timing of the commitment wells was assumed to be as shown in Table 2

Table 2

Timing of Exploration Commitment Wells			
	SNS	**CNS**	**NNS**
2002	3	5	3
2003	2	3	1
2004	1	2	1
Total	**6**	**10**	**5**

2.7 This timing and the exploration success rate determines the timing of the fields found as shown in Table 3.

Table 3

Timing of Discoveries from Exploration Commitment Wells			
	SNS	**CNS**	**NNS**
2002	1	1	1
2003	1	1	0
2004	0	0	0
Total	**2**	**2**	**1**

2.8 These discoveries are then assumed to be appraised with 1 appraisal well per discovery. The timing is shown in Table 4.

Table 4

Timing of Appraisal from New Discoveries			
	SNS	**CNS**	**NNS**
2002			
2003	1	1	1
2004	1	1	
2005			
Total	**2**	**2**	**1**

2.9 The timing of the potential field development relating to these discoveries was taken to be as indicated in Table 5. The time lag between discovery and development is longer in the CNS and NNS compared to the SNS reflecting historic behaviour and the operating environment.

Table 5

Timing of Potential Development of Discoveries			
	SNS	**CNS**	**NNS**
2002			
2003			
2004	1		
2005	1		
2006		1	1
2007		1	

3.0 Size and Costs of New Discoveries

3.1 The size and costs of new discoveries were estimated with the employment of the Monte Carlo technique. With respect to size of discoveries the historical evidence was examined. This indicated that recently the mean field sizes have been 21 mmboe in the SNS, 32 mmboe in the CNS, and 16 mmboe in the NNS. In line with historic experience the distribution of field sizes was taken to be lognormal. The standard deviation (SD) was set at 20% of the mean value.

3.2 With respect to the development and operating costs of new discoveries the mean development cost for the SNS was set at $3 per boe, and for the CNS and NNS $4 per boe. Annual operating costs (including tariffs) were assumed to be in the range 8%-15% of accumulated development costs depending on field size. The lower percentages apply to the larger sizes reflecting the economy of scale. Decommissioning costs were set at 10% of field development costs.

3.3 Employing the above assumptions the Monte Carlo simulations produced the following results:

1. SNS: (a) a 122 Bcf field discovery which would be developed in 2004 with development costs of $3.33/boe, and (b) a 98 Bcf field which would be developed in 2005 with development costs of $2.97/boe.
2. CNS: (a) a 22.8 mmbbl oil field which would be developed in 2006 with development costs of $4.78/bbl, and (b) a 31.8 mmbbl oil field which would be developed in 2007 with development costs of $3.88/bbl.
3. NNS: a 16.2 mmbbl oil field which would be developed in 2006 with development costs of $4.78/bbl.

4.0 Development of Technical Reserves Plus New Discoveries

4.1 The SEA2 area being considered for licensing contains several known discoveries (here described as technical reserves). It is considered likely that some of these will be appraised and possibly developed. From the author's database on technical reserves it was thought that, on a prudent view of prospects, in the SNS 4 of such fields could be appraised and possibly developed, 4 in the CNS, and 3 in the NNS.

4.2 It was considered that in the CNS and NNS all such fields would require appraisal wells, but in the SNS these might not be required. The resultant total numbers of appraisal wells (new finds plus technical reserves) and their timing are shown in Table 6.

Table 6

Timing of all Appraisal Wells Including Technical Reserves			
	SNS	**CNS**	**NNS**
2002		1	
2003	1	1	1
2004	1	1	1
2005		1	
2006	1		
2007			1
2008		1	1
2009	1	1	
2010			

4.3 The new subsequent timing of the potential development of all fields is shown in Table 7.

Table 7

Phasing of Potential New Field Developments			
	SNS	**CNS**	**NNS**
2002			
2003	Technical Reserve	Technical Reserve	
2004	Exploration Find		Technical Reserve
2005	Exploration Find	Technical Reserve	
2006		Exploration Find	Exploration Find
2007	Technical Reserve	Exploration Find	
2008	Technical Reserve		Technical Reserve
2009		Technical Reserve	Technical Reserve
2010	Technical Reserve	Technical Reserve	

4.4 The expenditures on E and A (including associated seismic) are based on costs of £7 million per well in the SNS and £12 million per well in the CNS and NNS. In conjunction with the numbers of wells discussed above the total expenditures (at 2001 prices) are as shown in Table 8.

Table 8

Expenditures on Exploration and Appraisal (£m, 2001 prices)							
	SNS		**CNS**		**NNS**		
	Real Exploration Cost	**Real Appraisal Cost**	**Real Exploration Cost**	**Real Appraisal Cost**	**Real Exploration Cost**	**Real Appraisal Cost**	**Total £m**
2002	21		60	12	36		**129**
2003	14	7	36	12	12	12	**93**
2004	7	7	24	12	12	12	**74**
2005				12			**12**
2006		7					**7**
2007						12	**12**
2008				12		12	**24**
2009		7		12			**19**
Total £m	**42**	**28**	**120**	**72**	**60**	**48**	**370**

4.5 It was necessary to determine which of the technical reserves would most likely be developed. The author’s database of technical reserves revealed a wide range of sizes. It was felt that the larger ones were more likely to be developed. With respect to the SNS fields with reserves of 96 bcf, 168 bcf, 118 bcf, and 78 bcf were chosen. With respect to the CNS fields with reserves of 12 mmbbls, 5 mmbbls, 7 mmbbls, and 21 mmbls were chosen. With respect to the NNS fields of 34 mmbbls and 5 mmbbls were chosen. A gas field of 112 bcf was also chosen for NNS.

4.6 Many of the technical reserves have been discovered a long time ago. It has been assumed that the development cost per boe will be higher than for new exploration finds. The mean development cost for technical reserves in the SNS was set at \$5/boe with a standard deviation of 20% of the mean value. The Monte Carlo simulation runs produced values of \$4.11/boe, \$6.09/boe, \$5.49/boe and \$4.39/boe for the SNS technical reserves fields. The mean development cost for technical reserves in the CNS and NNS was set at \$6/boe with a standard deviation of 20% of the mean value.

The Monte Carlo simulations produced values of $4.8/boe, $5.92/boe, $5.2/boe and $5.37/boe for the CNS technical reserve fields. The Monte Carlo simulation gave values of $4.86/boe, $5.17/boe and $5.53/boe for the NNS technical reserve fields. Operating and decommissioning costs were modelled as for exploration.

5.0 Economic Modelling

5.1 The exploration finds and the technical reserves fields were then profiled through time with respect to production and costs. Economic modelling using the financial simulation technique was then employed to calculate for each development gross revenues, development costs, operating costs, and decommissioning costs. The allowances for corporation tax were calculated and the post-tax cash flows subsequently calculated. Exploration and appraisal costs and the tax reliefs available were also calculated. Production was subject to economic cut-off when post-tax profits for 3 consecutive years were negative. The investment decision rule adopted was that if a field had a positive NPV at 10% real discount rate then development would proceed. Otherwise the field would not be developed. (Further details of the financial modelling are discussed in Kemp and Stephen (2001(a)).

5.2 The results of the economic modelling were undertaken for different oil and gas prices. In the results emphasis was given to the results at (a) $20/bbl and 18 pence/therm and (b) $12 bbl and 12 pence/therm.

6.0 Availability of Offshore Infrastructure

a) SNS

6.1 In the SNS it was felt that there could be 4 developments via sub-sea completions and 2 via platforms. The developments have implications for the field lives of existing potential host installations.

6.2 The SNS is a mature area with a proliferation of infrastructure. In some cases the SEA 2 Blocks or part Blocks in the SNS to be relicensed are close to a number of existing installations, but in other cases they are relatively remote. In Quadrant 42 Blocks 23, 24, 25 and 27(or parts of them) may be relicensed. The Whittle and Wollastone fields lie in Blocks 27 and 28 of Quadrant 42. Block 29 contains Cleeton, and Block 30 contains Ravenspurn. Although Cleeton has ceased production its facilities may continue in use for processing gas for a considerable number of years. Ravenspurn South gas is transported to Dimlington and could continue production until about 2012.

6.3 In Quadrant 43 Blocks 11 to 29 (or parts of them) may be relicensed. Although there are a few not yet developed discoveries in Blocks 11 to 20 the gas fields in these Blocks have been decommissioned. Block 24 contains the Trent gas field. Trent gas is landed at Bacton (Eagles). Block 25 lies between the Trent and Boulton fields. Boulton gas, which could continue production till about 2012, is transported to Murdoch and then through the CMS system to Theddlethorpe. Block 26 contains the Ravenspurn North field. Block 27 contains Johnston. Johnston’s gas is processed on Ravenspurn North and transported with the Ravenspurn gas to Dimlington. Johnston is likely to continue producing until about 2011, whilst Ravenspurn North is likely to continue producing until about 2013. The nearest infrastructure to Block 29 is the Schooner field in Quadrant 44 Block 26. Schooner's gas is also transported to Murdoch. Schooner is likely to continue in production until well after 2020.

6.4 In Quadrant 44 Blocks 11 to 14, 16, 18, 19, 21, 23, 24 and 26 to 29 (or parts of them) may be relicensed. The nearest infrastructure to Blocks 11 to 14 is the Tyne gas field which is likely to continue production until about 2010. Tyne gas is processed on Trent then transported to Bacton (Eagles). The Boulton gas field lies in Quadrant 44 Block 21, Murdoch is in Block 22, Caister is in Block 23, Schooner is in Block 26 and Ketch is in Block 28. Boulton gas is transported to Murdoch then in the CMS system to Theddlethorpe. Murdoch and Caister gas is transported via the CMS system to Theddlethorpe. Murdoch and Caister production is likely to continue until about 2010. Ketch gas is transported to Murdoch. Production is likely to continue till about 2011.

6.5 In Quadrant 47 Blocks 3, 5, 9 and 14 (or parts of them) may be relicensed. Block 3 contains the Rough storage facility 28 kilometres from Easington, Apollo, Artemis and Minerva. Block 4 contains Neptune. The Hyde field, which is in close proximity to West Sole, extends into Block 5. Cleeton and Ravenspurn South lie just north of Blocks 3 and 5. Block 9 contains Mercury. Amethyst and Flowers are in Blocks 14 and 9. Mercury's gas is transported to Neptune then to Cleeton and then onwards to Dimlington. Apollo, Artemis and Minerva will take a similar route. These fields will continue to produce until 2010 to 2017. Hyde's gas is transported to West Sole then on to Easington. Hyde will continue to produce until about 2015. Gas from Amethyst and Flowers is landed at Easington. Flowers will continue to produce until about 2009 whilst Amethyst will continue to produce until about 2017.

6.6 In Quadrant 48 Blocks 1 to 5, 7 to 10, 13, 15, 18 and 21 to 23 (or parts of them) may be relicensed. Blocks 1 and 2 are close to Ravenspurn and Hyde. Block 3 is close to Hoton in Block 7. The nearest infrastructure to Blocks 4 and 5 are Schooner and Ann, but the CMS pipeline goes through the northern part of Block 4. Ann's gas is transported 41 kilometres to the LOGGS riser platform and then on to Theddlethrope. Ann may continue to produce until 2010. West Sole, Newsham and Barque are accessible from Blocks 7 and 8 and Barque, Audrey and Galleon are accessible from Blocks 9 and 10. Newsham gas is transported to West Sole then landed at Easington. Production may continue until 2008. Barque gas will continue to be landed at Bacton until after 2030. Audrey's gas is transported to Valiant North then through the LOGGS system to Theddlethrope. Audrey may produce until 2009. Galleon will continue to produce until after 2030. The gas is transported to Barque. Block 13 is straddled by Barque, Galahad and Mordred and Excalibur and Clipper are near. Galleon, Barque and Audrey are close to or in Block 15. Lancelot, Excalibur, Mordred, Galahad, Barque, Clipper and Anglia are all within easy reach of Block 18. The nearest infrastructures to Blocks 21 and 22 are Waveny, Lancelot and Guinevere, whilst a field in Block 23 would be able to access Lancelot, Anglia, Vulcan or Hewett. Lancelot, Excalibur, Mordred, Galahad, Guinevere, Waveny and Hewett gas are all landed at Bacton whilst Vulcan gas goes through LOGGS to Theddlethrope.

6.7 In Quadrant 49 Blocks 3 to 5, 10, 12, 13, 15 and 25 (or parts of them) may be relicensed. Markham and Windermere lie in Block 5 whilst Chiswick as yet undeveloped, lies in Block 4. Blocks 3, 4 and 5 could also access the Ketch field. Windermere gas is transported to Markham then on to the Netherlands. Block 10 could also access the Markham infrastructure. Block 12 contains North Viking and Block 15 could perhaps access Indefatigable. The Sean gas field lies in Block 25. Viking gas is landed at Theddlethrope. Sean gas is landed at Bacton and Indefatigable gas is transported to Leman and then to Bacton.

6.8 In Quadrant 50 Blocks 16, 21 and 26 (or parts of them) may be relicensed. Blocks 16 and 21 could access Sean. Block 21 could also access Orwell or Brown. Orwell lies in Block 26 and Block 26 could access Davy. Orwell's gas is transported to Thames then Bacton. Brown's gas is transported to Davy and from there to Indefatigable.

6.9 In Quadrant 53 Blocks 1 and 3 to 5 (or parts of them) may be relicensed. Camelot and Cador lie in Block 1 and Blocks 1, 3 and 4 are close to Leman. Davy and Welland are accessible from Block 5.

6.10 In Quadrant 54 only part of Block 1 may be relicensed. Davy and Orwell may be accessed from Block 1.

b) <u>NNS</u>

6.12 Existing infrastructure may be less accessible in the NNS than in the SNS. In Quadrant 210 Blocks 14, 15, 25, 29 and 30 (or parts of them) may be relicensed. The Otter oil field lies in Block 15. Blocks 14 and 15 may access Eider or Magnus. Eider's oil is piped to North Cormorant then on to Sullom Voe, whilst Magnus oil goes through the Ninian system to Sullom Voe. Magnus gas is transported via the FLAGS system to St Fergus. Tern lies in Block 25 and is adjacent to Cormorant. Blocks 29 and 30 could access Hudson, Tern, Heather, Cormorant or Pelican. Oil from Hudson and Pelican is transported via Cormorant and the Brent system to Sullom Voe. Heather's oil production goes through the Ninian system to Sullom Voe whilst the gas goes through FLAGS.

6.12 In Quadrant 211 Blocks 6, 7, 8, 11, 12, 13, 16 to 19, 21 to 24, 26 and 28 (or parts of them) may be relicensed. Block 7 already contains Magnus North West, Block 12 Magnus, Block 13 Penguins, Block 16 Eider, Block 18 Don, Thistle and Devron, Block 19 Playfair an as yet undeveloped field, Block 21 contains Cormorant, Block 23 contains Merlin, Osprey, Dunlin and Skye, Block 26 contains South Cormorant and Pelican, and Block 28 lies between Hutton and Brent.

6.13 In Quadrant 2 Block 10 will be relicensed. This Block contains the Emerald field which has been decommissioned. Heather, Lyell and Columba might be accessible from Block 10.

6.14 In Quadrant 3 Blocks 1, 4 to 14, 16 to 25 and 28 to 30 (or parts of them) may be relicensed. Block 1 lies between Heather and Lyell. Block 4 contains Strathspey . Brent lies above it. Alwyn North lies below it and Ninian lies West of it. The Columba fields lie in Blocks 7 and 8 and part of Ninian and the decommissioned Staffa field also lie in Block 8. Block 9 contains Alwyn North. Block 11 contains

Malory. Block 14 contains Dunbar and Grant with Ellon in the next Block. Blocks 16, 17 and 18 have no infrastructure, but Block 19 contains the Nuggets fields. Blocks 22 to 25 and Blocks 28 to 30 also have no infrastructure, but gas reserves in Blocks 25, 29 and 30 could be tied in to the Frigg system.

c) NNS/CNS Boundary

6.15 In Quadrant 9 Blocks 2, 3, 4, 7 to 13, 16, 17, 21, 24, 26 to 29 (or parts of them) may be relicensed. Bruce, in Block 9, could be accessed from Blocks 2 and 3. Bruce and Frigg could also be accessed from Block 4. Block 7 could access Nevis, Keith in Block 8 or Bruce. Bruce and Frigg could be accessible from Block 10. Block 11 contains Mariner, a yet to be developed field. Ness and Nevis could be accessed from Blocks 11 and 12. Block 13 contains Nevis, Ness Beryl and Katrine. Block 16 might be able to access Buckland or Gryphon in Block 18. Block 17 could access these fields or Harding in Block 23. Block 21 might be able to access Harding as could Blocks 23 and 24. Block 26 is relatively isolated from existing infrastructure except that the SAGE pipeline runs through it. Blocks 27, 28 and 29 could access Crawford, Harding, or East Brae.

d) CNS

6.16 In Quadrant 16 Blocks 1 to 3, 6, 11, 16, 18, 21, 24 and 29 (or parts of them) may be relicensed. Block 1 could access Beinn or Sedgwick in Block 6 whilst Blocks 2 and 3 could also access Brae. Block 11 could access Brae, Larch, Birch or Tiffany. Block 16 could access Tiffany, Toni, Thelma, Bladon in Block 21, Blenheim in Block 21, or Balmoral in Block 21. Block 16 could access Tiffany, Toni or Thelma. Block 24 could access Thelma, Cyrus, Andrew or perhaps Britannia. Block 29 contains the Maureen field which has ceased production. Cyrus, Andrew and Flemming are within transport distance.

6.17 In Quadrant 13 Blocks 17 to 20, 22 and 28 to 30 (or parts of them) may be relicensed. Blocks 17 and 18 could access Captain in Block 22. Blocks 19 and 20 might access Blake in Block 24. Blocks 28 and 29 contain Ross. Cromarty the as yet undeveloped field in Block 30 could access Ross.

6.18 In Quadrant 14 Blocks 12 to 18 and 24 to 30 (or parts of them) may be relicensed. Blocks 12 and 16 are relatively isolated. Blocks 13 and 14 could access Claymore, whilst Block 15 could access Claymore, Highlander or Piper. Blocks 17 and 18 could access Scapa. Blocks 24 and 25 could access Petronella. Block 26 might be able to access Ross. Blocks 27 and 28 are relatively isolated, but, if the as yet undeveloped Ettrick or Goldeneye fields are developed, an export or tie-in route could go through these fields. Blocks 29 and 30 could access Goldeneye or Hanny or Buchan.

6.19 In Quadrant 15 Blocks 12 to 15, 18, 20, 25, 26 and 28 (or parts of them) may be relicensed. Blocks 12 and 13 could access Piper. Block 14 is relatively isolated. Block 15 might be able to access Pine. Block 18 could access Piper, Saltire, Chanter, Galley or MacCulloch. Block 20, which contains the Donan decommissioned, field could access MacCulloch, Bladon or Blenheim. Block 25 could access MacCulloch, Bladon, Blenheim, Balmoral, Glamis or Britannia. Block 26 could access Renee or Buchan. Block 28 could access Renee, Rubie or Britannia.

6.20 In Quadrant 20 Blocks 2 to 4, 7 to 10 and 15 (or parts of them) may be relicensed. Blocks 2 and 3 contain the as yet undeveloped Ettrick field. Block 4 contains the Hannay field and Buchan is near. Blocks 7, 8, and 9 are relatively isolated, but Block 10 could access Buchan. Block 15 is also relatively isolated from any producing field.

6.21 In Quadrant 21 Blocks 1, 3 to 7, 11, 13 to 17, 20, 23 and 28 (or parts of them) may be relicensed. Buchan lies in Block 1. Block 3 could access Rubie or perhaps Britannia. Blocks 4 and 5 could access Britannia and Forties. Block 6 could access Buchan. Block 7 is relatively isolated, although access to Buchan might be possible. Block 11, which contains the decommissioned Dauntless field, could access Kittiwake. Blocks 13 and 14 could access Kittiwake and Forties. Block 15 could access Forties and Nelson. Block 16, which contains the decommissioned Durward field, could access Kittiwake and Block 17 could also access Kittiwake. Block 20 contains the Christian, Cook and Bligh as yet undeveloped fields from which Mallard and Teal are accessible. Block 23 could access Guillemot North West or Teal South. Block 28 contains Dandy and Fyne, as yet undeveloped fields from which Guillemot West and Gannet E are accessible.

6.22 In Quadrant 22 Blocks 1, 2, 5, 6, 8, 11, 12 to 14, 16, 19, 22, 23, 25 and 26 (or parts of them) may be relicensed. Blocks 1 and 2 could access Britannia, Alba, Andrew, Forties, Brimmond and Nelson. Block 5 contains Drake and Everest is near. Block 6 could access Forties, Brimmond or Nelson, parts of which lie in Block 6. Block 8 could access Nelson or Everest. Part of Nelson lies in Block 11. Block 12 could access Nelson, Montrose or Arbroath. Block 13 which contains Watson, an as yet undeveloped field, could access Nelson, Everest and Montrose. Block 14 could access Nelson and Montrose. Block 16 could access Montrose, Arbroath and Gannet D. Block 19 contains Fiddich, an as yet undeveloped field. It could access Montrose, Arbroath, Arkwright, Marnock, Monan and Mungo. Block 22 which contains Selkirk and Millburn, both as yet undeveloped fields, could access Arbroath, Arkwright, Banff, Gannet A, Gannet D and Gannet G. Block 23 contains Arkwright. Marnock and Skua are close by. Block 25 could access Monan, Mungo, Marnock, Skua, Egret, Heron, Machar and Lomond. Block 26 could access Gannet, Banff and Bittern.

6.23 In Quadrant 23 Blocks 6, 11, 16 and 22 (or parts of them) may be relicensed. Block 6 could access Everest. Block 11 could access Everest and Mungo which lies in Block 16. Block 22 contains part of the Pierce field and Lomond is near by.

6.24 In Quadrant 28 Blocks 10, 14, 19 and 20 (or parts of them) may be relicensed. Block 10 could access Bittern and Curlew. Blocks 14, 19 and 20 are relatively remote.

6.25 In Quadrant 29 Blocks 1, 2, 4, 9, 12 to 14, 19, 20 and 23 to 25 (or parts of them) may be relicensed. Block 1 contains Bittern. Block 2 contains Kyle and Banff. Block 4 contains part of Puffin and Franklin and Elgin are accessible. Block 9 contains the as yet undeveloped Beechnut field which might access Curlew as might Blocks 12 and 13. Block 14 is relatively remote as is Block 19. Block 20 could access Auk. Blocks 23 and 24 are relatively remote, but Block 25 could access Auk.

6.26 In Quadrant 30 Blocks 2, 3, 7, 19, 20, 22 to 25 and 27 to 30 (or parts of them) may be relicensed. Blocks 2 and 3 could access Judy which lies in Block 7. Block 19 could access Orion. The closest fields to Block 20 are Innes and Argyll which have both been decommissioned. Block 22 could access Janice, but Blocks 23 and 24 are close only to Innes, Duncan and Argyll all of which have been decommissioned. Block 25 might access Flora. Blocks 27, 28 and 29 are isolated from any producing infrastructure, but Block 30 could access Fife and Flora.

6.27 In Quadrant 31 only part of Block 26 may be relicensed. This Block contains Fife and Flora.

6.28 In Quadrant 38 only Block 5 (or parts of it) may be relicensed. Block 5 could access Fife.

6.29 In Quadrant 39 Blocks 1 and 2 (or parts of them) may be relicensed. Block 1 contains part of Fife and Block 2 contains Fergus.

6.30 The general findings are that there is enormous scope for the further utilisation of the existing infrastructure in all 3 parts of the SEA2 area from the development of new discoveries and technical reserves in blocks being made available in the 20th Round. The precise location of any new discoveries is, of course, not known, and thus the specific offshore infrastructure which might be utilised cannot be specified. Accordingly this has not been modelled.

7.0 Availability of Onshore Infrastructure

7.1 stimate the effects of the resultant new fields on the capacity of the onshore reception facilities full modelling was undertaken.

7.2 The gas production profile for the SNS exploration and technical reserve field developments with an 18p/therm price are shown in Table 9.

<u>Table 9</u>

Prospective Gas Production from the SNS							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Gas (mmcfd)	Gas (mmcfd)	Gas (mmcfd)	Gas (mmcfd)	Gas (mmcfd)	Gas (mmcfd)	**Total**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	10.45	0.00	0.00	0.00	**10.45**
2004	13.26	0.00	43.11	0.00	0.00	0.00	**56.37**
2005	54.70	10.61	43.11	0.00	0.00	0.00	**108.42**
2006	54.70	43.77	41.81	0.00	0.00	0.00	**140.28**
2007	53.04	43.77	36.58	0.00	0.00	0.00	**133.39**
2008	46.41	42.44	28.74	23.05	12.91	0.00	**153.56**
2009	36.47	37.14	23.52	64.55	53.26	0.00	**214.93**
2010	29.84	29.18	18.29	64.55	53.26	10.76	**205.88**
2011	23.21	23.87	15.68	59.94	51.64	38.73	**213.07**
2012	19.89	18.57	0.00	55.33	45.19	38.73	**177.71**
2013	0.00	15.92	0.00	46.11	35.50	32.28	**129.81**
2014	0.00	0.00	0.00	36.89	29.05	27.97	**93.91**
2015	0.00	0.00	0.00	34.58	22.59	21.52	**78.69**
2016	0.00	0.00	0.00	29.97	19.37	17.21	**66.55**
2017	0.00	0.00	0.00	25.36	0.00	15.06	**40.42**
2018	0.00	0.00	0.00	20.75	0.00	12.91	**33.66**
Total BCF	**121.00**	**96.82**	**95.37**	**168.30**	**117.81**	**78.54**	**677.85**

Where this gas would be landed is not clear.

7.3 If <u>all</u> the gas were planned to be landed at Theddlethrope then according to Transco's 10 Year statement (Transco (2000)) the unconstrained capacity at Theddlethrope is sufficient to handle it. However, if capacity were developed in line with Transco's, May 2001 projections capacity could be inadequate for some years, especially under the lower case considered. (For more details on this see Kemp and Stephen (2001a)). If the capacity considered in Transco's July 2001 projections (Transco 2001 (b)) were executed the problem is not so noticeable. (See Kemp and Stephen 2001 (b) for more details).

7.4 At Easington/Dimlington the unconstrained NTS capacity could accommodate the gas. The NTS at Easington/Dimlington has to take peak-demand gas from the Rough field, and capacity problems could possibly emerge for brief periods when production from Rough was at around peak levels. (See Kemp and Stephen 2001 (b)).

7.5 At Bacton there is substantial spare capacity in the NTS in relation to UK production, and, on that basis the extra production could be accommodated. Gas imports from Zeebrugge can also arrive at Bacton and the capacity to import is being substantially increased. Nevertheless the likely Bacton capacity appears to be adequate.

7.6 The gas production profile for the NNS exploration and technical reserve field developments with a $20/bbl and 18p/therm price are shown in Table 10 below.

Table 10

Possible Gas Production from NNS (18p case)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Gas (mmcfd)	Gas (mmcfd)	Gas (mmcfd)	Gas (mmcfd)	**Total**
2002		0.00			**0.00**
2003		0.00			**0.00**
2004		12.30			**12.30**
2005		50.72			**50.72**
2006		50.72			**50.72**
2007		49.18			**49.18**
2008		43.04			**43.04**
2009		33.81			**33.81**
2010		27.67			**27.67**
2011		21.52			**21.52**
2012		18.44			**18.44**
Total BCF		**112.20**			**112.20**

7.7 If St Fergus capacity is as under the Transco 10 Year Statement 2000, then there is not enough capacity at St Fergus even without this extra gas. If St Fergus capacity is as under the Transco "Strong Demand" case (Transco, 2001(a)) then St Fergus could not take this gas until 2005. If capacity is as in Transco's "St Fergus expansion" case (Transco, 2001(a)) then there would be no capacity constraint for this gas being landed at St Fergus. Under the latest Transco projections published in July 2001 (Transco (2001 (b)), reflecting Transco's considered intention after consultation with the industry, there is probably just enough capacity. A new pipeline is currently being laid to reflect the base capacity in Transco's latest planned projections. It is noteworthy that a new import contract from Norway for 1.6 billion cubic metres per year for 15 years has recently been signed. This gas is planned to come to St. Fergus. Further import contracts from Norway may also be expected.

7.8 The oil production profile for the CNS exploration and technical reserve field developments with a $20/bbl and 18p/therm price are shown in Table 11 below.

Table 11

Possible Oil Production from CNS ($20 case)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Oil (tb/d)	Oil (tb/d)	Oil (tb/d)	Oil (tb/d)	Oil (tb/d)	Oil (tb/d)	**Total**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2004	0.00	0.00	3.29	0.00	0.00	0.00	**3.29**
2005	0.00	0.00	5.92	0.68	0.00	0.00	**6.60**
2006	0.00	0.00	5.92	2.60	0.00	0.00	**8.52**
2007	5.01	0.00	5.42	2.47	0.00	0.00	**12.90**
2008	10.77	6.96	3.95	2.33	0.00	0.00	**24.00**
2009	10.77	14.97	3.29	2.19	0.96	0.00	**32.17**
2010	8.76	14.97	2.79	2.05	3.64	0.00	**32.22**
2011	6.88	11.31	2.30	1.37	3.45	4.60	**29.92**
2012	5.38	8.70	0.00	0.00	3.26	10.36	**27.70**
2013	4.38	7.48	0.00	0.00	3.07	10.36	**25.29**
2014	3.76	6.09	0.00	0.00	2.88	8.63	**21.35**
2015	3.76	5.22	0.00	0.00	1.92	6.33	**17.22**
2016	3.13	4.35	0.00	0.00	0.00	5.18	**12.66**
2017	0.00	3.48	0.00	0.00	0.00	4.60	**8.08**
2018	0.00	3.48	0.00	0.00	0.00	4.03	**7.51**
2019	0.00	0.00	0.00	0.00	0.00	3.45	**3.45**
2020	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Total mmbls	**22.85**	**31.76**	**12.00**	**5.00**	**7.00**	**21.00**	**99.61**

There are no onshore infrastructure capacity problems associated with these possible developments.

7.9 The possible oil production profile for the NNS exploration and technical reserve field developments with a $20/bbl and 18p/therm price are shown in Table 12 below.

Table 12

Possible Oil Production from NNS ($20 case)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Oil (tb/d)	Oil (tb/d)	Oil (tb/d)	Oil (tb/d)	**Total**
2002	0.00		0.00	0.00	**0.00**
2003	0.00		0.00	0.00	**0.00**
2004	0.00		0.00	0.00	**0.00**
2005	0.00		0.00	0.00	**0.00**
2006	0.00		0.00	0.00	**0.00**
2007	3.56		0.00	0.00	**3.56**
2008	8.00		0.00	0.00	**8.00**
2009	8.00		7.45	0.68	**16.14**
2010	6.67		16.02	2.60	**25.29**
2011	4.89		16.02	2.47	**23.38**
2012	4.00		12.11	2.33	**18.44**
2013	3.56		8.38	2.19	**14.13**
2014	3.11		6.99	2.05	**12.15**
2015	2.67		6.52	1.37	**10.56**
2016	0.00		5.68	0.00	**5.68**
2017	0.00		4.66	0.00	**4.66**
2018	0.00		3.73	0.00	**3.73**
2019	0.00		2.79	0.00	**2.79**
2020	0.00		2.79	0.00	**2.79**
Total mmbls	**16.23**		**34.00**	**5.00**	**55.23**

There are no onshore infrastructure capacity problems associated with these possible developments

7.10 The gas production profile for the SNS exploration and technical reserve field developments with a 12p/therm price are shown in Table 13 below.

Table 13

Possible Gas Production for SNS (12p case)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 12	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Gas (mmcfd)	Gas (mmcfd)	Gas (mmcfd)	Fails 10%	Fails 10%	Gas (mmcfd)	**Total**
2003	0.00	0.00	10.45			0.00	**10.45**
2004	13.26	0.00	43.11			0.00	**56.37**
2005	54.70	10.61	43.11			0.00	**108.42**
2006	54.70	43.77	41.81			0.00	**140.28**
2007	53.04	43.77	36.58			0.00	**133.39**
2008	46.41	42.44	28.74			0.00	**117.60**
2009	36.47	37.14	23.52			0.00	**97.12**
2010	29.84	29.18	18.29			10.76	**88.07**
2011	23.21	23.87	15.68			38.73	**101.49**
2012	19.89	18.57	0.00			38.73	**77.19**
2013	0.00	15.92	0.00			32.28	**48.19**
2014	0.00	0.00	0.00			27.97	**27.97**
2015	0.00	0.00	0.00			21.52	**21.52**
2016	0.00	0.00	0.00			17.21	**17.21**
2017	0.00	0.00	0.00			15.06	**15.06**
2018	0.00	0.00	0.00			12.91	**12.91**
Total BCF	**121.00**	**96.82**	**95.37**	**0.00**	**0.00**	**78.54**	**391.74**

With respect to the NTS capacity issues at the various terminals the issues which arise are essentially the same as those discussed under the 18 pence case, except that any problems would be less pronounced.

7.11 There is no gas production for the NNS exploration and technical reserve field developments with a $12/bbl and 12p/therm price because the gas field fails the 10% cost of capital hurdle rate.

7.12 The oil production profile for the CNS exploration and technical reserve field developments with a $12/bbl and 12/therm price are shown in Table 14 below.

Table 14

Possible Oil Production in CNS ($12 case)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Oil (tb/d)	Oil (tb/d)	Oil (tb/d)	Fails 10%	Oil (tb/d)	Fails 10%	**Total**
2004	0.00	0.00	3.29		0.00		**3.29**
2005	0.00	0.00	5.92		0.00		**5.92**
2006	0.00	0.00	5.92		0.00		**5.92**
2007	5.01	0.00	5.42		0.00		**10.43**
2008	10.77	6.96	3.95		0.00		**21.67**
2009	10.77	14.97	3.29		0.96		**29.98**
2010	8.76	14.97	2.79		3.64		**30.17**
2011	6.88	11.31	2.30		3.45		**23.95**
2012	5.38	8.70	0.00		3.26		**17.35**
2013	4.38	7.48	0.00		3.07		**14.93**
2014	3.76	6.09	0.00		2.88		**12.72**
2015	3.76	5.22	0.00		1.92		**10.89**
2016	3.13	4.35	0.00		0.00		**7.48**
2017	0.00	3.48	0.00		0.00		**3.48**
2018	0.00	3.48	0.00		0.00		**3.48**
Total mmbls	**22.85**	**31.76**	**12.00**		**7.00**		**73.61**

7.13 The oil production profile for the NNS exploration and technical reserve field developments with a $12/bbl and 12p/therm price are shown in Table 15 below.

Table 15

Possible Oil Production from NNS ($12 case)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Oil (tb/d)	Fails 10%	Fails 10%	Fails 10%	**Total**
2007	3.56				**3.56**
2008	8.00				**8.00**
2009	8.00				**8.00**
2010	6.67				**6.67**
2011	4.89				**4.89**
2012	4.00				**4.00**
2013	3.56				**3.56**
2014	3.11				**3.11**
2015	2.67				**2.67**
Total mmbls	**16.23**				**16.23**

7.14 It is clear from the above calculations that the extra oil and gas production would make a modest contribution to aggregate UK production. There would be no significant shift in the dates at which the UK ceases to be self-sufficient in oil and gas.

8.0 Potential Employment in UK From Licensing of SEA2 Area

8.1 The licensing of the SEA 2 areas will have an impact on the level of employment in the UK. The methodology used to calculate the employment effects broadly follows that used by COGENTSI and PACEC (COGENTSI and PACEC (2001)). Essentially the approach in that report estimates employment from the levels of expenditure using the national input-output tables to estimate all the indirect and induced employment. Direct employment refers to direct employment in exploration, development, production and decommissioning. Indirect employment refers to employment generated by the initial expenditures throughout the supply chain. The input-output tables are used to calculate this employment. Induced employment (or trickle-down employment) refers to the employment generated by the spending of employment income in the direct and indirect categories.

8.2 The study by COGENTSI and PACEC estimated multipliers from which the indirect and induced employment was calculated. The procedure adopted for the present study was to base the calculation on the average multipliers for the period 1999-2001. The multipliers for the direct employment as estimated by COGENTSI and PACEC was modified to reflect the likelihood that, because the great majority of new developments resulting from licensing in the SEA2 area will be with sub-sea systems or not normally manned platforms, the direct employment from the expenditures will be less than the 1999-2001 average.

8.3 The possible total employment generated in the whole SEA2 area under the $20, 18 pence case is shown in Table 16. It is seen to peak at just under 9,000 in 2009 when development activity reaches its peak. The estimates for the SNS under the 18 pence case are shown in Table 17. It is seen that the peak is also in 2009 with 3,756 jobs. The estimates for the CNS under the $20, 18 pence case are shown in Table 18. Peak employment is 2,762 in 2009. The estimates for the NNS are shown in Table 19 under the same price scenario. Peak employment is nearly 2,500 in 2009.

8.4 Total possible employment for the whole SEA2 area under the $12, 12 pence scenario is shown in Table 20. Peak employment is over 4,500 in 2008. There is thus a very substantial oil and gas price sensitivity to the employment prospects. The estimates for the SNS under the 12 pence case are shown in Table 21. Employment peaks in 2006 at just under 1,700. The results for the CNS under the $12, 12 pence scenario are shown in Table 22. Employment peaks at 2,700 in 2009. Employment in the NNS under the same scenario is shown in Table 23. It peaks in 2009 at just under 1,100.

Table 16

Number of Jobs Created from SEA 2

$20/bbl and 18p/therm																				
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Direct																				
Exploration	426	307	244	40	23	40	79	63	0	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	67	220	237	218	310	478	536	379	387	202	102	11	0	31	49	0	80	25	39
Opex	0	6	47	97	118	147	190	260	280	317	281	243	224	211	164	118	115	57	31	0
Total Direct Jobs	**426**	**380**	**512**	**374**	**359**	**497**	**747**	**858**	**659**	**704**	**483**	**344**	**236**	**211**	**196**	**167**	**115**	**138**	**56**	**39**
Indirect jobs (supply chain)																				
Operations	0	16	126	260	315	394	509	695	750	849	753	649	600	565	440	316	308	154	84	0
Development + Decommissioning	0	544	1,789	1,926	1,772	2,522	3,882	4,349	3,078	3,140	1,640	825	92	0	253	398	0	651	201	314
Exploration	1,398	1,008	802	130	76	130	260	206	0	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**1,823**	**1,947**	**3,229**	**2,689**	**2,521**	**3,543**	**5,398**	**6,108**	**4,488**	**4,693**	**2,876**	**1,819**	**928**	**776**	**889**	**881**	**423**	**943**	**341**	**353**
Induced jobs (trickle down)	1,423	1,270	1,711	1,250	1,200	1,663	2,499	2,869	2,205	2,353	1,615	1,151	788	706	654	559	384	460	188	129
Total	**3,247**	**3,217**	**4,940**	**3,939**	**3,721**	**5,206**	**7,897**	**8,977**	**6,693**	**7,046**	**4,491**	**2,969**	**1,716**	**1,481**	**1,542**	**1,440**	**807**	**1,403**	**529**	**482**

Table 17

Number of Jobs created from SEA 2 in SNS																			
$20/bbl and 18p/therm																			
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct																			
Exploration	69	69	46	0	23	0	0	23	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	42	99	102	83	74	189	223	166	149	71	36	11	0	0	25	0	53	0
Opex	0	6	27	51	67	66	82	114	118	127	107	84	66	60	53	33	30	0	0
Total Direct Jobs	**69**	**117**	**172**	**154**	**173**	**140**	**271**	**360**	**284**	**276**	**178**	**120**	**77**	**60**	**53**	**59**	**30**	**53**	**0**
Indirect jobs (supply chain)																			
Operations	0	16	73	137	179	178	220	305	315	339	286	224	175	161	142	90	81	0	0
Development + Decommissioning	0	339	803	832	672	602	1,536	1,811	1,351	1,213	577	291	92	0	0	203	0	431	0
Exploration	228	228	152	0	76	0	0	76	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**297**	**699**	**1,200**	**1,123**	**1,100**	**920**	**2,028**	**2,552**	**1,950**	**1,828**	**1,042**	**635**	**344**	**221**	**195**	**351**	**112**	**484**	**0**
Induced jobs (trickle down)	232	391	577	514	578	470	908	1,204	950	923	595	400	257	201	177	196	102	177	0
Total	**529**	**1,089**	**1,777**	**1,637**	**1,678**	**1,390**	**2,936**	**3,756**	**2,900**	**2,751**	**1,637**	**1,035**	**601**	**421**	**373**	**547**	**214**	**662**	**0**

Table 18

Number of Jobs created from SEA 2 in CNS																			
$20/bbl and 18p/therm																			
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct																			
Exploration	238	158	119	40	0	0	40	40	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	25	63	58	79	149	153	151	111	120	96	45	0	0	8	24	0	27	25
Opex	0	0	12	21	25	42	65	82	89	109	91	96	96	90	77	53	53	26	0
Total Direct Jobs	**238**	**184**	**195**	**118**	**103**	**191**	**257**	**273**	**200**	**229**	**187**	**140**	**96**	**90**	**85**	**77**	**53**	**53**	**25**
Indirect jobs (supply chain)																			
Operations	0	0	33	55	66	113	173	219	239	292	244	257	257	241	205	142	142	70	0
Development + Decommissioning	0	206	515	468	641	1,209	1,244	1,229	901	977	780	362	0	0	65	195	0	220	201
Exploration	780	520	390	130	0	0	130	130	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**1,018**	**910**	**1,133**	**771**	**810**	**1,513**	**1,804**	**1,850**	**1,340**	**1,498**	**1,211**	**759**	**352**	**331**	**354**	**415**	**196**	**343**	**226**
Induced jobs (trickle down)	794	614	651	394	346	639	860	911	669	767	626	470	320	301	283	258	178	178	83
Total	**1,812**	**1,524**	**1,783**	**1,165**	**1,156**	**2,152**	**2,664**	**2,762**	**2,009**	**2,265**	**1,838**	**1,229**	**673**	**632**	**637**	**673**	**373**	**521**	**309**

Table 19

Number of Jobs created from SEA 2 in NNS																			
$20/bbl and 18p/therm																			
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct																			
Exploration	119	79	79	0	0	40	40	0	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	0	58	77	57	88	136	161	102	117	35	21	0	0	23	0	0	0	0
Opex	0	0	7	25	26	39	43	64	73	82	83	63	63	61	35	31	31	31	31
Total Direct Jobs	**119**	**79**	**145**	**102**	**83**	**166**	**219**	**225**	**175**	**198**	**118**	**84**	**63**	**61**	**58**	**31**	**31**	**31**	**31**
Indirect jobs (supply chain)																			
Operations	0	0	20	67	70	104	116	172	196	218	222	169	169	163	93	84	84	84	84
Development + Decommissioning	0	0	472	626	459	711	1,102	1,309	826	949	283	172	0	0	188	0	0	0	0
Exploration	390	260	260	0	0	130	130	0	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**509**	**339**	**896**	**796**	**612**	**1,110**	**1,567**	**1,706**	**1,198**	**1,366**	**623**	**424**	**232**	**224**	**339**	**115**	**115**	**115**	**115**
Induced jobs (trickle down)	397	265	484	342	276	554	731	754	585	664	394	281	211	204	194	105	105	105	105
Total	**906**	**604**	**1,380**	**1,137**	**888**	**1,664**	**2,297**	**2,459**	**1,783**	**2,030**	**1,017**	**706**	**442**	**428**	**533**	**220**	**220**	**220**	**220**

Table 20

Number of Jobs created from SEA 2																			
$12/bbl																			
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct																			
Exploration	426	307	244	40	23	40	79	63	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	67	162	140	173	231	241	192	90	95	61	36	11	0	25	24	0	40	0
Opex	0	6	40	69	85	110	135	149	155	163	130	112	100	93	60	36	34	0	0
Total Direct Jobs	**426**	**380**	**446**	**249**	**281**	**381**	**454**	**404**	**245**	**258**	**191**	**148**	**111**	**93**	**85**	**60**	**34**	**40**	**0**
Indirect jobs (supply chain)																			
Operations	0	16	107	185	227	295	360	399	415	436	347	300	267	248	160	95	92	0	0
Development + Decommissioning	0	544	1,317	1,141	1,406	1,877	1,954	1,561	730	773	497	291	92	0	204	195	0	329	0
Exploration	1,398	1,008	802	130	76	130	260	206	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**1,823**	**1,947**	**2,672**	**1,705**	**1,989**	**2,682**	**3,028**	**2,570**	**1,390**	**1,467**	**1,036**	**740**	**469**	**341**	**448**	**350**	**126**	**369**	**0**
Induced jobs (trickle down)	1,423	1,270	1,492	833	939	1,273	1,519	1,351	819	862	639	495	371	310	284	199	115	135	0
Total	**3,247**	**3,217**	**4,164**	**2,538**	**2,928**	**3,955**	**4,547**	**3,921**	**2,208**	**2,329**	**1,675**	**1,235**	**841**	**651**	**732**	**549**	**240**	**505**	**0**

Table 21

Number of Jobs created from SEA 2 in SNS																			
$12bbl																			
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct																			
Exploration	69	69	46	0	23	0	0	23	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	42	99	102	83	52	35	10	33	47	49	36	11	0	0	0	0	13	0
Opex	0	6	27	51	67	66	62	54	53	59	45	29	16	14	12	11	10	0	0
Total Direct Jobs	**69**	**117**	**172**	**154**	**173**	**119**	**96**	**87**	**86**	**106**	**94**	**65**	**27**	**14**	**12**	**11**	**10**	**13**	**0**
Indirect jobs (supply chain)																			
Operations	0	16	73	137	179	178	165	145	141	158	121	77	43	37	33	31	27	0	0
Development + Decommissioning	0	339	803	832	672	425	281	83	271	380	394	291	92	0	0	0	0	109	0
Exploration	228	228	152	0	76	0	0	76	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**297**	**699**	**1,200**	**1,123**	**1,100**	**721**	**542**	**391**	**498**	**644**	**609**	**433**	**162**	**51**	**45**	**42**	**37**	**122**	**0**
Induced jobs (trickle down)	232	391	577	514	578	397	321	292	287	354	313	216	92	46	41	38	34	45	0
Total	**529**	**1,089**	**1,777**	**1,637**	**1,678**	**1,117**	**863**	**683**	**785**	**997**	**922**	**648**	**254**	**97**	**86**	**80**	**71**	**167**	**0**

Table 22

Number of Jobs created from SEA 2 in CNS

$12/bbl																			
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct																			
Exploration	238	158	119	40	0	0	40	40	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	25	63	38	53	129	153	151	56	48	13	0	0	0	8	24	0	27	0
Opex	0	0	12	18	18	32	55	73	80	84	65	64	64	61	48	24	24	0	0
Total Direct Jobs	**238**	**184**	**195**	**95**	**71**	**162**	**248**	**264**	**137**	**132**	**77**	**64**	**64**	**61**	**56**	**48**	**24**	**27**	**0**
Indirect jobs (supply chain)																			
Operations	0	0	33	48	48	87	147	195	215	224	173	170	170	163	127	65	65	0	0
Development + Decommissioning	0	206	515	309	429	1,050	1,244	1,229	458	393	103	0	0	0	65	195	0	220	0
Exploration	780	520	390	130	0	0	130	130	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**1,018**	**910**	**1,133**	**582**	**547**	**1,299**	**1,768**	**1,818**	**810**	**750**	**354**	**234**	**234**	**224**	**248**	**308**	**89**	**247**	**0**
Induced jobs (trickle down)	794	614	651	319	236	541	828	882	457	442	259	213	213	204	186	161	81	91	0
Total	**1,812**	**1,524**	**1,783**	**901**	**783**	**1,840**	**2,596**	**2,700**	**1,268**	**1,192**	**613**	**446**	**446**	**428**	**433**	**469**	**170**	**338**	**0**

<u>Table 23</u>

Number of Jobs created from SEA 2 in NNS																			
$12/bbl																			
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct																			
Exploration	119	79	79	0	0	40	40	0	0	0	0	0	0	0	0	0	0	0	0
Development + Decommissioning	0	0	0	0	38	49	53	31	0	0	0	0	0	0	17	0	0	0	0
Opex	0	0	0	0	0	11	18	22	22	20	20	20	20	18	0	0	0	0	0
Total Direct Jobs	**119**	**79**	**79**	**0**	**38**	**100**	**111**	**53**	**22**	**20**	**20**	**20**	**20**	**18**	**17**	**0**	**0**	**0**	**0**
Indirect jobs (supply chain)																			
Operations	0	0	0	0	0	30	49	59	59	53	53	53	53	48	0	0	0	0	0
Development + Decommissioning	0	0	0	0	305	402	429	249	0	0	0	0	0	0	139	0	0	0	0
Exploration	390	260	260	0	0	130	130	0	0	0	0	0	0	0	0	0	0	0	0
Total direct and indirect	**509**	**339**	**339**	**0**	**342**	**662**	**719**	**362**	**82**	**73**	**73**	**73**	**73**	**66**	**156**	**0**	**0**	**0**	**0**
Induced jobs (trickle down)	397	265	265	0	125	336	370	177	74	67	67	67	67	60	57	0	0	0	0
Total	**906**	**604**	**604**	**0**	**468**	**998**	**1,089**	**538**	**156**	**140**	**140**	**140**	**140**	**126**	**213**	**0**	**0**	**0**	**0**

9.0 Possible Investment, Operating and Decommissioning Expenditures

9.1 Capital expenditure (excluding drilling) for the SNS field developments with the 18p/therm price are shown in Table 24 below.

Table 24

Possible Capital Expenditure (excl. drilling) in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Capex	Real Capex	Real Capex	Real Capex	Real Capex	Real Capex	**Total £M**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	12.63	0.00	0.00	0.00	**12.63**
2004	13.18	0.00	12.63	0.00	0.00	0.00	**25.82**
2005	13.18	9.41	0.00	0.00	0.00	0.00	**22.59**
2006	0.00	9.41	0.00	0.00	0.00	0.00	**9.41**
2007	0.00	0.00	0.00	6.62	0.00	0.00	**6.62**
2008	0.00	0.00	0.00	17.87	20.86	0.00	**38.73**
2009	0.00	0.00	0.00	17.87	20.86	0.00	**38.73**
2010	0.00	0.00	0.00	17.21	0.00	10.13	**27.33**
2011	0.00	0.00	0.00	6.62	0.00	10.13	**16.74**
2012	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Total £M	**26.36**	**18.82**	**25.27**	**66.19**	**41.72**	**20.25**	**198.61**

9.2 Development drilling expenditures for the SNS exploration and technical reserve field developments with an 18p/therm price are shown in Table 25 below.

Table 25

Possible Development Drilling Expenditures in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Drilling	Real Drilling	Real Drilling	Real Drilling	Real Drilling	Real Drilling	**Total £M**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2004	0.00	0.00	4.13	0.00	0.00	0.00	**4.13**
2005	4.31	0.00	4.13	0.00	0.00	0.00	**8.45**
2006	4.31	3.08	8.27	0.00	0.00	0.00	**15.66**
2007	8.63	3.08	4.13	0.00	0.00	0.00	**15.84**
2008	4.31	6.16	0.00	8.12	0.00	0.00	**18.59**
2009	0.00	3.08	0.00	18.95	6.83	0.00	**28.86**
2010	0.00	0.00	0.00	16.25	6.83	0.00	**23.07**
2011	0.00	0.00	0.00	10.83	13.65	4.05	**28.54**
2012	0.00	0.00	0.00	0.00	6.83	10.13	**16.95**
2013	0.00	0.00	0.00	0.00	0.00	6.08	**6.08**
Total £M	**21.57**	**15.39**	**20.67**	**54.15**	**34.14**	**20.25**	**166.18**

9.3 The results indicate that over the period, total development expenditure at an 18p/ therm price could amount to almost £365 million in real 2001 terms for the SNS.

9.4 Operating expenditures for the SNS fields with an 18p/therm price are shown in Table 26 below.

Table 26

Possible Field Operating Expenditures in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Opex	Real Opex	Real Opex	Real Opex	Real Opex	Real Opex	**Total £M**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	1.78	0.00	0.00	0.00	**1.78**
2004	2.11	0.00	6.19	0.00	0.00	0.00	**8.30**
2005	7.52	1.63	6.40	0.00	0.00	0.00	**15.55**
2006	7.74	5.89	6.67	0.00	0.00	0.00	**20.29**
2007	7.99	6.04	6.07	0.00	0.00	0.00	**20.10**
2008	7.24	6.20	5.21	3.83	2.46	0.00	**24.94**
2009	6.15	5.61	4.64	9.85	8.26	0.00	**34.50**
2010	5.42	4.73	4.07	11.18	8.60	1.68	**35.70**
2011	4.70	4.15	3.58	11.38	9.11	5.46	**38.37**
2012	4.12	3.57	0.00	10.39	8.36	5.96	**32.41**
2013	0.00	3.13	0.00	9.38	7.30	5.56	**25.37**
2014	0.00	0.00	0.00	8.37	6.59	4.89	**19.85**
2015	0.00	0.00	0.00	8.12	5.89	4.18	**18.19**
2016	0.00	0.00	0.00	7.18	5.19	3.71	**16.08**
2017	0.00	0.00	0.00	6.68	0.00	3.47	**10.15**
2018	0.00	0.00	0.00	6.17	0.00	3.05	**9.23**
2019	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2020	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Total £M	**52.99**	**40.96**	**44.61**	**92.53**	**61.76**	**37.96**	**330.81**

9.5 Decommissioning costs for the SNS exploration and technical reserve field developments with an 18p/therm price are shown in Table 27 below.

Table 27

Possible Decommissioning Expenditures in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	**Total £M**
2012	0.00	0.00	4.59	0.00	0.00	0.00	**4.59**
2013	4.79	0.00	0.00	0.00	0.00	0.00	**4.79**
2014	0.00	3.42	0.00	0.00	0.00	0.00	**3.42**
2015	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2016	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2017	0.00	0.00	0.00	0.00	7.59	0.00	**7.59**
2018	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2019	0.00	0.00	0.00	12.03	0.00	4.05	**16.08**
2020	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2021	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Total £M	**4.79**	**3.42**	**4.59**	**12.03**	**7.59**	**4.05**	**36.48**

9.6 Capital expenditure (excluding development drilling) for the CNS field developments with the $20/bbl and 18p/therm price are shown in Table 28 below.

Table 28

Possible Capital Expenditure (excl. drilling) in CNS (£m, 2001)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Capex	Real Capex	Real Capex	Real Capex	Real Capex	Real Capex	**Total £M**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	7.68	0.00	0.00	0.00	**7.68**
2004	0.00	0.00	11.52	0.00	0.00	0.00	**11.52**
2005	0.00	0.00	0.00	5.92	0.00	0.00	**5.92**
2006	16.01	0.00	0.00	3.95	0.00	0.00	**19.96**
2007	8.00	18.09	0.00	0.00	0.00	0.00	**26.09**
2008	16.01	9.04	0.00	0.00	0.00	0.00	**25.05**
2009	0.00	18.09	0.00	0.00	7.28	0.00	**25.36**
2010	0.00	0.00	0.00	0.00	4.85	16.53	**21.38**
2011	0.00	0.00	0.00	0.00	0.00	8.26	**8.26**
2012	0.00	0.00	0.00	0.00	0.00	16.53	**16.53**
Total £M	**40.02**	**45.22**	**19.21**	**9.87**	**12.13**	**41.32**	**167.77**

9.7 Drilling expenditures for the CNS exploration and technical reserve field developments with the $20/bbl and 18p/therm price are shown in Table 29 below.

Table 29

Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Drilling	Real Drilling	Real Drilling	Real Drilling	Real Drilling	Real Drilling	**Total £M**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2004	0.00	0.00	7.68	0.00	0.00	0.00	**7.68**
2005	0.00	0.00	11.52	0.00	0.00	0.00	**11.52**
2006	0.00	0.00	0.00	3.95	0.00	0.00	**3.95**
2007	13.10	0.00	0.00	5.92	0.00	0.00	**19.02**
2008	6.55	14.80	0.00	0.00	0.00	0.00	**21.35**
2009	13.10	7.40	0.00	0.00	0.00	0.00	**20.50**
2010	0.00	7.40	0.00	0.00	4.85	0.00	**12.25**
2011	0.00	7.40	0.00	0.00	7.28	13.52	**28.20**
2012	0.00	0.00	0.00	0.00	0.00	6.76	**6.76**
2013	0.00	0.00	0.00	0.00	0.00	13.52	**13.52**
Total £M	**32.75**	**37.00**	**19.21**	**9.87**	**12.13**	**33.81**	**144.75**

9.8 The results indicate that over the period the total development expenditures with the $20/bbl and 18p/therm price could amount to more than £312 million in real 2001 terms for the CNS.

9.9 Operating expenditures for the CNS field developments with the $20/bbl and 18p/therm price are shown in Table 30 below.

Table 30

Possible Field Operating Expenditures in CNS (£m, 2001)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Opex	Real Opex	Real Opex	Real Opex	Real Opex	Real Opex	**Total £M**
2002	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2004	0.00	0.00	3.76	0.00	0.00	0.00	**3.76**
2005	0.00	0.00	5.38	0.89	0.00	0.00	**6.27**
2006	0.00	0.00	5.38	2.07	0.00	0.00	**7.45**
2007	4.45	0.00	5.38	2.96	0.00	0.00	**12.79**
2008	7.16	4.61	4.84	2.96	0.00	0.00	**19.57**
2009	8.73	7.42	4.84	2.66	1.09	0.00	**24.74**
2010	8.73	8.23	4.84	2.66	2.55	0.00	**27.01**
2011	7.86	9.04	4.84	2.66	3.64	4.98	**33.03**
2012	7.86	8.14	0.00	0.00	3.64	8.01	**27.65**
2013	7.86	8.14	0.00	0.00	3.27	9.77	**29.04**
2014	7.86	8.14	0.00	0.00	3.27	9.77	**29.04**
2015	7.07	8.14	0.00	0.00	3.27	8.79	**27.28**
2016	7.07	7.33	0.00	0.00	0.00	8.79	**23.19**
2017	0.00	7.33	0.00	0.00	0.00	8.79	**16.12**
2018	0.00	7.33	0.00	0.00	0.00	8.79	**16.12**
2019	0.00	0.00	0.00	0.00	0.00	7.91	**7.91**
2020	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Total £M	**74.66**	**83.84**	**39.26**	**16.88**	**20.74**	**75.60**	**310.96**

9.10 Decommissioning costs for the CNS field developments with the $20/bbl price are shown in Table 31 below.

Table 31

Possible Decommissioning Costs in CNS (£m, 2001)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	**Total £M**
2012	0.00	0.00	3.84	1.97	0.00	0.00	**5.81**
2013	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2014	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2015	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2016	0.00	0.00	0.00	0.00	2.43	0.00	**2.43**
2017	7.28	0.00	0.00	0.00	0.00	0.00	**7.28**
2018	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
2019	0.00	8.22	0.00	0.00	0.00	0.00	**8.22**
2020	0.00	0.00	0.00	0.00	0.00	7.51	**7.51**
2021	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Total £M	**7.28**	**8.22**	**3.84**	**1.97**	**2.43**	**7.51**	**31.25**

9.11 Capital expenditures (excluding drilling) for the NNS exploration and technical reserve field developments with the \$20/bbl and 18p/therm price are shown in Table 32 below.

Table 32

Possible Capital Expenditure (excl. Drilling) in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Capex	Real Capex	Real Capex	Real Capex	**Total £M**
2002	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	0.00	0.00	**0.00**
2004	0.00	17.61	0.00	0.00	**17.61**
2005	0.00	17.61	0.00	0.00	**17.61**
2006	11.37	0.00	0.00	0.00	**11.37**
2007	5.69	0.00	0.00	0.00	**5.69**
2008	11.37	0.00	19.34	0.00	**30.71**
2009	0.00	0.00	12.89	5.53	**18.43**
2010	0.00	0.00	12.89	3.69	**16.58**
2011	0.00	0.00	19.34	0.00	**19.34**
2012	0.00	0.00	0.00	0.00	**0.00**
Total £M	**28.43**	**35.21**	**64.47**	**9.22**	**137.33**

9.12 Drilling expenditures for the NNS field developments with the $20/bbl and 18p/therm price are shown in Table 33 below.

Table 33

Possible Development Drilling Expenditures in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Drilling	Real Drilling	Real Drilling	Real Drilling	**Total £M**
2002	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	0.00	0.00	**0.00**
2004	0.00	0.00	0.00	0.00	**0.00**
2005	0.00	5.76	0.00	0.00	**5.76**
2006	0.00	5.76	0.00	0.00	**5.76**
2007	9.31	11.52	0.00	0.00	**20.83**
2008	4.65	5.76	0.00	0.00	**10.41**
2009	9.31	0.00	21.10	0.00	**30.40**
2010	0.00	0.00	10.55	3.69	**14.24**
2011	0.00	0.00	10.55	5.53	**16.08**
2012	0.00	0.00	10.55	0.00	**10.55**
2013	0.00	0.00	0.00	0.00	**0.00**
Total £M	**23.26**	**28.81**	**52.74**	**9.22**	**114.04**

9.13 The results indicate that over the period the total development expenditure with the $20/bbl and 18p/therm price could amount to more than £251 million in real 2001 terms for the NNS.

9.14 Operating expenditures for the NNS exploration and technical reserve field developments with the $20/bbl and 18p/therm price are shown in Table 34 below.

Table 34

Possible Operating Expenditures in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Opex	Real Opex	Real Opex	Real Opex	**Total £M**
2002	0.00	0.00	0.00	0.00	**0.00**
2003	0.00	0.00	0.00	0.00	**0.00**
2004	0.00	2.23	0.00	0.00	**2.23**
2005	0.00	7.60	0.00	0.00	**7.60**
2006	0.00	7.89	0.00	0.00	**7.89**
2007	3.43	8.30	0.00	0.00	**11.73**
2008	5.51	7.59	0.00	0.00	**13.10**
2009	6.72	6.58	5.33	0.83	**19.47**
2010	6.72	5.91	7.68	1.94	**22.24**
2011	6.05	5.24	10.67	2.77	**24.72**
2012	6.05	4.61	11.72	2.77	**25.15**
2013	6.05	0.00	10.55	2.49	**19.09**
2014	6.05	0.00	10.55	2.49	**19.09**
2015	5.44	0.00	10.55	2.49	**18.48**
2016	0.00	0.00	10.55	0.00	**10.55**
2017	0.00	0.00	9.49	0.00	**9.49**
2018	0.00	0.00	9.49	0.00	**9.49**
2019	0.00	0.00	9.49	0.00	**9.49**
2020	0.00	0.00	9.49	0.00	**9.49**
Total £M	**52.02**	**55.96**	**115.57**	**15.77**	**239.31**

9.15 Decommissioning costs for the NNS field developments with the \$20/bbl and 18p/therm price are shown in Table 35 below.

Table 35

Possible Decommissioning Costs in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	**Total £M**
2012	0.00	0.00	0.00	0.00	**0.00**
2013	0.00	6.40	0.00	0.00	**6.40**
2014	0.00	0.00	0.00	0.00	**0.00**
2015	0.00	0.00	0.00	0.00	**0.00**
2016	5.17	0.00	0.00	1.84	**7.01**
2017	0.00	0.00	0.00	0.00	**0.00**
2018	0.00	0.00	0.00	0.00	**0.00**
2019	0.00	0.00	0.00	0.00	**0.00**
2020	0.00	0.00	0.00	0.00	**0.00**
2021	0.00	0.00	11.72	0.00	**11.72**
Total £M	**5.17**	**6.40**	**11.72**	**1.84**	**25.14**

9.16 Capital expenditures (excluding drilling) for the SNS field developments with a 12p/therm are shown in Table 36 below.

Table 36

Possible Capital Expenditure (excl. Drilling) in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Capex	Real Capex	Real Capex	Fails 10%	Fails 10%	Real Capex	**Total £M**
2002	0.00	0.00	0.00			0.00	**0.00**
2003	0.00	0.00	12.63			0.00	**12.63**
2004	13.18	0.00	12.63			0.00	**25.82**
2005	13.18	9.41	0.00			0.00	**22.59**
2006	0.00	9.41	0.00			0.00	**9.41**
2007	0.00	0.00	0.00			0.00	**0.00**
2008	0.00	0.00	0.00			0.00	**0.00**
2009	0.00	0.00	0.00			0.00	**0.00**
2010	0.00	0.00	0.00			10.13	**10.13**
2011	0.00	0.00	0.00			10.13	**10.13**
2012							**0.00**
Total £M	**26.36**	**18.82**	**25.27**			**20.25**	**90.70**

9.17 Drilling expenditures for the SNS field developments with a 12p/therm price are shown in Table 37 below.

Table 37

Possible Drilling Expenditures in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Drilling	Real Drilling	Real Drilling	Fails 10%	Fails 10%	Real Drilling	**Total £M**
2002	0.00	0.00	0.00			0.00	**0.00**
2003	0.00	0.00	0.00			0.00	**0.00**
2004	0.00	0.00	4.13			0.00	**4.13**
2005	4.31	0.00	4.13			0.00	**8.45**
2006	4.31	3.08	8.27			0.00	**15.66**
2007	8.63	3.08	4.13			0.00	**15.84**
2008	4.31	6.16	0.00			0.00	**10.47**
2009	0.00	3.08	0.00			0.00	**3.08**
2010	0.00	0.00	0.00			0.00	**0.00**
2011	0.00	0.00	0.00			4.05	**4.05**
2012	0.00	0.00	0.00			10.13	**10.13**
2013	0.00	0.00	0.00			6.08	**6.08**
Total £M	**21.57**	**15.39**	**20.67**			**20.25**	**77.89**

9.18 The results indicate that over the period the total development expenditure at a 12p/therm price could amount to more than £168 million in real 2001 terms for the SNS compared to £365 million at the 18 pence price.

9.19 Operating expenditures for the SNS field developments with a 12p/therm price are shown in Table 38 below.

Table 38

Possible Operating Expenditures in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Opex	Real Opex	Real Opex	Fails 10%	Fails 10%	Real Opex	**Total £M**
2002	0.00	0.00	0.00			0.00	**0.00**
2003	0.00	0.00	1.78			0.00	**1.78**
2004	2.11	0.00	6.19			0.00	**8.30**
2005	7.52	1.63	6.40			0.00	**15.55**
2006	7.74	5.89	6.67			0.00	**20.29**
2007	7.99	6.04	6.07			0.00	**20.10**
2008	7.24	6.20	5.21			0.00	**18.66**
2009	6.15	5.61	4.64			0.00	**16.40**
2010	5.42	4.73	4.07			1.68	**15.91**
2011	4.70	4.15	3.58			5.46	**17.89**
2012	4.12	3.57	0.00			5.96	**13.65**
2013	0.00	3.13	0.00			5.56	**8.69**
2014	0.00	0.00	0.00			4.89	**4.89**
2015	0.00	0.00	0.00			4.18	**4.18**
2016	0.00	0.00	0.00			3.71	**3.71**
2017	0.00	0.00	0.00			3.47	**3.47**
2018	0.00	0.00	0.00			3.05	**3.05**
Total £M	**52.99**	**40.96**	**44.61**			**37.96**	**176.52**

9.20 Decommissioning costs for the SNS exploration and technical reserve field developments with a 12p/therm price are shown in Table 39 below.

Table 39

Possible Decommissioning Costs in SNS (£m, 2001)							
Field Type	Gas	Gas	Gas	Gas	Gas	Gas	
Field Name	Exploration Find 1	Exploration Find 2	Technical Reserve 1	Technical Reserve 2	Technical Reserve 3	Technical Reserve 4	
Area	SNS	SNS	SNS	SNS	SNS	SNS	
	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Fails 10%	Fails 10%	Real Decommissioning Cost	**Total £M**
2012	0.00	0.00	4.59			0.00	**4.59**
2013	4.79	0.00	0.00			0.00	**4.79**
2014	0.00	3.42	0.00			0.00	**3.42**
2015	0.00	0.00	0.00			0.00	**0.00**
2016	0.00	0.00	0.00			0.00	**0.00**
2017	0.00	0.00	0.00			0.00	**0.00**
2018	0.00	0.00	0.00			0.00	**0.00**
2019	0.00	0.00	0.00			4.05	**4.05**
Total £M	**4.79**	**3.42**	**4.59**			**4.05**	**16.86**

9.21 Capital expenditures (excluding drilling) for the CNS field developments with a \$12/bbl and 12p/therm price are shown in Table 40 below.

Table 40

Possible Capital Expenditure (excl. Drilling) in CNS (£m, 2001)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Capex	Real Capex	Real Capex	Fails 10%	Real Capex	Fails 10%	**Total £M**
2002	0.00	0.00	0.00		0.00		**0.00**
2003	0.00	0.00	7.68		0.00		**7.68**
2004	0.00	0.00	11.52		0.00		**11.52**
2005	0.00	0.00	0.00		0.00		**0.00**
2006	16.01	0.00	0.00		0.00		**16.01**
2007	8.00	18.09	0.00		0.00		**26.09**
2008	16.01	9.04	0.00		0.00		**25.05**
2009	0.00	18.09	0.00		7.28		**25.36**
2010	0.00	0.00	0.00		4.85		**4.85**
Total £M	**40.02**	**45.22**	**19.21**		**12.13**		**116.58**

9.22 Drilling expenditures for the CNS field developments with a $12/bbl and 12p/therm price are shown in Table 41 below.

Table 41

Possible Drilling Expenditure in CNS (£m, 2001)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Drilling	Real Drilling	Real Drilling	Fails 10%	Real Drilling	Fails 10%	**Total £M**
2002	0.00	0.00	0.00		0.00		**0.00**
2003	0.00	0.00	0.00		0.00		**0.00**
2004	0.00	0.00	7.68		0.00		**7.68**
2005	0.00	0.00	11.52		0.00		**11.52**
2006	0.00	0.00	0.00		0.00		**0.00**
2007	13.10	0.00	0.00		0.00		**13.10**
2008	6.55	14.80	0.00		0.00		**21.35**
2009	13.10	7.40	0.00		0.00		**20.50**
2010	0.00	7.40	0.00		4.85		**12.25**
2011	0.00	7.40	0.00		7.28		**14.68**
Total £M	**32.75**	**37.00**	**19.21**		**12.13**		**101.08**

9.23 The results indicate that over the period the total development expenditure with a $12/bbl and 12p/therm price could amount to more than £217 million in real 2001 terms for the CNS compared to £312 million at the higher prices.

9.24 Operating expenditures for the CNS field developments with a $12/bbl and 12p/therm price are shown in Table 42 below.

Table 42

Possible Operating Expenditures in CNS (£m, 2001)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Opex	Real Opex	Real Opex	Fails 10%	Real Opex	Fails 10%	**Total £M**
2002	0.00	0.00	0.00		0.00		**0.00**
2003	0.00	0.00	0.00		0.00		**0.00**
2004	0.00	0.00	3.76		0.00		**3.76**
2005	0.00	0.00	5.38		0.00		**5.38**
2006	0.00	0.00	5.38		0.00		**5.38**
2007	4.45	0.00	5.38		0.00		**9.83**
2008	7.16	4.61	4.84		0.00		**16.61**
2009	8.73	7.42	4.84		1.09		**22.08**
2010	8.73	8.23	4.84		2.55		**24.35**
2011	7.86	9.04	4.84		3.64		**25.38**
2012	7.86	8.14	0.00		3.64		**19.64**
2013	7.86	8.14	0.00		3.27		**19.27**
2014	7.86	8.14	0.00		3.27		**19.27**
2015	7.07	8.14	0.00		3.27		**18.49**
2016	7.07	7.33	0.00		0.00		**14.40**
2017	0.00	7.33	0.00		0.00		**7.33**
2018	0.00	7.33	0.00		0.00		**7.33**
Total £M	**74.66**	**83.84**	**39.26**		**20.74**		**218.49**

9.25 Decommissioning costs for the CNS exploration and technical reserve field developments with a $12/bbl and 12p/therm price are shown in Table 43 below.

Table 43

Possbile Decommissioning Costs in CNS (£m, 2001)							
Field Type	Oil	Oil	Oil	Oil	Oil	Oil	
Field Name	Exploration Find 3	Exploration Find 4	Technical Reserve 5	Technical Reserve 6	Technical Reserve 7	Technical Reserve 8	
Area	CNS	CNS	CNS	CNS	CNS	CNS	
	Real Decommissioning Cost	Real Decommissioning Cost	Real Decommissioning Cost	Fails 10%	Real Decommissioning Cost	Fails 10%	**Total £M**
2012	0.00	0.00	3.84		0.00		**3.84**
2013	0.00	0.00	0.00		0.00		**0.00**
2014	0.00	0.00	0.00		0.00		**0.00**
2015	0.00	0.00	0.00		0.00		**0.00**
2016	0.00	0.00	0.00		2.43		**2.43**
2017	7.28	0.00	0.00		0.00		**7.28**
2018	0.00	0.00	0.00		0.00		**0.00**
2019	0.00	8.22	0.00		0.00		**8.22**
Total £M	**7.28**	**8.22**	**3.84**		**2.43**		**21.77**

9.26 Capital expenditures (excluding drilling) field developments with a \$12/bbl and 12p/therm price are shown in Table 44 below.

Table 44

Possible Capital Expenditure in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Capex	Fails 10%	Fails 10%	Fails 10%	**Total £M**
2002	0.00				**0.00**
2003	0.00				**0.00**
2004	0.00				**0.00**
2005	0.00				**0.00**
2006	11.37				**11.37**
2007	5.69				**5.69**
2008	11.37				**11.37**
Total £M	**28.43**				**28.43**

9.27 Drilling expenditures for the NNS field developments with a $12/bbl and 12p/therm price are shown in Table 45 below.

Table 45

Possible Development Drilling Expenditures in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Drilling	Fails 10%	Fails 10%	Fails 10%	**Total £M**
2002	0.00				**0.00**
2003	0.00				**0.00**
2004	0.00				**0.00**
2005	0.00				**0.00**
2006	0.00				**0.00**
2007	9.31				**9.31**
2008	4.65				**4.65**
2009	9.31				**9.31**
Total £M	**23.26**				**23.26**

With only 1 field passing the 10% hurdle rate, the total development expenditure with a $12/bbl and 12p/therm price could amount to less than £52 million in real 2001 terms for the NNS compared to £251 million at the higher prices.

9.28 Operating expenditures for the NNS field developments with a $12/bbl and 12p/therm price are shown in Table 46 below.

Table 46

Possible Operating Expenditures in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Opex	Fails 10%	Fails 10%	Fails 10%	**Total £M**
2002	0.00				**0.00**
2003	0.00				**0.00**
2004	0.00				**0.00**
2005	0.00				**0.00**
2006	0.00				**0.00**
2007	3.43				**3.43**
2008	5.51				**5.51**
2009	6.72				**6.72**
2010	6.72				**6.72**
2011	6.05				**6.05**
2012	6.05				**6.05**
2013	6.05				**6.05**
2014	6.05				**6.05**
2015	5.44				**5.44**
Total £M	**52.02**				**52.02**

9.29 Decommissioning costs for the NNS field developments with a $12/bbl and 12p/therm price are shown in Table 47 below.

Table 47

Possible Decommissioning Costs in NNS (£m, 2001)					
Field Type	Oil	Gas	Oil	Oil	
Field Name	Exploration Find 5	Technical Reserve 9	Technical Reserve 10	Technical Reserve 11	
Area	NNS	NNS	NNS	NNS	
	Real Decommissioning Cost	Fails 10%	Fails 10%	Fails 10%	**Total £M**
2012	0.00				**0.00**
2013	0.00				**0.00**
2014	0.00				**0.00**
2015	0.00				**0.00**
2016	5.17				**5.17**
Total £M	**5.17**				**5.17**

10.0 Potential Tax Revenues

10.1 The potential tax take from the exploration, development and production activities was calculated under the existing tax arrangements. The expenditure figures are those discussed above. Thus the tax take takes no account of deductions for loan interest, overheads, and R and D expenditures. Accordingly, the tax revenue figures will be overstated.

10.2 Table 48 below shows the tax revenue from production under the \$20/bbl and 18p/therm case.

Table 48

Tax Take from Projected SEA2 Activity (£m, 2001)				
Real 2001	**SNS Tax Revenue**	**CNS Tax Revenue**	**NNS Tax Revenue**	**Total Tax Revenue**
2002	-6.30	-21.60	-10.80	**-38.70**
2003	-5.72	-14.40	-7.20	**-27.32**
2004	1.48	-8.99	-6.76	**-14.28**
2005	12.23	1.49	5.00	**18.71**
2006	14.30	7.66	5.21	**27.17**
2007	15.30	10.22	3.39	**28.91**
2008	14.49	17.61	7.79	**39.89**
2009	18.77	26.68	16.12	**61.58**
2010	17.94	30.88	27.35	**76.17**
2011	18.36	24.24	22.19	**64.79**
2012	14.14	22.16	15.80	**52.10**
2013	7.90	18.83	8.21	**34.93**
2014	5.04	17.31	6.59	**28.94**
2015	5.34	12.97	7.16	**25.47**
2016	5.51	7.85	1.65	**15.01**
2017	0.93	1.88	0.23	**3.04**
2018	0.17	3.19	1.46	**4.82**
2019	-4.83	-0.58	0.54	**-4.87**
2020	-2.49	-3.55	0.63	**-5.41**
2021	0.00	-2.33	-3.52	**-5.85**
2022	0.00	0.00	-1.21	**-1.21**
Total £M	**132.55**	**151.51**	**99.81**	**383.88**

10.3 Table 49 below shows the take under the $12/bbl and 12p/therm case.

Table 49

Tax Take from Projected SEA2 Activity (£m, 2001)				
Real 2001	**SNS Tax Revenue**	**CNS Tax Revenue**	**NNS Tax Revenue**	**Total Tax Revenue**
2002	-6.30	-21.60	-10.80	**-38.70**
2003	-6.30	-14.40	-7.20	**-27.90**
2004	-2.33	-10.80	-7.20	**-20.33**
2005	5.10	-2.36	0.00	**2.74**
2006	5.09	1.94	0.00	**7.03**
2007	6.53	2.54	-3.26	**5.81**
2008	5.44	3.26	-0.72	**7.97**
2009	2.28	7.40	2.48	**12.16**
2010	3.51	11.47	1.99	**16.96**
2011	4.50	6.69	1.12	**12.31**
2012	1.72	3.51	0.71	**5.94**
2013	-1.34	2.48	0.58	**1.72**
2014	-1.64	2.88	0.38	**1.63**
2015	-0.46	1.96	0.16	**1.66**
2016	0.41	0.00	-1.55	**-1.14**
2017	0.40	-3.20	-1.61	**-4.40**
2018	0.39	-1.32	0.00	**-0.93**
2019	-1.22	-2.47	0.00	**-3.68**
2020	-1.12	-1.29	0.00	**-2.42**
2021	0.00	0.00	0.00	**0.00**
2022	0.00	0.00	0.00	**0.00**
Total £M	**14.66**	**-13.32**	**-24.91**	**-23.57**

Under the low price scenario government tax revenues from the SEA 2 area are likely to be negative.

11.0 General Conclusions

11.1 With real oil prices of $20 per barrel and gas prices of 18 pence per therm licensing of the SEA2 area could lead to the cumulative production of over 420 million extra barrels of oil and 790 billion extra cubic feet of gas. Total extra development expenditure could amount to around £925 million at 2001 prices. Extra operating expenditures could amount to over £880 million at 2001 prices. Extra employment will be generated throughout the industry supply chain in the period 2002-2020 with the peak being in 2009 at nearly 9,000 jobs.

11.2 Over the last few years the employment trend in the North Sea industry has been downwards. The planned licensing round would make a worthwhile contribution towards moderating the pace of employment decrease. Currently the industry is facing serious skill shortage and recruitment problems. One of the reasons for the recruitment problem is the perception that the North Sea industry is mature or "sunset", and does not offer interesting long-term employment opportunities. The effects of the proposed round would be to extend the employment time horizons for a significant number of employees in the industry. This could also result in an increase in the rate of return from investment in training.

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Appendix I

Abbreviations

Capital Expenditure:	Development costs excluding development drilling.
CNS:	Central North Sea
Development Costs:	All field development costs including drilling and other capital expenditure.
Mmcfd:	Million cubic feet per day
NNS:	Northern North Sea
NPV:	Net Present Value
Opex:	Operating costs
SNS:	Southern North Sea
tb/d:	Thousand barrels per day
Technical reserves:	Discovery not yet developed nor currently being considered for development.