SORP

Statement of Recommended Practice

Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities

Updated 7th June 2001

A SORP issued by the Oil Industry Accounting Committee incorporating and updating guidance set out in the SORP issued January 2000 and any subsequent Guidance Notes

Statement by the Accounting Standards Board (ASB)

The aims of the Accounting Standards Board (the ASB) are to establish and improve standards of financial accounting and reporting, for the benefit of users, preparers, and auditors of financial information. To this end, the ASB issues accounting standards that are primarily applicable to general purpose company statements. In particular industries or sectors, further guidance may be required in order to implement accounting standards effectively. This guidance is issued, in the form of Statements of Recommended Practice (SORPs), by bodies recognised for the purpose by the ASB.

The Oil Industry Accounting Committee (OIAC) has confirmed that it shares the ASB's aim of advancing and maintaining standards of financial reporting in the public interest and has been recognised by the ASB for the purpose of issuing SORPs. As a condition of recognition, OIAC has agreed to follow the ASB's code of practice for bodies recognised for issuing SORPs.

The code of practice sets out procedures to be followed in the development of SORPs. These procedures do not include a comprehensive review of the proposed SORP by the ASB, but a review of limited scope is performed.

On the basis of its review, the ASB has concluded that the SORP has been developed in accordance with the ASB's code of practice and does not appear to contain any fundamental points of principle that are unacceptable in the context of present accounting practice or to conflict with any accounting standard or the ASB's plans for future standards.

The Accounting Standards Board
Holborn Hall
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London WC1X 8AL

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Part 1 : Explanatory note

INTRODUCTION

1. The Oil Industry Accounting Committee ('OIAC') was established in 1984 to develop and promulgate guidance for the UK upstream oil and gas industry with the aim of advancing and maintaining standards of financial accounting and reporting.

2. The OIAC was authorised, initially, by the Accounting Standards Committee and subsequently by its successor, the Accounting Standards Board (ASB) to develop Statements of Recommended Practice (SORPs) and Guidance Notes for the preparation of financial statements for shareholders. This arrangement requires OIAC to follow the ASB's code of practice for the production and issuing of SORPs. This code of practice provides a framework to be followed by the OIAC for the development of SORPs, but does not entail a detailed examination of the proposed SORP by the ASB. However, a review of limited scope is performed. This SORP has been seen by The Financial Sector and Other Special Industries Committee of the ASB which has raised no objection to its publication.

   The OIAC issued four SORPs and two guidance notes between 1986 and 1998. In January 2000, following a period of substantial increase in the numbers of Financial Reporting Standards (FRSs), issued by the ASB, OIAC rationalised its previous pronouncements into a single combined SORP, superseding all earlier statements

3. The ASB code of practice on the development of SORPs requires, inter alia, that SORP-making bodies keep under review all SORPs for which they are responsible. In particular, the SORPs must comply with new accounting standards as they are introduced and reflect any new developments in the industry on which guidance may be needed.

4. This new SORP incorporates the FRS 15 *Tangible Fixed Assets* guidance issued by OIAC in September 2000. It also reflects other changes identified by the ASB, OIAC or its oil and gas industry

constituency as appropriate for further guidance. No industry specific issues were identified in FRS 16 *Current Tax*, the last FRS to be issued at the time this statement was prepared.

5. Readers' attention is particularly drawn to paragraphs 78 and 82, relating to impairment test discounting of revenues and costs, to paragraph 121 Underlift and Overlift, to paragraph 124, relating to the disclosure of oil trading sales and costs, to paragraphs 157 to 161 relating to production sharing agreements and to paragraphs 183 to 188, relating to redeterminations, where new recommended practices have been incorporated. Once this SORP comes into effect, the January 2000 SORP will be formally withdrawn.

OBJECTIVE

6. The objective of this SORP is to promote consistency amongst companies reporting under UK Accounting and Financial Reporting Standards as regards the effective application of these standards to their oil and gas exploration and production activities.

SCOPE AND APPLICATION

7. This statement of recommended practice applies to the financial statements of all companies reporting under UK generally accepted accounting principles with oil and gas exploration, development and/or production activities whether or not these activities take place in the UK. The recommendations only apply to material items.

8. This statement does not seek to set out all of the reporting requirements which apply to companies reporting under UK financial reporting standards with oil and gas exploration, development and/or production activities and is intended to complement, not replace, accounting standards[1] and companies legislation. This statement should not be used on a standalone basis, but rather should be referred to in conjunction with accounting standards and companies legislation. In the event of conflict accounting standards and companies legislation take precedence over this SORP.

[1] Comprising Financial Reporting Standards (FRSs), Statements of Standard Accounting Practice and Urgent Issues Task Force Abstracts

Part 2 : Definition of terms

9. ALLOCABLE TAXES. Taxes which can be specifically identified with oil and gas production activities.

10. CARRIED INTEREST. An arrangement whereby one or more members of a consortium are financed by other members during the exploration and/or development phase, with repayment only being required out of future production (if any).

11. CEILING TEST. See ‘impairment test’.

12. COMMERCIAL RESERVES. Commercial reserves may, at a company’s option, be taken as either:

(a) Proven and probable oil and gas reserves; or

(b) Proved developed and undeveloped oil and gas reserves;

both of which are defined below. These alternative definitions are mutually exclusive and the option chosen should be applied consistently in respect of all exploration, development and production activities.

(a) Proven and probable oil and gas reserves

Proven and probable reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty (see below) to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 per cent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 per cent statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proven and probable reserves are 90 per cent and 10 percent respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;

- a reasonable expectation that there is a market for all or substantially all the expected hydrocarbon production; and

- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Furthermore

(i) Reserves may only be considered proven and probable if producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proven includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proven and probable classification when successful testing by a pilot project, the operation of an installed programme in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or programme was based.

(b) Proved developed and undeveloped oil and gas reserves
The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as at the date the estimate is made.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves that can be produced economically through the application of improved recovery techniques (such as fluid injection) are generally only included in the ‘proved’ classification if successful testing by a pilot project, or the operation of an installed programme in the reservoir, provides support for the engineering analysis on which the project or programme was based.

(iii) Estimates of proved reserves do not include the following: (a) crude oil, natural gas and natural gas liquids that may become available from known reservoirs but are classified separately as indicated additional reserves; (b) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (c) crude oil, natural gas and natural gas liquids that may occur in undrilled prospects; and (d) crude oil, natural gas and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved reserves may be sub-divided into 'proved developed' and 'proved undeveloped':

(i) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should generally be included as proved developed reserves only after testing by a pilot project or after the operation of an installed programme has confirmed through production response that increased recovery will be achieved.

(ii) All other proved reserves which do not meet this definition are proved undeveloped.

13. COST POOL. A cost centre used under the full cost method of accounting as a basis for accumulating depreciable capitalised exploration, appraisal and development expenditure and for performing an impairment test. The cash flows from fields within a pool must be affected by the same factors and therefore the fields within a pool will possess to a significant degree common characteristics in at least one of the following factors: geological area, interdependence of infrastructure, common economic environment or common development of markets.

14. COSTS.

(a) Pre-licence costs

Cost incurred in the period prior to the acquisition of a legal right to explore for oil and gas in a particular location. Such costs include the acquisition of speculative seismic data and expenditure on the subsequent geological and geophysical analysis of this data.

(b) Licence acquisition costs

Costs incurred to purchase, lease or otherwise acquire a property including the costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to petroleum when land including petroleum rights is purchased, including brokers' fees and legal and other related costs.

(c) Exploration and appraisal costs

Costs incurred after obtaining a licence or concession but before a decision is taken to develop a field or reservoir, including the costs of:

- geological and geophysical studies;
- holding undeveloped properties; and
- drilling, equipping and testing exploration and appraisal wells. Appraisal costs are those incurred in determining the size and characteristics of a reservoir discovered during the exploration stage and then assessing its commercial potential.

(d) Development costs

Costs incurred after a decision has been taken to develop a reservoir, including the costs of:

- drilling, equipping and testing development and production wells;
- production platforms, downhole and wellhead equipment, pipelines, production and initial treatment and storage facilities and utility and waste disposal systems; and
- improved recovery systems and equipment.

(e) Operating costs

Operating costs are the costs of producing oil and gas, including:

- costs of personnel engaged in the operation of wells and related equipment and facilities;

- repairs and maintenance of producing facilities; and

- materials, supplies and fuel consumed and services utilised in such operations.

15. DECOMMISSIONING. The process of plugging and abandoning wells, dismantlement of wellhead, production and transport facilities and restoration of producing areas in accordance with licence requirements and/or relevant legislation.

16. FARM IN. The transfer of part of an oil and gas interest in consideration for an agreement by the transferee ('farmee') to meet, absolutely, certain expenditure which would otherwise have to be undertaken by the owner ('farmor').

17. FIELD. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

18. FULL COST ACCOUNTING. A method of accounting for oil and gas exploration and development activities whereby all costs associated with exploring for and developing oil and gas reserves are capitalised, irrespective of the success or failure of specific parts of the overall exploration activity. Costs are accumulated in cost centres known as 'cost pools' and the costs in each cost pool are written off against income arising from production of the reserves attributable to that pool.

19. IMPAIRMENT.

(a) Of capitalised development costs;

a change in circumstances leading to a conclusion that the recoverable amount from reserves associated with capitalised development costs is likely to be less than the amount at which those costs are carried in the books – assessed by means of an impairment test, see below.

(b) Of costs capitalised pending determination, ie costs capitalised whilst a field is still being appraised;

a change in circumstances leading to a conclusion that there is no longer a reasonable prospect that commercial reserves will result and will be developed – reached in accordance with the guidance in this statement.

20. IMPAIRMENT TEST. A test in accordance with FRS 11 to assess the recoverability of the amounts at which capitalised exploration, appraisal and development expenditure associated with an income generating unit are recorded in the books by comparing that amount with the recoverable amount generally being the present value of future cash flows obtainable as a result of the continued use of that income generating unit, often referred to as a 'ceiling test' by the industry.

21. INCOME GENERATING UNIT. The group of assets, liabilities and associated goodwill that generates income that is largely independent of a reporting entity's other income streams, as defined in FRS 11. Under successful efforts accounting policies, the income generating unit will generally be the assets, liabilities and associated goodwill associated with a particular field, or under some circumstances a group of fields that are to a significant degree economically interdependent. Under full cost accounting policies, the income generating unit will generally be the cost pool.

22. JOINT ARRANGEMENT (equivalent to a 'joint venture' in common oil and gas industry terminology). A contractual arrangement by which a number of participants agree to conduct oil and gas exploration and production activities jointly, as a consortium. The terms of the joint arrangement are generally set out in a 'joint operating agreement' such that all significant matters of operating

and financial policy are predetermined. Under the joint operating agreement, the operator is elected to manage the assets and is generally empowered to enter into contracts and incur costs which are rechargeable to the other participants. Such an upstream oil and gas industry 'joint venture' will typically fall within the FRS 9 definition of a 'joint arrangement which is not an entity' (FRS 9 paragraph 4 and paragraphs 8 and 9), and not within the FRS 9 definition of a 'joint venture' (FRS 9 paragraph 4 and paragraph 10) which is used to describe a significantly different type of business structure.

23. LICENCE. The right to explore for and exploit hydrocarbon reserves within a defined area. For the purposes of this statement, this term should be taken to include leases, concessions and other similar means by which this right may be granted or acquired.

24. LIFE-OF-FIELD METHOD. One of the methods of computing provisions for oil taxation, e.g. Petroleum Revenue Tax, by estimating the total tax payable over the life of a field and providing for the liability on a unit-of-production or similar basis.

25. OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES. Those activities that involve the acquisition of interests in petroleum licences and properties, exploration, appraisal and development of crude oil reserves, including condensate and natural gas liquids, and natural gas.

26. PROVED PROPERTIES. Licences, concessions or leases which have proved reserves.

27. PRT. UK Petroleum Revenue Tax.

28. REDETERMINATION. A retroactive adjustment to the relative percentage interests of the participants in a field.

29. RESERVOIR. A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

30. SUCCESSFUL EFFORTS ACCOUNTING. A method of accounting for oil and gas exploration and development activities whereby exploration expenditure which is either general in nature or relates to unsuccessful drilling operations is written off. Only costs which relate directly to the discovery and development of specific commercial oil and gas reserves are capitalised and are depreciated over the lives of these reserves. The success or failure of each exploration effort is judged on a well-by-well basis as each potentially hydrocarbon-bearing structure is identified and tested.

31. UNIT-OF-PRODUCTION. A method of computing charges by reference to the ratio that quantities of production in a period bear to the quantities of reserves remaining at the end of that period plus production in the period.

32. UNPROVED PROPERTIES. Licences, concessions or leases which do not have proved reserves.

33. WELLS.

(a) Exploration well;

A well drilled to discover whether oil or gas exists in a previously unproved geological structure.

(b) Appraisal well;

A well drilled to determine the size, characteristics and commercial potential of a reservoir discovered by the drilling of an exploration well.

(c) Development well;

A well drilled within the area of a proved reservoir to facilitate the production of reserves. Such wells may either be intended to produce oil and gas directly or to facilitate such production by, for example, the injection of gas or water. All wells drilled after a decision to develop a field has been made will ordinarily constitute development wells.

Part 3 : Recommended practice

PRE-PRODUCTION ACTIVITIES & DECOMMISSIONING

Full cost and successful efforts principles

34. Oil and gas exploration and development activities have several distinctive features:

- the risks of exploration are high and there is often a low probability of discovering commercial reserves in any individual location;

- the elapsed time between initial exploration, the assessment of whether commercial reserves exist and the bringing of such reserves, if any, into production may be several years, particularly in offshore environments;

- there is no necessary correlation between exploration and development expenditure incurred, whether capitalised or otherwise, and the value of oil and gas reserves discovered as a result of those activities; and

- the major economic value lies in the underlying oil and gas reserves which typically are not recorded in company balance sheets.

35. These and other factors historically resulted in the development of a wide range of practices as companies sought to provide a proper accounting presentation of the underlying activities. These practices have been narrowed into two categories – 'full cost' and 'successful efforts'.

36. Under successful efforts accounting, exploration expenditure which is general in nature is charged directly to the profit and loss account and

that which relates to unsuccessful drilling operations, though initially capitalised pending determination, is subsequently written off. Only costs which relate directly to the discovery and development of specific commercial oil and gas reserves will remain capitalised to be depreciated over the lives of these reserves. The success or failure of each exploration effort will be judged on a well-by-well basis as each potentially hydrocarbon-bearing structure is identified and tested.

37. Under full cost accounting, all costs associated with exploring for and developing oil and gas reserves are capitalised, irrespective of the success or failure of specific parts of the overall exploration activity. Costs are accumulated in cost centres (known as 'cost pools'). The costs in each cost pool are generally written off against income arising from production of the reserves attributable to that pool.

38. The differences between the two methods outlined above reflect the differing perceptions which may be taken by companies of their exploration activities, in particular the issue of whether distinct exploration activities should be viewed as separate efforts to locate commercial reserves - the successful efforts method - or as part of an overall effort in a defined area - the full cost method.

39. The consequence is that there is a difference in the timing of income recognition. Under the successful efforts method, the costs of individually unsuccessful efforts are usually written off earlier in the financial statements but greater reported profits will be shown once production starts. Under the full cost method, the total costs of both successful and unsuccessful activities are spread over total production from each pool. Over the life of the entity aggregate reported profits under each method will be the same, but profits under full cost would tend to be recognised earlier.

40. Both full cost and successful efforts are considered to be acceptable accounting methods and companies should adopt that policy which they consider to be most suitable to their operations. The accounting practice under each of these methods is recommended in this statement based on the research of the OIAC into actual practices followed and the various alternatives considered acceptable to the UK industry. Practices followed in other countries have also been taken into account.

Initial treatment of costs pending determination

<u>Full cost companies</u>

41. Expenditure on pre-licence, licence acquisition, exploration, appraisal and development activities including enhanced oil recovery and extended life projects should be capitalised.

42. In accordance with FRS 15, Tangible Fixed Assets, all other costs should be expensed as incurred including operating and production-related costs, such as tariffs and royalties, and also administrative and other general overhead costs not directly attributable to the activities referred to in paragraph 41.

43. All capitalised exploration and development expenditure should be recorded within an appropriate cost pool when incurred, except that certain exploration and appraisal costs may be held outside cost pools pending determination.

44. Pre-licence acquisition, exploration and appraisal costs of individual licence interests may be held outside cost pools until the existence or otherwise of commercial reserves is established. These costs will therefore remain undepreciated pending determination, subject to there being no evidence of impairment.

45. Costs initially held outside cost pools must be transferred to the relevant pool, and depreciated, in the following circumstances:

- when there are indications of impairment; all expenditure must be subjected to a test for impairment at least annually. Costs capitalised pending determination of whether or not they have found commercial reserves are, where accounted for in accordance with this statement, specifically exempt from the detailed rules for assessing impairment set out in FRS 11;

- at the conclusion of an appraisal programme whether or not commercial reserves are discovered.

The possibility of impairment must be considered if in the case of licence acquisition costs there is no drilling after one year or, in the case of successful exploration wells requiring further appraisal, such appraisal does not take place within two years of the discovery being made. The determination of drilling costs should be on a well-by-well basis except that all appraisal wells in respect of a discovery may be determined together.

46. The basis under which cost pools are established, for example geographic area, region or country, should be disclosed as an accounting policy. Cost pools should not normally be smaller in size than a country (except where significant interests are subject to widely differing geological, infrastructure, economic or market factors, for example onshore and offshore interests) and should be restricted in size so as to encompass a geographical area which shares a significant degree of common characteristics in at least one of the following factors: geological area, interdependence of infrastructure, common economic environment or common development of markets. The following are examples of what may be acceptable full cost pools:

(a) Northern South America contains effectively one geological province: the so-called Sub-Andean Province. Although the area covers a number of different countries, it is significantly affected by similar geological risks throughout.

(b) Similarly the NW European Continental Shelf has common geological characteristics extending beyond national boundaries, as well as having an increasing amount of shared infrastructure.

(c) Although Russia contains a number of geological basins, these are linked by common political, economic, legal and fiscal systems as well as shared infrastructure.

(d) The Caspian region comprises a number of separate countries, but they are closely linked commercially by a common export system, shared exploration resources and by the parallel development of new markets.

In each of these and in other similar cases where an area is managed as a single unit with its own dedicated team and internal reporting requirements, it may be appropriate to treat the area as a single income generating unit and therefore a single cost pool. A world-wide pool containing areas with very different characteristics, would not qualify as a single income generating unit, and a world-wide pool of this kind would therefore be inappropriate.

47. Changes in either the physical size or number of pools within an established policy must be warranted by business developments or changes in infrastructure, economic or market factors affecting the business. The reasons for any changes should be reported and the consequent effect on the company's earnings should be disclosed in the financial statements of the current period.

48. The aggregate net book value of full cost pools should be disclosed, together with the aggregate of costs held outside cost pools.

49. Full cost pools should be classified in the balance sheet as 'tangible assets'. Expenditure held outside full cost pools should be classified as 'intangible assets - exploration expenditure'.

Successful efforts companies

50. All pre-licence, licence acquisition, exploration and appraisal costs should initially be capitalised (including those costs which may fall to be written off in the same period such as those costs referred to in paragraph 51) in well, field or general exploration cost centres as appropriate, pending determination. Expenditure incurred during the various exploration and development phases should then be written off unless commercial reserves have been established or the determination process has not been completed.

51. Expenditure incurred prior to the acquisition of a licence and the costs of other exploration activities which are not specifically directed to an identified structure should be written off in the period.

52. Expenditure incurred on the acquisition of a licence interest should initially be capitalised on a property-by-property basis.

53. Exploration and appraisal costs should be accumulated on a well-by-well basis pending evaluation. Capitalised costs should be considered abortive and written off on completion of a well unless the results of drilling indicate that hydrocarbon reserves exist and there is a reasonable prospect that these reserves are commercial. Where such reserves exist, the costs of unsuccessful appraisal wells may remain capitalised where further appraisal of the discovery is planned. If this further appraisal does not lead to the discovery of commercial reserves, all these costs should be written off.

54. After appraisal, if commercial reserves are found then the net capitalised costs incurred in discovering the field should be transferred into a single field cost centre. Any subsequent development costs, including, if desired, the costs of dry delineation and other dry development wells, should be capitalised in this cost centre.

55. All other costs should be expensed as incurred including operating and production-related costs, such as tariffs and royalties, and also administrative and other general overhead costs not directly attributable to the activities referred to in paragraph 50.

56. Unless further appraisal of the prospect is firmly planned or underway, expenditure incurred on exploration and appraisal activities may be carried forward pending determination for a maximum of three years following completion of drilling in an offshore or frontier environment where major development costs may need to be incurred or for a maximum of two years in other areas. In exceptional circumstances, these time limits may be inappropriate but, having regard to the intent of successful efforts accounting, any undetermined costs carried forward beyond these limits should be disclosed. Costs capitalised pending determination of whether or not they have found commercial reserves are, where accounted for in accordance with this statement, specifically exempt from the detailed rules for assessing impairment set out in FRS 11.

57. Subsequent to the appraisal of a field, expenditure incurred in establishing commercial reserves may be carried forward only as long as there exists a clear intention to develop the field. The inclusion of a field development plan within the company's overall business plan would be evidence of such intention.

58. All exploration and development expenditure should be capitalised as additions to fixed assets in the period in which it is incurred. This includes expenditure which is subsequently written off during that period.

59. Exploration and appraisal expenditure on a property should be classified in the financial statements as 'intangible assets-exploration expenditure', pending evaluation. When the existence of commercial reserves is established, directly related exploration and appraisal expenditure should be reclassified in the financial statements under the heading 'tangible assets'. Subsequent field development costs should be classified as tangible assets.

Subsequent expenditure

60. FRS 15 states, in paragraph 34 that 'subsequent expenditure to ensure the tangible fixed asset maintains its previously assessed standard of performance should be recognised in the profit and loss account as it is incurred.' Subsequent expenditure should be capitalised where it enhances the economic benefits of the tangible fixed assets. An example in the oil and gas industry is where expenditure is associated with additional oil and gas reserves or allows accelerated production. Expenditure relating to workovers should be reviewed on a case by case basis and capitalised only if it enhances the original performance of the tangible fixed asset.

Finance costs

61. Finance costs may be capitalised in accordance with the rules set out in

FRS 15 *Tangible Fixed Assets*.

Bottom hole contributions

62. Bottom hole contributions involve a payment to an operator as a contribution to the cost of drilling a well on a licence in which the contributor has no property interest, in exchange for information on the results of the well. The contributions are normally payable when the well reaches a predetermined depth, irrespective of whether it is successful or otherwise.

63. The contributor should account for the cost as it would for other preproduction costs. The company receiving the contribution should credit the receipt against the cost of the well.

Capitalisation of future decommissioning costs provided

64. The future cost of decommissioning an installation, provided for in accordance with paragraphs 89 to 99 of this statement, should be regarded as part of the total investment to gain access to future economic benefit. Thus a 'decommissioning asset' should be established and should be included as part of the overall cost pool or field cost centre.

65. The decommissioning asset should be recognised and capitalised as the related facilities are installed, simultaneously with the recognition of the provision, and in the phased manner described in paragraph 94 of this statement where appropriate. The incremental amount capitalised on each phase of installation should equal the incremental amount provided in respect of each phase.

66. Where a decommissioning asset has previously been recognised, a change in provision due to a change in the estimate or the assumptions underlying it should be treated as an adjustment to the decommissioning asset included within the overall cost pool or field cost centre.

67. In exceptional circumstances, an adjustment to the decommissioning provision for a facility may reduce the overall net book value of the cost pool or field cost centre to below zero. In such cases, the amount of the adjustment which would otherwise have given rise to a negative net book value should be taken to the profit and loss account.

Depreciation

<u>Full cost companies</u>

68. All expenditure carried within each cost pool should be depreciated on a unit-of-production basis by reference to quantities.

69. The depreciation charge should be calculated on a pool-by-pool basis, using the ratio of oil and gas production in the period to the estimated quantity of commercial reserves at the end of the period plus the production in the period. Where both oil or gas or other hydrocarbons exist in material quantities it is necessary to use an appropriate conversion factor so that aggregate reserves and production can each be expressed in a common unit. The figures both for production and commercial reserves should consistently either include or exclude any quantities of oil or gas consumed in operations.

70. The cost element of the unit-of-production calculation should be the costs incurred to date together with the estimated future development costs of obtaining access to all the reserves included in the unit-of-production calculation. Thus it should represent the net book amount of capitalised costs incurred to date, plus the anticipated future field development costs which should be stated at current period-end unescalated prices.

71. Future decommissioning costs capitalised as part of the cost of the related installation should be depreciated on a unit-of production basis in the same way as other costs capitalised within the pool.

72. Changes in cost and reserve estimates do not give rise to prior year adjustments. Where estimates are revised, the carrying amount should be depreciated using the revised estimates from the date of the revision.

Successful efforts companies

73. Licence acquisition costs which have not been allocated should be depreciated over a maximum period of the licence. The net book amount of undepreciated licence acquisition costs should be reviewed annually for impairment on a property-by-property basis. Any impairment identified should be written off. Costs capitalised pending determination of whether or not they have found commercial reserves are, where accounted for in accordance with this statement, specifically exempt from the detailed rules for assessing impairment set out in FRS 11.

74. All expenditure carried within each field should be depreciated on a unit-of-production basis by reference to quantities. The basis should be the ratio of oil and gas production in the period to the estimated quantity of commercial reserves on a field-by-field basis at the end of the period plus the production in the period. Where both oil and gas or other hydrocarbons exist in material quantities it is necessary to use an appropriate conversion factor so that aggregate reserves and production can each be expressed in a common unit. The figures both for production and commercial reserves should consistently either include or exclude any quantities of oil or gas consumed in operations.

75. The cost element of the unit-of-production calculation should be the costs incurred to date together with the estimated future development costs of obtaining access to all the reserves included in the unit-of-production calculation. Thus it should represent the net book amount of capitalised costs incurred to date, plus the anticipated future field development costs which should be stated at current period-end unescalated prices.

76. Future decommissioning costs capitalised as part of the cost of the related installation should be depreciated on a unit-of-production basis in the same way as other capitalised costs.

77. Changes in cost and reserve estimates do not give rise to prior year adjustments. Where estimates are revised, the carrying amount should be depreciated using the revised estimates from the date of the revision.

Impairment tests

Full cost companies

78. An impairment test should be carried out if events or changes in circumstances indicate that the net book amount of expenditure within each cost pool, less any provisions for decommissioning costs and deferred production or revenue-related taxes[2], may not be recoverable from the anticipated future net revenue from oil and gas reserves attributable to the company's interest in that pool. Since, under the full cost method, the pool is the recorded asset for Companies Act purposes and should be defined so as to qualify as an income generating unit for the purposes of FRS 11, the test should be carried out on a pool-by-pool basis. Costs held outside the cost pools are subject to a separate review for impairment, as set out in paragraph 45above.

79. In undertaking calculations for the purposes of impairment tests, the following rules shall apply:

(a) cash flow projections should be prepared showing the estimated revenues from production of reserves together with future operating costs, future production or revenue-related taxes (including PRT), future insurance and royalties, future development costs and decommissioning costs. See paragraph 184 if a future redetermination of field interests is anticipated. A deduction should be made to reflect any quantities included as reserves which are expected to be consumed in operations. General financing costs and taxation on profits (including UK corporation tax) should not be included in the projections;

[2] Provisions for deferred income taxes attributable to the field should not be deducted.

(b) prices and cost levels used should be those expected to apply in future periods, rather than those ruling at the date the impairment test is applied; and

(c) either the estimates of future cash flows should be directly adjusted to reflect the risks, or appropriately risk adjusted discount rates should be applied to the cash flows. Where risk is reflected in the discount rate, estimates of future revenues and costs should each be discounted at a rate appropriate to that cash stream. In particular:

(i) FRS 11 does not preclude the use of discount rates commonly used within the industry to value similar assets. However, the discount rates should be consistent with the other assumptions reflected in the impairment test;

(ii) where specific cash flows within the projections are affected significantly by a specific risk or uncertainty unique to those cash flows, then it will generally be inappropriate to reflect this risk by adjusting the discount rate applied to net cash flows. To the extent that probable reserves are included in projected revenues and a risk adjustment to the discount rate is to be used to reflect uncertainty, it is inappropriate to apply this same risk adjusted rate to costs in the projections which are not expected to be affected by whether or not probable reserves are ultimately recovered;

(iii) the discount rate applied for impairment test purposes in calculating the present value of future cash flows relating to decommissioning should be consistent with the rate used in the measurement of the decommissioning provision under paragraphs 92 and 93 of this statement. This rate may differ from the rate used to discount future net revenues, reflecting the differing risk profiles of those cash flows. Alternatively, the decommissioning cash flows and the related balance sheet provision may be removed from the impairment test; and

(iv) if cash flows are estimated using prices expected to apply in future periods, the discount rate should be a nominal one (i.e. also reflecting price increases).

(d) paragraph 38 of FRS 11 requires the costs and benefits of future capital expenditure to be excluded only to the extent that the expenditure will improve the fields which comprise the pool in excess of their originally assessed standard of performance. This requirement does not prevent oil and gas exploration companies from taking account of future capital expenditure required to fully exploit the reserves estimated to be present at the time of developing a new field, or in developing an identified field extension. There must be clear evidence that the development plan pre existed the indication of impairment.

80. A deficiency identified as the result of an impairment test must be provided and charged in the current period as additional depreciation and taxation provisions should be adjusted as appropriate. In certain circumstances the additional depreciation may need to be disclosed as an exceptional item. The disclosure requirements associated with an impairment are set out in paragraphs 69 - 73 of FRS 11 'Impairment of Fixed Assets and Goodwill'.

81. If there is a change in economic conditions or in the expected use of an asset that reverses a previous impairment, the asset's value should be restored in the balance sheet in accordance with the FRS. The asset's value should not be restored if the increase in value arises simply because of the passage of time or the occurrence of previously forecast cash outflows.

Successful efforts companies

82. An impairment test should be carried out if events or changes in circumstances indicate that the net book amount of expenditure within each cost centre, less any provisions for decommissioning costs and deferred production or revenue-related taxes[3], may not be

[3] Provisions for deferred income taxes attributable to the field should not be deducted.

recoverable from the anticipated future net revenue from oil and gas reserves attributable to the company's interest in that field. Since, under successful efforts accounting, the field is the recorded asset for Companies Act purposes, the test should generally be carried out on a field-by-field basis. In certain circumstances, for example where two or more fields use common production and transportation facilities, those fields may be sufficiently economically interdependent to constitute a single income generating unit for the purposes of FRS 11, in which case impairment test should be performed in aggregate for those fields. Costs held pending determination are subject to a separate review for impairment, as set out in paragraph 56 above.

83. In undertaking calculations for the purposes of impairment tests, the following rules shall apply:

(a) cash flow projections should be prepared showing the estimated revenues from production of reserves together with future operating costs, future production or revenue-related taxes (including PRT), future insurance and royalties, future development costs and decommissioning costs. See paragraph 184 if a future redetermination of field interests is anticipated. A deduction should be made to reflect any quantities included as reserves which are expected to be consumed in operations. General financing costs and taxation on profits (including UK corporation tax) should not be included in the projections;

(b) prices and cost levels used should be those expected to apply in future periods, rather than those ruling at the date the impairment test is applied; and

(c) either the estimates of future cash flows should be directly adjusted to reflect the risks, or appropriately risk adjusted discount rates should be applied to the cash flows. Where risk is reflected in the discount rate, estimates of future revenues and costs should each be discounted at a rate appropriate to that cash stream. In particular:

(i) FRS 11 does not preclude the use of discount rates commonly used within the industry to value similar assets. However, the discount rate should be consistent with the other assumptions reflected in the impairment test;

(ii) where specific cash flows within the projections are affected significantly by a specific risk or uncertainty unique to those cash flows, then it will generally be inappropriate to reflect this risk by adjusting the discount rate applied to net cash flows. To the extent that probable reserves are included in projected revenues and a risk adjustment to the discount rate is to be used to reflect uncertainty, it is inappropriate to apply this same risk adjusted rate to costs in the projections which are not expected to be affected by whether or not probable reserves are ultimately recovered;

(iii) the discount rate applied for impairment test purposes in calculating the present value of future cash flows relating to decommissioning should be consistent with the rate used in the measurement of the decommissioning provision under paragraphs 92 and 93 of this statement. This rate may differ from the rate used to discount future net revenues, reflecting the differing risk profiles of those cash flows. Alternatively, the decommissioning cash flows and the related balance sheet provision may be removed from the impairment test; and

(iv) if cash flows are estimated using prices expected to apply in future periods, the discount rate should be a nominal one (i.e. also reflecting price increases).

(d) paragraph 38 of FRS 11 requires the costs and benefits of future capital expenditure to be excluded only to the extent that the expenditure will improve the fields which comprise the pool in excess of their originally assessed standard of performance. This requirement does not prevent oil and gas exploration companies from taking account of future capital expenditure required to fully exploit the reserves estimated to be present at the time of developing a new field, or in developing an identified field extension. There must be clear evidence that the development plan pre existed the indication of impairment.

84. A deficiency identified as the result of an impairment test must be provided and charged in the current period as additional depreciation and taxation provisions should be adjusted as appropriate. In certain circumstances the additional depreciation may need to be disclosed as an exceptional item. The disclosure requirements associated with an impairment are set out in paragraphs 69 - 73 of FRS 11 'Impairment of Fixed Assets and Goodwill'.

85. If there is a change in economic conditions or in the expected use of an asset that reverses a previous impairment, the asset's value should be restored in the balance sheet in accordance with the FRS. The asset's value should not be restored if the increase in value arises simply because of the passage of time or the occurrence of previously forecast cash outflows.

<u>Non-recourse project finance and impairment tests</u>

86. FRS 11 contains no reference to the impact of non-recourse project finance on an impairment calculation.

87. To the extent that any impairment will be borne by a non-recourse finance provider, the FRS does not preclude the debt being adjusted to record the lower amount that will be repaid and offsetting that adjustment against the impairment loss. The impairment should therefore be calculated as follows where non-recourse financing is a factor:

(1) Calculate the quantum of impairment on a 'stand alone basis'

For example:

A project has a book value of £100m in the books of XYZ Ltd and is partly funded by £60m non-recourse finance. This £60m debt is due to be paid off over the life of the project and will have incurred £8m of interest by the time it is fully repaid. The present value of the future cash flows from the project is £70m.

Interest on the debt and debt repayment should be ignored in calculating the 'stand alone basis' present value of future cash flows.

On a stand alone basis the impairment in the above example is therefore £30m (£100m - £70m).

(2) Assess whether any element of the impairment will be borne by the non-recourse finance provider.

This will depend on the terms of the non-recourse finance.

In most cases the non-recourse finance will be repaid first out of the cash flows from the project. In the above example, under such terms, all of the impairment, £30m, would be borne by XYZ Ltd as the debt, and interest thereon, can be fully repaid. The debt will only be reduced when the future cash flows from the project are insufficient to finance the loan repayments or interest on the debt.

If the non-recourse finance terms are such that the loan will not be fully repaid when an impairment is suffered then the debt should be adjusted accordingly. The effect of this adjustment should be disclosed in the notes to the accounts. This may be achieved by showing the unadjusted carrying value of the debt, with the amount of the impairment-related effect shown as an adjustment to arrive at the revised carrying amount (see also paragraph 165).

(3) Where the non-recourse finance is provided by another group company, then in the consolidated group accounts all of the impairment should be borne by the group.

Decommissioning[4]

Introduction

88. Decommissioning describes the process of plugging and abandoning wells, of dismantlement of wellhead, production and transport facilities and of restoration of producing areas in accordance with licence requirements and the relevant legislation.

Decommissioning liabilities

89. FRS 12 *Provisions, contingent liabilities and contingent assets* requires provision to be made for a present obligation whether that obligation is legal or constructive. FRS 12 specifically relates this concept to oil installations by examples, requiring provision for decommissioning costs 'to the extent that the entity is obliged to rectify [environmental] damage already caused'.

90. This means that a provision is required, subject to the measurement rules below, as soon as damage is done. The word 'damage' has a very broad application in FRS 12 and refers to any act, event or circumstance which requires to be rectified, either immediately or at some point in the future. Thus an offshore platform or laying of a pipeline is regarded as damage to the marine environment.

Measurement of the liability

91. FRS 12 requires provisions to be recorded at the present value of the expenditures expected to be required to settle the obligation where this is materially different from the undiscounted amount. Decommissioning provisions will therefore be discounted in most cases.

92. FRS 12 also requires that risks and uncertainties are taken into account in reaching the best estimate of a provision. It is recommended that this is achieved through discounting the estimated future decommissioning costs at a pre-tax, risk-free rate. Guidance in relation to discounting is available in the ASB's Discounting in Financial Reporting Working Paper. That paper suggests that the estimated amount to be discounted should be established as the 'expected value' of the cash outflows adjusted upward to reflect uncertainty.

93. That paper also describes an alternative approach, to arrive at the same result, using an unadjusted 'expected value' discounted at an adjusted (reduced) rate.

94. The decommissioning liabilities to be provided for are those for the facilities where 'damage' that will need to be rectified has been caused, for example production platforms that are already in place. The liability will exclude the decommissioning costs of facilities that are yet to be installed, such as future subsea completions of satellite fields.

95. FRS 12 requires account to be taken of all evidence as to the technology that will be available at the time of the decommissioning. This means that cost reductions expected to arise from increased experience of current technology or from applying the technology to larger projects can be considered. However, completely new technologies should not be anticipated.

Changes in estimates

96. Provisions should be reviewed at each balance sheet date to reflect the current best estimate of the cost at present value. A change in provision should be analysed between the unwinding of the discount and changes arising from any variation in the estimate or assumptions underlying it. The unwinding of the discount is dealt

[4] *Transitional rules.* There are no specific transitional provisions in FRS 12. The standard envisages that the initial application will in some circumstances entail a change in accounting policy and, in others, a correction of accounting estimate. OIAC expects that where no provision for decommissioning has been made, or where provision has been made in accordance with SORP 3, the application of FRS 12 will represent a change in accounting policy. In the majority of cases, therefore, adoption of FRS 12 will require a prior year adjustment in accordance with FRS 3.

with in a separate section below. Changes in estimates or assumptions may arise from a number of factors including variations in costs, discount rates and timing of decommissioning.

97. Where there is an adjustment to the provision as a result of a change in estimate, there should be a corresponding equal and opposite adjustment to the related 'decommissioning asset'.

Unwinding of discount

98. The unwinding of the discount is to be included as a financial item adjacent to interest but shown separately from other interest either on the face of the profit and loss account or in a note.

Residual values of assets

99. Residual values of assets that are to be decommissioned should not be offset against the decommissioning cost in establishing the decommissioning asset. The estimated residual values, (for example, for floating production vessels), should be taken into account in establishing the amortisation to be charged.

Consolidation adjustments

100. As described in paragraph 199, uniform group accounting policies should be used for determining the amounts to be reported in a company's consolidated accounts, if necessary by adjusting for consolidation the amounts which have been reported by subsidiary undertakings in their own accounts, so that the consolidated accounts reflect the group's accounting policies applied to the exploration and development activities of the group as a whole. A consistent definition of commercial reserves and consistent application of either full cost or successful efforts accounting policies should be applied throughout.

101. Accordingly, cost pools and fields should be regarded on a group basis for cost accumulation, impairment tests, impairment tests and depreciation calculations.

102. Separate depreciation calculations and impairment tests should be carried out for each subsidiary. The results of these calculations should be reflected in the accounts of the subsidiary, particularly where minority interests are involved. Exploration and development activities undertaken under a joint arrangement should be dealt with for accounting and reporting purposes as part of the company's activities.

103. The exploration and development activities of associates and entities which are joint ventures as defined in FRS 9 should not be taken into account when formulating a cost pool configuration or when computing a group depreciation charge, or when conducting impairment tests.

OIL AND GAS PRODUCTION ACTIVITIES

Introduction

104. The variety of risk and reward sharing arrangements existing in the oil and gas industry gives rise to a number of issues that affect the classification and presentation within the profit and loss account of various elements of operating income and expenditure.

Turnover, indirect taxes and excise duties

105. Turnover is a widely used indicator of the level of activity and, in many industries at least, is not susceptible to substantial variations in quantification based on the choice of accounting policies applied. In the oil and gas industry, however, there are a number of elements of overall revenue which may not necessarily be recorded as turnover.

106. The Companies Act 1985 (Schedule 4, Paragraph 95) defines Turnover as:

> 'the amounts derived from the provision of goods and services falling within the company's ordinary activities, after deduction of trade discounts, value added tax and any other taxes based on the amounts so derived'.

107. Host governments frequently impose fiscal arrangements linked directly to the gross values of oil and gas sold, such as indirect taxes, excise duties, production taxes and royalties. Such fiscal elements are often sufficiently large in relation to the underlying value of the oil and gas sold as to make comparisons between years and between companies very difficult if not misleading.

108. The general principle followed in this statement is that turnover for upstream operations should reflect only actual amounts invoiced in respect of sales of the company's own share of oil and gas production and related services rendered.

109. As regards indirect taxes and excise duties, there are two conflicting arguments. On the one hand their inclusion and separate identification within an analysis of reported turnover demonstrates to users the significance of this element of the overall sales price of the oil and gas and also of the company's role as a 'tax collector'. Turnover is then stated on a basis consistent with the amounts shown as trade debtors and the related tax liabilities are recorded within creditors. On the other hand such inclusion can be misleading as 'percentage taxes' exaggerate any fluctuation in underlying sales revenues and the effect of changes in tax rates may mask and outweigh trends in the actual values of oil and gas sold.

110. The OIAC believes that the disadvantages of the inclusion of such elements of gross revenue in reported turnover outweigh the advantages. Consequently, turnover should, therefore, be stated exclusive of indirect taxes and excise duties. If companies desire to publish the amounts of such items they should do so, in a note to the accounts, in the form of an analysis of gross revenues and deductions therefrom in arriving at reported turnover.

Royalties

111. Government and other royalties payable are sometimes excluded from both the value of reported turnover and cost of sales on the basis that the reporting company has no legal right to the royalty oil or gas. In other cases all invoiced quantities are included in turnover, and royalty payments are charged to cost of sales. Variations in treatment render comparisons difficult, not only as regards turnover but also as regards the relationship between turnover, production and net oil and gas reserve quantity movements.

112. The OIAC distinguishes two types of royalty arrangement meriting different accounting treatment:

(a) In some instances (e.g. UK Government royalties), the royalty arrangements are such that the reporting company is obliged to dispose of all of the relevant production and to pay over that proportion of the aggregate proceeds of sale in each reporting period which represents the royalty liability, often after deduction of certain lifting (e.g. conveying and treating) costs. In these circumstances the net royalty payments are considered to be in the nature of a production cost or tax. As such the reported turnover should include all invoiced sales and the net royalty payments should be charged to cost of sales.

(b) In other arrangements the royalty holder has a more direct interest in the underlying production and may make lifting and sale arrangements independently. This is typical of many of the forms of royalty agreement common in the USA where accounting principles require that the value of production representing such royalty oil or gas be excluded from turnover (and, hence, cost of sales), other than in the accounts of the royalty owner (Rule 4-10 SEC Regulation SX). The OIAC concurs with this accounting treatment in such circumstances.

113. A company with a royalty interest in a property should record related income and expense in accordance with the underlying agreement. However, in the absence of specific contractual guidance, the company should record as turnover the gross value of the oil and gas royalty applicable to the period, whether receivable in kind or in cash. Any costs incurred or deducted before remittance of the royalty proceeds should be recorded within cost of sales.

Overlift and underlift

114. Lifting or offtake arrangements for oil and gas produced in jointly owned operations are frequently such that it is not practicable for each participant to receive or sell its precise share of the overall production during the period. Any resulting short term imbalance between cumulative production entitlement and cumulative sales attributable to each participant at a reporting date represents overlift or underlift.

115. Overlift represents an obligation to transfer future economic benefit (by foregoing the right to receive equivalent future production), and therefore constitutes a liability under FRS 5, whilst underlift represents a right to future economic benefit (through entitlement to receive equivalent future production) which constitutes an asset under FRS 5.

116. Where overlift or underlift balances are material, they should be reflected by adjusting cost of sales and working capital balances.

117. If adjustments are recorded at cost, increasing (for overlift) or decreasing (for underlift) cost of sales to mirror actual liftings, this has the effect of recognising gross profits on a liftings basis. If adjustments are recorded at market value, increasing (for overlift) or decreasing (for underlift) cost of sales, this has the effect of recognising gross profit on an entitlement basis.

118. In either instance turnover represents the actual invoiced value of liftings sold. Whilst it is also theoretically possible to effect the entitlement method by adjusting turnover, rather than cost of sales, at market values, the recommended principle is that turnover should reflect only invoiced sales and, hence, such an approach is inappropriate.

119. The substance of the business of an upstream company is the production of crude oil or gas. As such, the OIAC believes that profits should reflect production activity and it is inappropriate that they fluctuate because of the timing of individual liftings.

120. Consequently this statement recommends that the entitlement basis should be followed such that, where material, adjustments in respect of overlift or underlift should be recorded against cost of sales at market value. The equivalent balance sheet entry should be debited or credited to debtors or creditors respectively.

121. Market value in this context should be determined in relation to the market price prevailing at the balance sheet date.

Crude oil trading

122. In addition to selling their own oil production, companies often trade in crude oil cargoes of which they can either take delivery and sell the physical oil obtained, or the cargo can be re-sold without taking

delivery. The accounting issue is whether to record the transactions gross as turnover and cost of sales, or to record only the net profit or loss as turnover or other income.

123. In the view of the OIAC, crude oil trading and upstream operations are distinct segments of the business of an oil company. For most upstream businesses crude oil trading is incidental to their main purpose - the discovery and production of crude oil and gas. Consequently this statement recommends that crude oil trading activity by upstream businesses should normally be excluded from upstream segment turnover.

124. The net profit or loss on crude oil trading activity should be included within the 'other operating income' caption in the profit and loss account. The related gross sales and costs of crude oil trading activity so recorded should be shown within the notes to the accounts.

Production testing revenue

125. Onshore wells, in particular, are frequently placed on long-term production test as part of the process of appraisal and formulation of a field development plan.

126. The revenues from such production may be recorded either within turnover or credited against appraisal costs. The former approach has the advantage that turnover reflects actual production. However, it is generally extremely difficult to apportion related costs between those required for production (and hence chargeable to cost of sales) and those capitalisable as appraisal or development costs. There is therefore scope for misstatement of gross profits.

127. This statement recommends that revenues from test production of wells pending a development decision should be credited to turnover, but that an amount based on such revenues should be both charged to cost of sales and credited against appraisal costs so as to record zero net margin on such production.

Tariff income

128. Many oil and gas companies receive tariff income in connection with the use by others of shared facilities. This 'renting out' of assets may be an integral and significant part of a company's operations. Consequently such tariff income should be included within reported turnover and separately disclosed within segment information. Tariff income is distinguished from straightforward reimbursement without uplift of operating costs for shared facilities. Such cost recharges should be credited against operating expenses, not reported as turnover.

Gas sales contracts

129. The facilities and infrastructure required for the efficient and reliable production and marketing of natural gas are such that most gas developments are supported by complex gas sales contracts which specify offtake ranges and price adjustment mechanisms for many years ahead. Agreements in respect of gas from separate fields may also be linked if either field can physically supply the related offtake facilities.

130. The central accounting problem arises when an imbalance occurs either:

- between the actual and contracted volumes taken ('take or pay' or 'minimum throughput' arrangements), or

- between the actual and contracted volumes delivered by joint producers ('gas banking' arrangements)

The essence of the problem is whether, and at what value, to record such imbalances in the accounts. In principle it is similar to the question addressed above in connection with crude oil overlift and underlift, although the increased inflexibility and difficulty of marketing natural gas means that greater prudence is required in assumptions as to how imbalances are to be settled. In practice the physical and timescale aspects of such imbalances are frequently characterised by substantial uncertainties, so, notwithstanding the strict contractual position, assumptions may need to be made regarding:

- the marketability of future gas production;
- the reservoir behaviour and future deliverability of gas, particularly that associated with oil production;
- the price likely to be realised on future sales correcting any imbalance, particularly if this is likely to be lower than that prevailing when the imbalance arose.

131. The underlying principles which determine how each contract should be accounted for are set out in FRS 5. Whilst the particular facts and circumstances surrounding each contract need to be considered in determining the appropriate accounting treatment, the following general principles should be applied by producing companies to record the effect of such imbalances:

(a) Under a 'take or pay' contract a customer who is unable to take the minimum agreed offtake for a period may have to make an unconditional cash payment to the supplier as compensation for the shortfall. In such a situation the supplier should record a debtor at period-end and credit the proceeds to turnover.

(b) Alternatively, the customer may have the right to make good a shortfall in offtake for one period by increasing the offtake in subsequent periods by a corresponding amount. In this case the supplier should again record a debtor in the period of shortfall, but should credit a liability account until the 'make-up' gas has been delivered (or until it is clear that the customer will not be able to take the 'make-up' gas within the agreed period), when the credit balance will be released to the profit and loss account.

(c) If the supplier is unable to supply agreed quantities of gas, provision should be made for any contractual liabilities and penalties that may arise.

(d) In the case of gas banking arrangements, the company 'depositing' the gas should record an asset, represented by the obligation of the other supplier ('the banker') to repay 'banked' gas, but only when, and to the extent that, future sales of the 'banked' gas are reasonably assured. Such 'banked' gas should be recorded initially within stocks at the lower of production cost and net realisable value. These stocks should be charged to cost of sales as banked volumes are drawn down.

(e) In the case of the 'banker', a liability in respect of gas 'banked' by another supplier should be recorded immediately. The liability should initially be established at the current production cost and revised at least annually, to reflect any changes in production costs. If it becomes clear that, due to the contractual terms, the liability is unlikely to be settled, the balance can be credited to earnings.

RISK SHARING ARRANGEMENTS

Introduction

132. Arrangements involving the transfer or financing of all or part of an owner's interest in an oil and gas property in exchange for either cash or a commitment by the transferee or lender to fund or bear some or all of the future costs of exploration and development on behalf of the transferor occur frequently and vary widely. The range and variety of such transactions represent a continuum between simple sale and purchase agreements at one end and straightforward asset-backed borrowings at the other. Such transactions may represent either borrowings or current or future disposals (or some element of each) of licences, production or reserves. The precise economic effect of the transaction may not be immediately determinable because it may be dependent upon some uncertain future event.

133. Whilst each transaction is unique, many are commonly categorised by type according to one or more of the following general 'labels': joint arrangements (more commonly referred to as 'joint ventures' within the oil and gas industry – see paragraph 142), farm ins, carried interests, production sharing agreements, overriding royalties, net profits interests, forward sales, production loans and project finance.

134. The underlying principles which determine how each such arrangement should be accounted for are set out in the ASB's Financial Reporting Standards (FRSs), principally in FRS 5 and FRS 9 *Associates and Joint Ventures*. In view of the diversity of arrangements, even within each general category referred to in paragraph 132, the specific features of each arrangement must be considered, and the arrangement accounted for by applying the requirements of the relevant FRSs. The following paragraphs serve to facilitate the application of those standards to the more common forms of those arrangements.

135. The essential economic questions giving rise to accounting issues in connection with such transactions and arrangements may be summarised as:

(a) whether the rights and/or obligations attaching to an oil and gas interest have been or may be transferred and, if so, to what extent;

(b) whether the consideration can be accurately identified and valued;

(c) whether there is an obligation, or contingent obligation, to repay some or all of such consideration, either in cash or otherwise.

136. The answers to these questions will determine whether, or to what extent, a particular transaction or arrangement represents a sale, a conditional sale or a financing arrangement and whether the effect is current or in the future. This determination will, in turn, define the appropriate accounting treatment.

137. From the perspective of the owner or transferor, the principal accounting issues which follow such determination include:

(a) whether to record the transaction as a sale, conditional sale or as a financing arrangement;

(b) if it represents a sale or a conditional sale:

whether to record consideration as turnover or as proceeds of a fixed asset disposal and, if so, when;

how, when and to what extent to recognise any profit or loss on disposal;

(c) if it represents a financing arrangement, how, when and to what extent to recognise any repayment obligation.

138. From the perspective of the transferee or lender, the principal accounting issue is whether the payments made in connection with the arrangement are or may be recoverable from the owner and, if so,

under what circumstances and when. This will determine the classification of the asset acquired.

139. The general accounting principles which apply to such transactions are as follows:

(a) transactions in which funds exchanged are repayable at a predetermined monetary amount should be accounted for as borrowings;

(b) where the owner has a substantial obligation of uncertain amount for future performance in relation to an interest transferred, the recognition of a liability in accordance with FRS 5 or a provision in accordance with FRS 12 is likely to be such that recognition of any expected profit will be deferred until the obligation is met or the amount of the obligation can be assessed with reasonable certainty;

(c) where only part of an interest is transferred, no profit should be recognised unless recovery of the residual capitalised cost attributable to the retained interest is assured through the value of retained commercial reserves;

d) there should be no 'setting-off' in recording the effect of transactions on assets, liabilities, revenues and expenses, unless there is a contractual right and the requirements of FRS 5 are met.

The recommended application of these principles to various categories of specific transactions and arrangements is described below.

Consortia

140. The arrangements through which participants conduct oil and gas exploration and production operations on a joint basis rarely involve the establishment of a separate entity carrying on a trade of its own. The terms of the joint arrangement are generally set out in a 'joint operating agreement' such that all significant matters of operating and financial policy are predetermined. Under the joint operating agreement, the operator is elected to manage the assets and is generally empowered to enter into contracts and incur costs which are rechargeable to the other participants.

141. The specific features of each such joint arrangement should be considered and the arrangement accounted for according to the requirements of FRS 9 *Associates and Joint Ventures*. However, it is envisaged that the most common forms of such joint arrangements will fall within the definition of 'joint arrangements which are not entities', and not the FRS 9 definition of 'joint venture'. Paragraphs 143 to 146 apply only where this is the case.

142. Users of this statement should be aware that 'joint arrangements', as described in paragraph 140 and as defined in this statement, are more commonly referred to as 'joint ventures' within the oil and gas industry. However, FRS 9 uses the term 'joint venture' to describe a significantly different type of business structure. Therefore, in order to minimise the confusion which may arise from this difference in usage, this statement uses the term 'joint arrangement' to describe an oil and gas industry 'joint venture' and the term 'entity which is a joint venture as defined in FRS 9' to describe an FRS 9 'joint venture'.

143. Each participant should account for its proportionate share of the costs, revenues, assets and liabilities of the joint arrangement (Companies Act 1985 Schedule 4A, Paragraph 19(1), as amended by the Companies Act 1989 and FRS 9 paragraph 18).

144. The operator may have a direct legal liability to third party creditors in respect of the entire balance arising from transactions related to the joint arrangement and a similar entitlement in respect of debtors. In accordance with FRS 5, paragraph 29, such amounts are liabilities and assets of the operator and should not be offset against amounts recoverable from or payable to the other non-operator participants.

145. Each non-operating participant's entitlement or liability in respect of its share of the working capital balances relating to the joint arrangement should be analysed across the underlying elements of working capital such as stocks, debtors, cash and creditors, in order properly to classify and avoid setting off assets and liabilities.

146. The operator will not normally have the right to dispose of significant stocks held in relation to the joint arrangement without the agreement of the participants who will generally enjoy pre-emption rights. Hence it is appropriate for the operator to include only its net share of such stocks in its own accounts, the balance attributable to its fellow participants being applied against creditors due to the non-operator participants or added to debtors due from the non-operator participants.

147. Where participants conduct exploration and production activities indirectly through an entity which is a joint venture as defined in FRS 9, which itself holds the direct interest in the licences and reserves, the participants should account for their interests under the gross equity method in accordance with FRS 9. This will result in a different accounting treatment from that described above for 'typical' joint arrangements.

148. In certain circumstances, distinct from the arrangement described in paragraph 147 above, participants may set up an incorporated, jointly owned and controlled legal entity to act as operator but retain direct interests in the licence and reserves themselves as if they were non-operator participants in a joint arrangement. In such circumstances, the participants will account for their respective interests in the operator company under the gross equity method, but account for their interests in the licence and reserves as described in paragraphs 143 and 146 above.

Carried interests

149. A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a licence in which both own a portion of the working interest. This arises when the carried party is either unwilling to bear the risk of exploration or is unable to fund directly the cost of exploration or development. Owners may enter into carried interest arrangements with existing or incoming participants in a joint arrangement, at either the exploration or development stage, or both.

150. If the exploitation of the property is successful, then the carrying party will be reimbursed either (a) in cash out of proceeds of the share of production attributable to the carried party, or (b) by receiving a disproportionately high share of the production until the carried costs have been recovered. If the project is unsuccessful, then the carrying party will never be reimbursed for all or part of the costs that it has incurred on behalf of the owner.

151. Generally, exploration carried-interest arrangements involve the de facto disposal of exploration risks (and rewards) by the carried party. If the significant benefits and risks relating to a working interest are considered to have been transferred, the carrying party should normally capitalise or expense the costs borne on behalf of the carried party in accordance with its normal accounting policy. The carried party should not make any adjustments in respect of the arrangements.

152. There are many different types of development carried interest arrangements that arise in practice. Each arrangement tends to be unique and requires careful analysis in order to determine the substance of the arrangement. The examination should take into account the position of both parties to the arrangement, together with their apparent expectations and motives for agreeing to its terms. It should identify the extent to which the carried party has transferred the benefits relating to the carried interest and the risks inherent in those benefits (e.g. adverse price movements, political risk, reserve risk and development risk).

153. Development carry arrangements may be, in substance, financings, disposals or partial disposals when viewed from the perspective of the carried party. If the risks associated with the development are not significant and the carrying party is relatively assured of a lender's return (either by retaining the carried party's share of production proceeds, through an increased share of production or through the payment of cash by the carrying party), the substance of the carry arrangement would generally appear to be a financing.

154. If the facts and circumstances suggest that the nature of the arrangement is essentially a financing (e.g. there is a high probability of success, the terms of the carry arrangement require reimbursement of costs borne on behalf of the carried party with interest and there is no material premium to be paid at the end of the carrying period), the carrying party should normally record a debtor for costs that may subsequently become reimbursable by the carried party. If the project is successful and the amounts received from the carried party exceed the debtor balance, the excess should be credited to the profit and loss account to offset the additional interest costs that were borne or to compensate for the reduction in interest income over the period of the carry.

155. By contrast, in some development carry arrangements, the risks and potential benefits transferred to the carrying party are significantly greater than is usually the case in a financing transaction. Typically, such cases would involve the carrying party receiving, or having the potential to receive, significantly more than a lender's rate of return in consideration for the assumption of risks additional to those that a lender would typically accept. In such case, the substance of the transaction would appear to be that the carrying party has in effect acquired oil and gas reserves. In such circumstances, the carrying party should account for the costs borne on behalf of the carried party as its own. The carried party should account for the arrangement as a disposal in accordance with its normal accounting policy.

156. A variation of the case arises when 'sole risk' drilling has taken place. Once the results of the sole risk drilling are known, the 'non-sole risk parties' have the right to participate in the discovery by reimbursing the 'sole risk party' (the carrying party) with their share of the costs incurred by paying a substantial premium. Such an arrangement should be accounted for by the parties in the manner described in paragraphs 151 to 155.

Production sharing agreements

157. Production sharing contracts (PSCs) are generally between oil companies and the governments (or national oil companies) of oil producing countries. Typically, the contractor (the oil company or group of oil companies) agrees to pay and bear the risk of all exploration, development and production costs, in respect of the contract area. If there is production, the contractor receives a share of the production for recovery of its costs ('cost oil'). The remainder of the production ('profit oil') is shared between the contractor and the government in agreed ratios, the share of the profit oil taken by the government representing a form of taxation.

158. In some PSCs the government (or national oil company) not only receives a share of production as a form of taxation but will also be a participant. As participant it will pay its share of costs (or be carried by the other participants) and will receive its participant share of cost oil and profit oil. Each arrangement tends to be unique and requires careful analysis in order to determine the most appropriate way to account for any carried interest (see paragraphs 149 to 156 above).

159. Whilst production sharing agreements vary, typically they will fall within the FRS 9 definition of 'joint arrangements which are not entities'. Therefore, in accordance with paragraph 18 of FRS 9, the parties to the production sharing agreement should account for their own assets, liabilities and cash flows, measured in accordance with the terms of the production sharing agreement. However, the accounting treatment of the assets, liabilities and cash flows arising under the production sharing agreement should reflect the agreement's commercial effect (FRS 5 paragraph 1) and not its structure or the terminology within it.

160. The commercial effect is generally that the contractor enters into such arrangements not as a 'banker' but primarily to gain access to additional future production. If there are any carried costs under the PSC terms, they would form an integral part of the overall project investment. Similarly, the contractor's anticipated production revenues, from both the "cost oil" and the "profit oil" elements, are combined in their evaluation of the project economics. It follows that the reporting company, in accounting for the PSC transactions, would draw no distinction between the costs attributable to its own share of production and those attributable to the share taken by the government.

161. The following principles may therefore be appropriate in accounting for production sharing contracts:
   (a) The oil company's turnover and cost of sales should include revenues and operating costs associated with the oil company's interest including any cost oil and the government interest as appropriate.

   (b) Unit-of-production calculations should include the expenditures and oil and gas reserves and production associated with the company's interest including any cost oil. Capitalised costs related to any carry of the government interest should be amortised over the life of the field as a whole, rather than just over the period during which "cost oil" reimbursement occurs.

Production loans, forward sales and other similar arrangements

162. There is a variety of forms of transaction which involve the advance of funds to the owner of an interest in an oil and gas property in exchange for the right to receive the cash proceeds of production, or the production itself, arising from the future operation of the property. The lender's rights of recourse may be limited to a specified property or they may extend to the owner's other properties. In such transactions the owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Whether the transaction represents a sale or financing, contingent or otherwise, rests on the particular circumstances of each case, to be determined in accordance with FRS 5 and the following supplementary guidance.

163. If the risks associated with future production, particularly those related to ultimate recovery and price, remain primarily with the owner, the transaction should be accounted for as a financing. In such circumstances the repayment obligation will normally be defined in terms of cash or cash equivalent (as in a production loan) and a liability should be recorded equivalent to the amount of advances received by the owner. The lender should record its asset as a debtor.

164. If the risks associated with future production, particularly those related to ultimate recovery and price, rest primarily with the 'purchaser', the transaction should be accounted for either as a conditional sale or as a disposal of fixed assets. In these circumstances the following principles are recommended:

   (a) Where the owner's obligation is defined in terms of a specified QUANTITY, rather than value, of future production (as in a forward sale), recognition by the owner of any expected gain arising should be deferred until the related production or delivery has occurred. An amount equivalent to the advances received by the owner should be recorded as a liability and released to the profit and loss account as the performance obligation is met. The 'purchaser' should normally record the cost of its interest in the future production as 'stock', with disclosure in a note to the accounts of any amounts which are not expected to be produced or delivered within one year of the balance sheet date. If production is inadequate to meet the sale commitment, the owner will have to make good the shortfall from alternative sources; any losses that may result should be provided for as soon as they become apparent.

   (b) In certain circumstances, where the 'purchaser' is entitled to a specific PROPORTION of future production (such as a royalty interest), rather than a specified quantity of such production, the transaction should be categorised by the original owner as the disposal or partial disposal of a fixed asset. In this case, the production risk is borne by the 'purchaser', and the original owner should record the proceeds received, after making provision for any future costs to be incurred. The 'purchaser' should record the advances made as a fixed asset to be amortised on a unit-of-production basis.

   (c) A third category of transaction may also be distinguished in which the purchaser's entitlement is represented by a specific proportion of future net revenue (such as in a net profits interest). Typically the 'owner' is responsible for selling the production, and after deducting such costs as are defined in the agreement, remitting the proceeds to the purchaser. The variety of such arrangements is wide and in each instance the accounting treatment applied to the transaction creating the interest will need to reflect the specific contract terms and the intentions and status of the parties. However, as a general principle, the OIAC considers that in such circumstances the 'owner' retains the primary interest in the underlying reserves. Therefore the owner should account for the advances received in the same manner as set out in paragraph 164 (a) above. The 'purchaser', however, should classify the advances made as a fixed asset investment, rather than as a tangible fixed asset, as it is not considered to hold a direct interest in the underlying reserves. The balance on this fixed asset investment account should, nevertheless, be amortised on a unit-of-production basis.

(d) Oil and gas reserve disclosures in accordance with this statement should follow the accounting treatment applied. A company should report its interest in oil and gas reserves only where the related costs are recorded within tangible fixed assets.

Project finance

165. Particular accounting and disclosure issues arise in respect of limited or non-recourse financing arrangements, frequently described as 'project finance', where the timing and amount of repayment are critically dependent on the future production profile and revenues from a specific property.

(a) Whilst it is theoretically arguable that the owner's retained interest in the property is, in substance, the surplus of the net present value of the future project revenues over the liability to repay the non-recourse finance and related interest, such reasoning would suggest that the liability be credited directly against the owner's related capitalised project costs. Such 'setting off' is contrary to the accounting principles set out in the Companies Act 1985 and FRS 5 paragraph 29. Furthermore, these arrangements will not generally qualify for linked presentation under the requirements of FRS 5 paragraphs 26 to 28. Hence limited or non-recourse project finance arrangements should generally be accounted for in accordance with paragraph 163 above, recording the asset and liability separately.

(b) The Companies Act 1985 (Schedule 4, Paragraph 48) also imposes an obligation to analyse borrowings according to the timing of future repayments. Where the repayment schedule is a function of estimates of future production, future prices and, possibly, future costs it is generally not possible to determine in advance the precise amounts to be repaid in each future year. In such circumstances a general indication of the assumptions made as regards production, prices and costs applied in estimating the repayment schedule should also be given.

c) Where applicable, as required by FRS 4 paragraph 63, a brief description should be given of the legal nature of any instrument included in debt where it is different from that normally associated with debt, for example where the debt is subordinated or where the obligation to repay is conditional. Where amounts are included in debt that represent instruments in respect of which the amount payable, or the claim that would arise on a winding up, is significantly different from that at which the instrument is stated in the financial statements, that amount should be stated. This information may be summarised and need not be given for each individual instrument.

Tariffed and shared assets

166. As the industry's infrastructure continues to expand there is an increasing incidence of contractual arrangements for the joint use of assets. Platform, processing, pipeline or terminal facilities initially or primarily established for one venture may have surplus capacity which is made available to other ventures under tariffing or cost-sharing agreements. Such arrangements may significantly extend the effective economic life of such facilities from the perspective of the owners. There is, therefore, a question as to the depreciation rates to be applied under the unit-of-production method.

167. A tariffing or cost-sharing arrangement may extend the economic life of the owner's own reserves by defraying part of the operating costs and hence delaying the point at which its own field becomes uneconomic. This impact will normally be reflected through an increase in the owner's reserves included in the depreciation calculation.

168. It is less obvious as to how to determine the adjustment to the depreciation rate appropriate to reflect the additional third party reserves to be catered for as a direct result of the tariff or cost sharing contract. There are four main options:

(a) To ignore the third party throughput altogether.

(b) To reflect the third party throughput in both the production figure and the reserve base only as it is produced.

(c) To reflect the third party throughput and its reserves projected to be produced under the committed period covered by the tariff or cost-sharing arrangement.

(d) To reflect the third party throughput and its total estimated reserves in the fields currently covered by the tariff or cost-sharing arrangement.

169. This statement recommends that the third of these options should be applied, provided that there is a reasonable expectation of fulfilment by the third party of the volumes covered by the contract. No account should be taken in unit-of-production calculations of third party reserves which are not contractually committed to flow through the owner's facilities.

170. Disclosure should be made of the nature and existence of tariff or cost-sharing arrangements, and of the fact that (but not the amount of) additional third party reserves have been taken into account in the unit-of-production calculations for depreciation and decommissioning provisions.

DISPOSALS, ACQUISITIONS AND OTHER CHANGES OF INTERESTS

Disposal of interests

Full cost companies

171. Proceeds from the full or partial disposal of a property should be credited to the relevant cost pool.

172. Proceeds from the disposal of part or all of an interest which is held outside a cost pool should be credited initially to that interest with any excess being credited to the profit and loss account.

Successful efforts companies

173. Proceeds from the full or partial disposal of a property where commercial reserves have not been established should be credited to the relevant cost centre. Only if there is a surplus in the cost centre should any of the proceeds be credited to income.

174. A gain or loss on disposal of an interest in a field where commercial reserves have been established should be recognised to the extent that the net proceeds exceed or are less than the appropriate portion of the net capitalised costs of the field or property

Unitisations and redeterminations

175. In a 'unitisation', licensees of oil or gas reserves pool their individual interests in return for an interest in the overall unit, which is then operated jointly to increase efficiency. The unitised area is generally restricted to the defined reservoir. Therefore, it rarely covers an entire licensed area and it may also be restricted vertically, embracing only certain specific horizons.

176. Once an area is 'unitised', licensees will share costs and production in accordance with their percentages established under the unit agreement. Costs and production associated with non-unitised areas within the original licences will continue to fall to the original licensees.

177. Initial percentage interests in the unit are generally based on estimates of relative quantities of reserves attributable to each contributor to the unit. The percentages allocated may also reflect relative contributions to exploration costs incurred to discover and define the reservoir as well as the relative economics of development of various sectors of the reservoir.

178. This 'initial determination' is frequently based on very limited data about the reservoir. As a result, agreements usually provide for one or more 'redeterminations' of percentage interests once better reservoir data becomes available. Generally, the revised percentage interests established at a redetermination are effective from the date of the original unitisation. Consequently, adjustments are required amongst the unit members in respect of their relative entitlements to cumulative production and for their shares of cumulative costs.

179. Unit agreements generally set out in detail the way in which such adjustments should be effected and the time period allowed for the re-establishment of equity as between the participants.

180. Adjustments are generally effected as follows:

(a) Adjustments in respect of cumulative 'capital' costs are usually made immediately following the redetermination by means of a lump sum reimbursement, sometimes including an 'interest' or uplift element to reflect related financing costs.

(b) Adjustments to shares of cumulative production are generally effected prospectively. Participants with an increased share are entitled to additional 'make-up' production until the cumulative liftings are rebalanced. During this period adjusted percentage interests are applied to both production entitlement and operating costs. Once equity is achieved the effective percentage interests revert to those established by the redetermination. The 'make-up' period may range from a few weeks or months to several years.

181. The principal considerations in making these arrangements are to ensure that cumulative equity liftings are rebalanced as quickly as possible without curtailing too drastically the operating cash flows of those parties whose working interests are reduced.

182. These arrangements give rise to a number of accounting issues:

(a) Whether the redetermination adjustments should be accounted for as a prior period restatement, currently or over the period required by the agreement to re-balance cumulative production.

(b) How to account for any capital costs reimbursed.

(c) How to account for any 'interest' or 'uplift' reimbursed in conjunction with any capital cost adjustment.

(d) How to account for revised shares of decommissioning liabilities

183. OIAC recognises that the unitisation agreement will generally be designed with the objective of allocating production over the life of the field on the basis of the reserves ultimately attributed to the licence interests originally pooled on unitisation. However, because of variations in oil and gas prices and unit production costs over a field's life, the make up period will not necessarily restore each participant's economic position to that which would have arisen had the redetermined interests been applied from inception. Rather, unitisation constitutes an agreement by each party to forego a direct interest held in the reserves of their licence area for an interest in the cash flows and future production to be determined in accordance with the unitisation agreement. It is therefore OIAC's view that the redetermination constitutes agreement on a change in the basis on which costs and production will be shared after the redetermination rather than a correction of an historical 'error' in the allocation of production from the unitised field. Consequently the effects of a redetermination should generally be recognised as the adjusted production entitlements and expenditures occur or fall due.

184. In performing an impairment test in accordance with this statement, all of the expected effects of a future redetermination should be taken into account on a best estimate basis, whether or not the redetermination has been agreed, including reimbursement of capital costs.

185. Make-up oil or gas should generally be accounted for in the period in which it is produced. Where the make-up period extends beyond the end of the period in which a redetermination is finalised, no accrual should be recorded in respect of estimated net revenues attributable to the balance of make-up production due in future periods.

186. Lump sum 'capital' reimbursements due should be accounted for immediately upon agreement of the redetermination consistently with the capitalisation policies applied in respect of the underlying elements of such costs for the original interest in the unit. Unit-of-production calculations should be adjusted from the date of redetermination to reflect the revised allocation of costs, liabilities, production and reserves. Reimbursements of operating costs should also be matched with the related changes in production.

187. Any 'interest' or 'uplift' paid or received in conjunction with reimbursement of 'capital' costs should be accounted for consistently with the company's established accounting policies for fixed assets and interest expense or income.

188. Revised proportions of future decommissioning obligations should be accounted for immediately upon agreement of the redetermination, with a corresponding adjustment to the related 'decommissioning asset'.

189. In rare circumstances it is possible that the redetermination may be so significant, or late in the field's life, that there is a risk that equity rebalancing cannot be completed before decommissioning. The provisions of the unit agreement in relation to ultimate settlement, if any, of the balance of make-up oil remaining at decommissioning, will determine the related accounting treatment. If the agreement provides that there should be a financial settlement in such circumstances, then this should be recorded appropriately by all parties as soon as the amounts involved can be determined with reasonable certainty.

190. The effect of a redetermination of a company's interest in an oil or gas field should be reflected in its accounts only when the revised percentage interests have been agreed by all participants. Where there is substantial agreement on the proposed revision, a company should disclose the expected effect of the redetermination. Where, at a reporting date, adjustments in respect of a redetermination have not been completed, disclosure should be made of the outstanding quantities or amounts and the expected period required to complete the adjustment. Reserve quantity disclosures should be adjusted to reflect future entitlements after taking account of make-up production.

Farm ins

191. A farm in typically involves the transfer of part of an oil and gas interest in consideration for an agreement by the transferee ('farmee') to meet, absolutely, certain expenditure which would otherwise have to be undertaken by the owner ('farmor').

192. In such circumstances the transfer should be accounted for as follows:

(a) the farmor should not record, in its financial statements, any expenditure made 'on its behalf' by the farmee;

(b) any capitalised costs previously incurred by the farmor in relation to the whole interest should be redesignated as relating to the partial interest retained;

(c) where the transaction includes an element of cash consideration (such as through the reimbursement of past costs) the farmor should credit any proceeds to the accounts, whether capital or expense, in which such costs were initially recorded. Any cash received in excess of related unamortised past costs should be accounted for as excess disposal proceeds in accordance with this statement;

(d) the farmee should record all of its expenditure pursuant to the arrangement, both in respect of its own interest and that retained by the farmor, as and when the costs are incurred. The expenditure should be capitalised or expensed in accordance with the principles recommended elsewhere in this statement;

(e) where the consideration for the farm in includes an arrangement for the farmee to bear subsequent costs which would otherwise fall to the retained interest of the farmor, the farmor should disclose the amount of such expenditure incurred by farmees in aggregate during the accounting period to provide an indication of the consideration received for the farmouts;

(f) no similar disclosure is required by farmees, since expenditure incurred on licence interests will already be disclosed in their accounts in accordance with this statement.

FINANCIAL STATEMENT PRESENTATION AND DISCLOSURES

Accounting policies

193. The methods of accounting for oil and gas activities should be disclosed. These disclosures should normally include policies in respect of:

(a) accounting for pre-production costs;

(b) amortisation of capitalised costs;

(c) impairment tests;

(d) future decommissioning costs;

(e) deferred taxation;

(f) turnover and royalties;

(g) interest.

194. The method adopted in respect of pre-production costs should be described in sufficient detail to make clear the precise nature of costs, including exchange gains and losses and interest, capitalised or written off and the cost centres adopted. In particular, whether full cost or successful efforts accounting policies have been adopted should be specifically disclosed.

195. Where unit-of-production methods are used in calculating charges for depreciation, depletion and amortisation or taxation, the reserve categories (proved, probable or possible) and proportions of each category used should be given together with a description of the related cost centres. Similar information should be provided in respect of impairment tests.

196. The method of reflecting changes in estimates should also be disclosed.

197. In relation to deferred taxation, details should be provided explaining the treatment of each of the significant timing or permanent differences.

198. The treatment of royalties in arriving at reported turnover and oil and gas reserves should be disclosed.

199. Uniform group accounting policies should be used for determining the amounts to be reported in a company’s consolidated accounts, if necessary by adjusting for consolidation the amounts which have been reported by subsidiary undertakings in their own accounts. For example, a company’s consolidated accounts should reflect a consistent definition of commercial reserves and a consistent application of either full cost or successful efforts accounting policies throughout all of the group’s interests, irrespective of the accounting policies of the group company which holds those interests.

Capitalised costs

200. The aggregate capitalised costs relating to a company’s oil and gas exploration and production activities and the related depreciation, depletion and amortisation should be disclosed as at the balance sheet date.

201. This disclosure should distinguish capitalised costs, where appropriate, between costs held pending determination and other capitalised costs and should be further analysed by geographical area.

202. If the company’s consolidated accounts include investments that are accounted for by the equity method or the gross equity method, the company’s share of the net capitalised costs relating to oil and gas exploration and production activities of associates and entities which are joint ventures as defined in FRS 9 as at the end of the year should be separately disclosed.

Decommissioning

203. Provisions for decommissioning costs should be separately disclosed under the balance sheet caption 'provisions for liabilities and charges'.

204. Particulars regarding the decommissioning obligation and the assumptions adopted in relation to the measurement of the decommissioning provision should be disclosed in the notes to the accounts, as required by FRS 12.

Pre-production costs incurred or provided

205. Each of the following types of costs, whether capitalised or written off, incurred during the accounting period should be disclosed in total and by geographical area:

(a) Licence or concession acquisition costs;

(b) Exploration and appraisal costs;

(c) Development costs.

206. If significant costs have been incurred to acquire interests that have proved reserves, those costs should be disclosed separately from the costs of acquiring unproved properties.

207. Capitalised interest incurred on borrowings identifiable with specific oil and gas developments should be included under development costs in this analysis.

208. Disclosure should be made of that proportion of the total of pre-production costs incurred in the accounting period which has been capitalised.

209. The aggregate net book value of decommissioning costs capitalised at the period end should be disclosed separately.

210. If the company's consolidated accounts include investments that are accounted for by the equity method or the gross equity method, the company's share of the aggregate costs of property acquisition, exploration and development of associates and entities which are joint ventures as defined in FRS 9, whether capitalised or written off, incurred during the year should be separately disclosed in total and by geographical area.

Results of operations

211. The results of operations of oil and gas exploration and production activities should be disclosed in total and by geographical area. The analysis of results should be consistent with the primary profit and loss account format adopted by the reporting company but should distinguish between the following captions:

(a) turnover;

(b) production costs;

(c) exploration and appraisal costs;

(d) depreciation, depletion and amortisation provisions;

(e) allocable taxes;

(f) results of operations from oil and gas exploration and production activities.

212. For the purposes of this disclosure, overheads should be allocated by activity and geographical area. Corporate overheads and finance costs which cannot reasonably be allocated to oil and gas exploration and production activities should be excluded.

213. If the company's consolidated accounts include investments accounted for by the equity method or the gross equity method, the results of operations for oil and gas exploration and production activities of associates and entities which are joint ventures as defined in FRS 9 should not be shown as part of the company's results of such operations. However the company's share of the results of operations for oil and gas exploration and production activities of those

companies for the year should be separately disclosed in total and by geographical area. In the case of entities which are joint ventures as defined in FRS 9 accounted for under the gross equity method this disclosure will be incremental to the presentation and disclosure of certain items on the face of the profit and loss account and in the notes, as is required by FRS 9.

Results of acquired operations

214. Acquisitions are defined as '*operations of the reporting entity that are acquired in the period*' (FRS 3, paragraph 3). This definition is broader than that for discontinuances. Accordingly, an operation reported as an acquisition may be smaller in scale than a comparable discontinuance and would encompass the acquisition of a share or further share of an interest in a field or asset already partly owned. On this basis, for example, even a farm-in to a licence would constitute an acquisition.

215. Where an operation is acquired, for example an interest in a producing field or a tariffed pipeline, the results of the operation should be disclosed down to the operating profit level in accordance with FRS 3. These results should include associated general and administrative expenditure.

216. On balance, the attributes and nature of an upward redetermination are so similar to those of an acquisition that it is considered that such redeterminations should be treated as acquisitions for FRS 3 reporting purposes.

217. Where an entity reports petroleum taxes, for example PRT, as an operating cost, consideration should be given to the impact of an acquisition on these taxes in determining the materiality of the acquisition for FRS 3 reporting purposes. The tax effect of the acquisition should be determined by computing petroleum taxes as if the acquisition had not taken place and comparing this notional tax charge with the actual tax charge for the period. The difference between these two computations is the petroleum tax effect of the acquisition.

<u>Full cost companies</u>

218. It is possible that a pre-producing operation acquired by a full cost entity may have no impact on the entity's profit and loss account other than on its depreciation charge (for example, a field under development). In such cases in determining the materiality of an acquisition for FRS 3 purposes, consideration should be given, inter alia, to the effect of any acquisition on the entity's depreciation charge.

219. The entity's depreciation charge for the period should be calculated in accordance with this statement including and excluding the acquisition. The difference between these two computations should be reported as the depreciation attributable to the acquisition.

<u>Successful efforts companies</u>

220. Where a successful efforts entity acquires an additional interest in a field or asset already partly owned, the portion of the entity's depreciation charge attributable to the operation acquired should be computed and reported on the basis set out in paragraph 215 above.

Results of discontinued operations

221. To be reported as a discontinued operation under FRS 3, a sale or termination must satisfy a number of specific conditions (FRS 3, paragraph 4 refers). In particular, 'the sale or termination must:

> *[have] a material effect on the nature and focus of the reporting entity's operations; and*
>
> *represent a material reduction in [the reporting entity's] operating facilities resulting either from:*
>
> - *its withdrawal from a particular market (whether class of business or geographical); or*
> - *a material reduction in turnover in the reporting entity's continuing markets; [and]*

[have] assets, liabilities, results of operations and activities [which] are clearly distinguishable, physically, operationally and for financial reporting purposes' (FRS 3, paragraphs 4c and d).

222. This definition is extended in the 'Explanation' of FRS 3 - '*To be classified as discontinued a sale or termination should have resulted from a strategic decision by the reporting entity either to withdraw from a particular market ... or to curtail materially its presence in a continuing market (ie 'downsizing')*' (FRS 3, paragraph 43).

223. An event or transaction may only be reported as a discontinuance where all the conditions set out in paragraphs 217 and 218 above are satisfied. For example, it is unlikely that a disposal of part of a share or interest in a field or other asset would be classified as a discontinuance. However, as detailed in paragraph 232 below, the profit or loss on the sale or termination of *an operation* may be reported in a reporting entity's profit and loss account after operating profit and before interest. Such *an operation* is not limited to the conditions set out in paragraphs 217 and 218 above.

224. Income and costs directly related to discontinued operations should be disclosed down to the operating profit level in accordance with FRS 3. These results should only include associated general and administrative expenditure to the extent that such costs will not arise in the future.

225. Lack of success in exploration and consequent cessation in a particular area is part of continuing operations and does not constitute an event of discontinuance. It is unlikely that the termination of exploration activity would be treated as a discontinuance unless a reporting entity permanently terminates such activities (or disposes of such interests) in all geographical areas or in an area which is so significant that the termination or disposal has a material effect on the nature and focus of the reporting entity's operations. Only in these circumstances should exploration expense be reported in the profit and loss account as a discontinuance.

226. A key issue arising in the separate disclosure of results for discontinued operations is the determination of the impact of the event on the reporting entity's depreciation charge. In making the necessary disclosures under FRS 3, the depreciation charge should be calculated in accordance with this statement including and excluding the discontinuance. The difference between these two computations should be reported as the depreciation attributable to the discontinuance.

227. In a business which involves the continual replacement of depleting assets, decommissioning is part of continuing operations and the event of decommissioning, of itself, does not constitute an event of discontinuance.

228. Downward redeterminations should be reported as part of continuing operations. A redetermination cannot constitute an event of discontinuance as it does not result '*from a strategic decision by the reporting entity*' (FRS 3, paragraph 43 refers) and does not represent a change in the nature and focus of the reporting entity's operations.

229. FRS 3 provides further clarification concerning discontinuance, stating that '*the regular sales and replacements of material assets which are undertaken by a reporting entity as part of the routine maintenance of its portfolio of assets should not be classified as discontinuances or acquisitions*' (FRS 3, paragraph 42).

230. If a disposal satisfies the specific conditions for being reported as a discontinued operation then the disposal cannot be considered to be part of routine *asset portfolio maintenance*.

231. An acquisition undertaken to replace depleting assets does not constitute *routine asset portfolio* maintenance. An example of *routine asset portfolio maintenance* would be the exchange of oil assets in the UK sector of the North Sea for oil assets in the same sector.

232. In the circumstances of an asset swap, the asset disposed of should be classified as a discontinuance when the conditions specified in FRS 3, paragraphs 4 and 43 are satisfied.

Full cost companies

233. The reporting of discontinuances by an entity adopting the principles of full cost accounting should be based, in the first instance, on the cost pools which the entity has established. Generally, the sale or termination of the whole of an entity's activities or interests in a particular cost pool (or of the majority of such interests to the extent that the residual interests are transferred to another pool) would constitute a discontinuance. However, a sale or termination material to a particular cost pool may not be material to the reporting entity as a whole, in which case it would not be classified as a discontinuance but any profit or loss on the sale or termination could be reported after operating profit and before interest in accordance with paragraph 236 below.

234. Any gain on disposal recognised in accordance with paragraphs 171 to 174 of this statement should be reported as part of results from continuing operations as an exceptional profit on the disposal of a fixed asset unless the sale or termination meets the requirements for classification as a discontinuance.

235. A related issue is that of the effect of discontinuance on an impairment test. Where a write-down of a cost pool is required as a consequence of a discontinuance (that is, after the disposal proceeds have been credited to the cost pool), the write-down should be reported as attributable to discontinued operations. This approach reflects the fact that the disposal proceeds are effectively lower than the carrying value of the assets disposed of and that a loss on disposal has thus arisen. However, the assessment of the need for such a write-down must be made by undertaking an impairment test as at the date of the discontinuance. Any impairment test undertaken at a later date, for example at the reporting entity's financial year end, should be dealt with in accordance with paragraph 236 below.

Exceptional items

236. FRS 3 sets out very specific requirements concerning the disclosure of transactions or events which constitute exceptional items (FRS 3, paragraphs 19, 20, 46 and 47 refer). All exceptional items should be included in the statutory headings to which they relate and be disclosed separately in a note, or on the face of the profit and loss account if necessary in order to give a true and fair view, other than the following which should be shown on the face of the profit and loss account after operating profit and before interest:

> '*profits or losses on the sale or termination of an operation;*
>
> *costs of a fundamental reorganisation or restructuring having a material effect on the nature and focus of the reporting entity's operations; and*
>
> *profits or losses on the disposal of fixed assets*' (FRS 3, paragraph 20).

237. If an asset write-down resulting from an impairment test is sufficiently material, it may be disclosed as an exceptional item, but within the

appropriate note to the accounts. Only if the write-down is so material that its disclosure on the face of the profit and loss account is required to give a true and fair view should such a write-down be so shown under the appropriate statutory heading of cost of sales or, in the case of exploration cost write-offs, other operating expenses.

238. Any difference between decommissioning costs incurred and previously provided for should be dealt with under cost of sales or other operating expenses. Only if this difference is sufficiently material should consideration be given to its disclosure as an exceptional item shown under cost of sales or other operating expenses.

239. A redetermination could have a material effect on a reporting entity's turnover and cost of sales. Where a redetermination causes a sufficiently material increase in turnover and cost of sales, it should be reported as an acquisition (paragraph 216 above refers). Where a redetermination causes a significant decrease in turnover and cost of sales, its effects should be recorded as exceptional items within the appropriate statutory headings. As indicated in paragraph 228 above, a redetermination cannot constitute an event of discontinuance.

Analysis of tax charge

240. FRS 3 requires that '*any special circumstances that affect the overall tax charge or credit for the period, or that may affect those of future periods, should be disclosed by way of note to the profit and loss account and their individual effects quantified*' (FRS 3, paragraph 23).

241. The reporting of *special circumstances* under FRS 3 is broader than simply determining the effects of acquisitions, discontinuances or exceptional items on a reporting entity's tax charge.

242. The guidance in paragraph 243 below applies to petroleum taxes wherever they are classified in an entity's profit and loss account and whatever the entity's policy for accounting for such taxes.

243. For petroleum taxes (such as PRT) which are levied on a field-by-field basis, *special circumstances* that may affect the overall tax charge or credit in a period, or in respect of future periods, will generally be items not directly related to the taxable unit. Such non-field items may include, but are not limited to:

exploration and appraisal expenditure reliefs (whether claimed or pending claim);
cross field allowances;
abandoned field losses reliefs.

Foreign exchange

244. The requirements of FRS 3 concerning the presentation of a statement of total recognised gains and losses (FRS 3, paragraphs 27 and 56 to 58) include the separate reporting and disclosure of foreign exchange movements.

245. For entities with oil and gas exploration and production activities, foreign exchange movements may, in certain circumstances, generate an unrealised foreign exchange deficit or surplus to be reported as a recognised loss or gain, whilst the underlying value of the entity which is producing a commodity denominated in United States dollars is increasing or decreasing respectively. This situation will benefit from further narrative explanation in the reporting entity's financial statements.

Commercial reserve quantities

246. The net quantities of a company's interest in commercial reserves of crude oil (including condensate and natural gas liquids) and natural gas should be reported as at the beginning and end of each accounting period in total and by geographical area. Such disclosures should be consistent with the quantities of reserves used in unit-of-production accounting calculations and should be presented as a separate unaudited statement.

247. Net quantities of reserves include those relating to the company's operating and non-operating interests in properties. Net quantities should not include reserves relating to interests of others in properties owned by the company, nor quantities available under long-term supply agreements. Net quantities should only include amounts that may be taken by Governments as royalties-in-kind where it is the company's policy (see paragraph 198) to record as turnover the value of production taken as royalty-in-kind.

248. Although the determination of the reserve quantities disclosed will be the responsibility of the directors, the source of the estimates should be disclosed together with a description of the basis used to arrive at net quantities.

249. Changes in the net quantities of reserves of oil and gas during each accounting period should be reported. Changes resulting from each of the following should be shown separately, with supporting narrative explanation of significant changes:

(a) Revisions of previous estimates - revisions represent changes in previous estimates of commercial reserves either upward or downward resulting from new information (except for an increase in proved acreage) normally obtained from development drilling or production history or resulting from change in economic factors or the application of improved recovery techniques.

(b) Purchases of reserves-in-place.

(c) Extensions, discoveries and other additions - additions to commercial reserves that result from:

(i) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery; and

(ii) discovery of new fields with commercial reserves or new reservoirs of commercial reserves in old fields.

(d) Sales of reserves-in-place.

(e) Production.

Supporting narrative explanation should be provided to describe the effect of significant unusual events e.g. redeterminations of equity interests in unitised fields which would be included within captions (b) or (d).

250. In determining the reserve quantities to be disclosed:

(a) if the company issues consolidated accounts, 100% of the net reserve quantities attributable to the parent company and 100% of the net reserve quantities attributable to its consolidated subsidiaries (whether or not wholly-owned) should be included. If a significant portion of those reserve quantities at the end of the year is attributable to one or more consolidated subsidiaries in which there is a significant minority interest that fact and the approximate portion should be disclosed.

(b) if the company's consolidated accounts include investments that are accounted for by the equity method or the gross equity method, those companies' net oil and gas reserves should not be included in the disclosures of the company's reserves. However, the company's share of those companies' net commercial reserve quantities as at the end of the year should be shown separately.

251. In reporting reserve quantities, reserves of oil and natural gas liquids should be stated in barrels and gas reserves in cubic feet.

Presentation formats

252. The appendices to this statement illustrate suggested formats for the presentation of certain of the disclosures recommended. In the interests of standardisation and comparability the adoption of these formats is encouraged.

Appendix 1 – Capitalised Costs

Capitalised Costs Relating to Oil and Gas Exploration and Production Activities at 31 December xxxx

	Total	Area A	Area B
Gross Capitalised Costs:			
- proved properties	£ x	£ x	£ x
- unproved properties	x	x	x
	x	x	x
Accumulated depreciation, depletion and amortisation	x	x	x
Net capitalised costs	£ x	£ x	£ x
Company's share of net capitalised costs of associates and joint ventures	£ x	£ x	£ x

Appendix 2 - Pre-Production Costs Incurred or Provided

Pre-Production Costs Incurred or Provided in Oil and Gas Exploration and Production Activities for the year ended 31 December xxxx

	Total	Area A	Area B
Acquisition of properties:			
- proved	£ x	£ x	£ x
- unproved	x	x	x
	______	______	______
	x	x	x
Exploration and appraisal costs	x	x	x
Development costs	x	x	x
Decommissioning costs provided			
- new provisions	x	x	x
- changes in estimates of amounts previously provided	x	x	x
	______	______	______
Total costs	£ x[*]	£ x	£ x
	=====	=====	=====
Company's share of combined costs of property acquisition, exploration and development of associates and joint ventures	£ x	£ x	£ x
	=====	=====	=====

[*]Total cost includes £x capitalised during the year.

Appendix 3 - Results of Operations

Results of Operations of Oil and Gas Exploration and Production Activities for the year ended 31 December xxxx

	Total	Area A	Area B
Turnover:			
- sales	£ x	£ x	£ x
- transfer	x	x	x
Total	x	x	x
Production costs	(x)		
Exploration and appraisal costs	(x)		
Depreciation, depletion and amortisation	(x)		
Decommissioning provision	(x)		
Profit before allocable taxes	x	x	x
Allocable taxes	(x)	(x)	(x)
Results of operations from exploration and production	£ x	£ x	£ x
Company's share of results of operations of associates and joint ventures	£ x	£ x	£ x

Appendix 4 – Net Commercial Oil and Gas Reserve Quantities

Net Commercial Oil and Gas Reserve Quantities for the year ended 31 December xxxx

	Total		Area A		Area B	
	Oil	Gas	Oil	Gas	Oil	Gas
Net commercial reserves, beginning of year:						
- commercial developed reserves	x	x	x	x	x	x
- commercial undeveloped reserves	x	x	x	x	x	x
	x	x	x	x	x	x
Changes during the year:						
- revisions of previous estimates	x	x	x	x	x	x
- purchases of reserves-in-place	x	x	x	x	x	x
- extensions, discoveries & other additions	x	x	x	x	x	x
- sales of reserves-in-place	(x)	(x)	(x)	(x)	(x)	(x)
- production	(x)	(x)	(x)	(x)	(x)	(x)
	x	x	x	x	x	x
Net commercial reserves, end of year:						
- commercial developed reserves	x	x	x	x	x	x
- commercial undeveloped reserves	x	x	x	x	x	x
	x	x	x	x	x	x
Company's share of net commercial reserves of associates and joint ventures at end of year	x	x	x	x	x	x

Of total net commercial oil and gas reserves at 31 December xxxx, x barrels of oil and y cubic feet of gas are attributable to minority shareholders of certain subsidiaries.

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Portland Press Ltd
Commerce Way
Whitehall Industrial Estate
Colchester CO2 8HP, UK.
Tel: +44 (0) 1206 796 351
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