Financial reporting in the oil and gas industry*

International Financial Reporting Standards
April 2008
The move to International Financial Reporting Standards (IFRS) is advancing the transparency and comparability of financial statements around the world. Many countries now require companies to prepare their financial statements in accordance with IFRS. National standards in other countries are being converged with IFRS. The global trend towards IFRS has gained significant further momentum with the US Securities and Exchange Commission’s (SEC) commitment to the standards, beginning with its decision to drop the requirement for foreign-listed companies in the US to reconcile to US GAAP.

The development of IFRS offers considerable long-term advantages for global companies but, along the way, it brings considerable challenges. The oil & gas industry is one of the world’s most global industries, characterised by the need for big upfront investment, often with great uncertainty about outcomes over a long-term time horizon. Its geopolitical, environmental, energy and natural resource supply and trading challenges, combined with often complex stakeholder and business relationships, has meant that the transition to IFRS has required some complex judgements about how to implement the new standards.

This edition of ‘Financial reporting in the oil & gas industry’ describes the financial reporting implications of IFRS across a number of areas selected for their particular relevance to oil & gas companies. It provides insights into how companies are responding to the various challenges and includes examples of accounting policies and other disclosures from published financial statements. It examines key developments in the evolution of IFRS in the industry. The International Accounting Standards Board (IASB), for example, has formed an Extractive Activities working group. However, formal guidance on many issues facing companies is unlikely to be available for some years. Another key development, of course, is convergence with US GAAP and the implications of the latest signals from the SEC for the oil & gas industry.

This publication does not describe all IFRSs applicable to oil & gas entities. The ever-changing landscape means that management should conduct further research and seek specific advice before acting on any of the more complex matters raised. PricewaterhouseCoopers has a deep level of insight into and commitment to helping companies in the sector report effectively. For more information or assistance, please do not hesitate to contact your local office or one of our specialist oil & gas partners.

Richard Paterson
Global Energy, Utilities and Mining Leader
# Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introduction</td>
<td>5</td>
</tr>
<tr>
<td>1 Oil &amp; Gas Value Chain &amp; Significant Accounting Issues</td>
<td>7</td>
</tr>
<tr>
<td>1.1 Exploration &amp; development</td>
<td>9</td>
</tr>
<tr>
<td>1.1.1 Exploration &amp; evaluation</td>
<td>9</td>
</tr>
<tr>
<td>1.1.2 Borrowing costs</td>
<td>11</td>
</tr>
<tr>
<td>1.1.3 Development expenditures</td>
<td>11</td>
</tr>
<tr>
<td>1.2 Production &amp; sales</td>
<td>11</td>
</tr>
<tr>
<td>1.2.1 Reserves &amp; resources</td>
<td>11</td>
</tr>
<tr>
<td>1.2.2 Depreciation of production and downstream assets</td>
<td>12</td>
</tr>
<tr>
<td>1.2.3 Product valuation issues</td>
<td>14</td>
</tr>
<tr>
<td>1.2.4 Impairment of production and downstream assets</td>
<td>14</td>
</tr>
<tr>
<td>1.2.5 Disclosure of resources</td>
<td>16</td>
</tr>
<tr>
<td>1.2.6 Decommissioning obligation</td>
<td>17</td>
</tr>
<tr>
<td>1.2.7 Financial instruments and embedded derivatives</td>
<td>18</td>
</tr>
<tr>
<td>1.2.8 Revenue recognition issues</td>
<td>21</td>
</tr>
<tr>
<td>1.2.9 Royalty and income taxes</td>
<td>22</td>
</tr>
<tr>
<td>1.2.10 Emission Trading Schemes</td>
<td>24</td>
</tr>
<tr>
<td>1.3 Company-wide issues</td>
<td>25</td>
</tr>
<tr>
<td>1.3.1 Production sharing agreements and concessions</td>
<td>25</td>
</tr>
<tr>
<td>1.3.2 Joint ventures</td>
<td>26</td>
</tr>
<tr>
<td>1.3.3 Business combinations</td>
<td>29</td>
</tr>
<tr>
<td>1.3.4 Functional currency</td>
<td>30</td>
</tr>
<tr>
<td>2 Developments from the IASB</td>
<td>33</td>
</tr>
<tr>
<td>2.1 Extractive activities research project</td>
<td>34</td>
</tr>
<tr>
<td>2.2 Borrowing costs</td>
<td>34</td>
</tr>
<tr>
<td>2.3 Emissions Trading Schemes</td>
<td>34</td>
</tr>
<tr>
<td>2.4 ED 9 Joint Arrangements</td>
<td>35</td>
</tr>
</tbody>
</table>
Contents

2.5 IFRS 3, Business combinations (revised) and IAS 27, Consolidated and separate financial statements (revised) 36

3 IFRS/US GAAP Differences 39

3.1 Exploration & evaluation 40

3.2 Reserves & resources 41

3.3 Depreciation of production and downstream assets 41

3.4 Inventory valuation issues 41

3.5 Impairment of production and downstream assets 42

3.6 Disclosure of resources 42

3.7 Decommissioning obligations 43

3.8 Financial instruments and embedded derivatives 44

3.9 Revenue recognition 46

3.10 Joint ventures 46

3.11 Business Combinations 48

4 Financial disclosure examples 51

4.1 Exploration & evaluation 52

4.2 Reserves & resources 53

4.3 Depreciation of production and downstream assets 54

4.4 Impairment 54

4.5 Decommissioning obligation 56

4.6 Financial instruments and embedded derivatives 56

4.7 Revenue recognition issues 57

4.8 Royalty and income taxes 57

4.9 Emission Trading Schemes 58

4.10 Joint ventures 58

4.11 Business combinations 60

4.12 Functional currency 61

Contact us 62
Introduction

What is the focus of this publication?

This publication considers the major accounting practices adopted by the oil and gas industry under International Financial Reporting Standards (IFRS).

The need for this publication has arisen due to:

• the absence of an extractive industries standard under IFRS;

• the adoption of IFRS by oil and gas entities across a number of jurisdictions, with overwhelming acceptance that applying IFRS in this industry will be a continual challenge; and

• ongoing transition projects in a number of other jurisdictions, for which companies can draw on the existing interpretations of the industry.

Who should use this publication?

This publication is intended for:

• executives and financial managers in the oil and gas industry, who are often faced with alternative accounting practices;

• investors and other users of oil and gas industry financial statements, so they can identify some of the accounting practices adopted to reflect unusual features unique to the industry; and

• accounting bodies, standard-setting agencies and governments throughout the world interested in accounting and reporting practices and responsible for establishing financial reporting requirements.

What is included?

Included in this publication are issues that we believe are of financial reporting interest due to:

• their particular relevance to oil and gas entities; and/or

• historical varying international practice.

The oil and gas industry has not only experienced the transition to IFRS, it has also seen:

• significant growth in corporate acquisition activity;

• increased globalisation;

• continued increase in its exposure to sophisticated financial instruments and transactions; and

• an increased focus on environmental and restoration liabilities.

This publication has a number of chapters designed to cover the main issues raised.

PricewaterhouseCoopers’ experience

This publication is based on the experience gained from the worldwide leadership position of PricewaterhouseCoopers in the provision of accounting services to the oil and gas industry. This leadership position enables PricewaterhouseCoopers’ Global Oil and Gas Industry Group to make recommendations and lead discussions on international standards and practice. The IASB has asked a group of national standard-setters to undertake a research project that will form the first step towards the development of an acceptable approach to resolving accounting issues that are unique to upstream extractive activities. The primary focus of the research project is on the financial reporting issues associated with reserves and resources. An advisory panel has been established to provide advice throughout the research project. PwC participates in the advisory panel. We support the IASB’s project to consider the promulgation of an accounting standard for the extractive industries; we hope that this will bring consistency to all areas of financial reporting in the extractive industries. The oil and gas industry is arguably one of the most global industries, and international comparability would be welcomed.

We hope you find this publication useful.
1 Oil & Gas Value Chain & Significant Accounting Issues
1 Oil & Gas Value Chain & Significant Accounting Issues

The objective of oil and gas operations is to find, extract, refine and sell oil and gas, refined products and related products. It requires substantial capital investment and long lead times to find and extract the hydrocarbons in challenging environmental conditions with uncertain outcomes. Exploration, development and production often takes place in joint ventures or joint activities to share the substantial capital costs. The outputs often need to be transported significant distances through pipelines, and tankers; gas volumes are increasingly liquefied, transported by special carriers and then regasified on arrival at its destination. Gas remains challenging to transport; thus many producers and utilities look for long-term contracts to support the infrastructure required to develop a major field, particularly off-shore.

The industry is exposed significantly to macro-economic factors such as commodity prices, currency fluctuations, interest-rate risk and political developments. The assessment of commercial viability and technical feasibility to extract the hydrocarbons is complex, and includes a number of significant variables. The industry can have a significant impact on the environment consequential to its operations and is often obligated to remediate any resulting damage. Despite all of these challenges, taxation of oil and gas extractive activity and the resultant profits is a major source of revenue for many governments. Governments are also increasingly sophisticated and looking to secure a significant share of any oil and gas produced on their sovereign territory.

This publication examines the accounting issues that are most significant for the oil and gas industry. The issues are addressed following the oil & gas value chain: exploration and development, production and sales of product, together with issues that are pervasive to the entity.

For published financial disclosure examples, see Section 4 on page 51.
1.1 Exploration & development

1.1.1 Exploration & evaluation (E&E)

Exploration costs are incurred to discover hydrocarbon resources. Evaluation costs are incurred to assess the technical feasibility and commercial viability of the resources found. Exploration, as defined in IFRS 6 ‘Exploration and Evaluation of Mineral Resources’, starts when the legal rights to explore have been obtained. Expenditure incurred before obtaining the legal right to explore must be expensed.

The accounting treatment of exploration and evaluation expenditures (capitalising or expensing) can have a significant impact on the financial statements and reported financial results, particularly for entities at the exploration stage with no production activities. This chapter considers the available alternatives for the treatment of such expenditure under IFRS.

Successful Efforts and Full Cost Method

Two broadly acknowledged methods have traditionally been used under national GAAP to account for E&E and subsequent development costs: successful efforts and full cost. Many different variants exist under national GAAP, but these are broadly similar. US GAAP has had a significant influence on the development of accounting practice in this area; entities in those countries that may not have specific rules often follow US GAAP by analogy, and US GAAP has influenced the accounting rules in other countries. The successful efforts method has perhaps been more widely used under national GAAP by integrated oil and gas companies, but is also used by many smaller upstream-only businesses. Costs incurred in finding, acquiring and developing reserves are capitalised on a field-by-field basis. Capitalised costs are allocated to commercially viable hydrocarbon reserves. Failure to discover commercially viable reserves means that the expenditure is charged to expense. Capitalised costs are depleted on a field-by-field basis as production occurs.

However, some upstream companies under national GAAP have historically used the full cost method. All costs incurred in searching for, acquiring and developing the reserves in a large geographic cost centre or pool, as opposed to individual fields, are capitalised. Cost centres are typically grouped on a country by country basis, although sometimes countries may be grouped together if the fields have similar or linked economic or geological characteristics. These larger cost pools are then depleted on a country basis as production occurs. If exploration efforts in the country or geologic formation are wholly unsuccessful, the costs are expensed. Full cost, generally, results in a larger deferral of costs during exploration and development and increased subsequent depletion charges.

Debate continues within the industry on the conceptual merits of both methods. IFRS 6 was issued to provide an interim solution for E&E costs pending the outcome of the wider extractive industries project by the IASB. Entities transitioning to IFRS can continue applying their current accounting policy for E&E. IFRS 6 provides an interim solution for exploration and evaluation costs, but does not apply to costs incurred once this phase is completed. The period of shelter provided by the standard is a relatively narrow one, and the impairment rules make the continuation of full cost past the E&E phase a challenge.

Policy choice for E&E under IFRS 6

An entity accounts for its E&E expenditure by developing an accounting policy that complies with the IFRS Framework or in accordance with the exemption permitted by IFRS 6. IFRS 6 allows an entity to continue to apply its existing accounting policy under national GAAP for E&E. The policy need not be in full compliance with the IFRS Framework.

Changes made to an entity’s accounting policy for E&E can only be made if they result in an accounting policy that is closer to the principles of the Framework. The change must result in a new policy that is more relevant and no less reliable or more reliable and no less relevant than the previous policy. The policy, in short, can move closer to the Framework but not further away. This restriction on changes to the accounting policy includes changes implemented on adoption of IFRS 6. The shelter of IFRS 6 only covers the exploration and evaluation phase, until the point at which the reserves’ commercial viability has been established.
**Initial recognition of E&E under the IFRS 6 exemption**

The exemption in IFRS 6 allows an entity to continue to apply the same accounting policy to exploration and evaluation expenditures as it did before the application of IFRS 6. The costs capitalised under this policy might not meet the IFRS Framework definition of an asset, as the probability of future economic benefits has not yet been demonstrated. IFRS 6 therefore deems these costs to be assets. E&E expenditures might therefore be capitalised earlier than would otherwise be the case under the Framework.

**Initial recognition of E&E under the Framework**

Expenditures incurred in exploration activities should be expensed unless they meet the definition of an asset. An entity recognises an asset when it is probable that economic benefits will flow to the entity as a result of the expenditure. The economic benefits might be available through commercial exploitation of hydrocarbon reserves or sales of exploration or further development rights. It is difficult for an entity to demonstrate at that stage that the recovery of exploration expenditure is probable. As a result, exploration expenditure has to be expensed. Virtually all entities transitioning to IFRS have chosen to use the IFRS 6 shelter rather than develop a policy under the Framework.

**Reclassification out of E&E under IFRS 6**

IFRS 6 requires that E&E assets are reclassified when evaluation procedures have been completed. E&E assets for which commercially-viable reserves have been identified are reclassified to development assets. E&E assets are tested for impairment immediately prior to reclassification out of E&E. The impairment testing requirements are described below.

**Impairment of E&E assets**

IFRS 6 introduces an alternative impairment-testing regime for E&E that differs from the general requirements for impairment testing. An entity assesses E&E assets for impairment only when facts and circumstances suggest that an impairment exists. Indicators of impairment include, but are not limited to:

- Rights to explore in an area have expired or will expire in the near future without renewal.
- No further exploration or evaluation is planned or budgeted.
- The decision to discontinue exploration and evaluation in an area because of the absence of commercial reserves.
- Sufficient data exists to indicate that the book value will not be fully recovered from future development and production.

The affected E&E assets should be tested for impairment once indicators have been identified. IFRS also introduces a notion of larger cash generating units (CGUs) for E&E assets. Entities are allowed to group E&E assets with producing assets, as long as the accounting policy is clear as to the grouping and such policy is applied consistently. The only limit is that each CGU or group of CGUs cannot be larger than the segment. The grouping of E&E assets with producing assets might therefore enable an impairment to be avoided.

Once the decision on commercial viability has been established, E&E assets are reclassified out of the E&E category. They are tested for impairment under the IFRS 6 policy adopted by the entity prior to reclassification. However, once assets have been reclassified out of E&E the normal impairment testing guidelines of IAS 36 *Impairment* apply. Successful E&E will be reclassified to development. Unsuccessful E&E must be written down to fair value less costs to sell, because the shelter afforded by grouping these assets with producing assets in a larger CGU shelter is no longer available.

Assets reclassified out of E&E are subject to the normal IFRS requirements of impairment testing at the CGU level and depreciation on a component basis. Impairment testing and depreciation on a pool basis is not acceptable.
1.1.2 Borrowing costs

The cost of an item of property, plant and equipment may include borrowing costs incurred for the purpose of acquiring or constructing it. Such borrowing costs may be capitalised if the asset takes a substantial period of time to get ready for its intended use. The capitalisation of borrowing costs under IAS 23 Borrowing Costs (Issued 1993) is an option, but one which must be applied consistently to all qualifying assets. However, amendments to IAS 23 that were published in 2007 and become effective from 1 January 2009 will require that all applicable borrowing costs be capitalised.

Borrowing costs should be capitalised while acquisition or construction is actively underway. These costs include the costs of specific funds borrowed for the purpose of financing the construction of the asset, and those general borrowings that would have been avoided if the expenditure on the qualifying asset had not been made. The general borrowing costs attributable to an asset’s construction should be calculated by reference to the entity’s weighted average cost of general borrowings.

1.1.3 Development expenditures

Development expenditures are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.

Development expenditures should generally be capitalised to the extent that they are necessary to bring the property to commercial production. Expenditures incurred after the point at which commercial production has commenced should only be capitalised if the expenditures meet the asset recognition criteria. This will be where the additional expenditure enhances the productive capacity of the producing property.

Dry holes

Some of the wells drilled in accordance with the development plan for the field may be unsuccessful (dry), but the results of the development work as a whole may further support the conclusion that the field has commercially viable reserves. The relevant unit of account for a field in the development or production stage is normally larger than the individual well. It is appropriate therefore to assess the economic benefits of the development dry hole in the context of the field as a whole and the development plan for that field. The information provided by a development dry hole is useful information and is applied through developing the field's infrastructure more precisely. The costs of a development dry hole should therefore normally be capitalised.

1.2 Production & sales

1.2.1 Reserves & Resources

The oil and gas natural resources found by an entity are its most important economic asset. The financial strength of the entity depends on the scale and quality of the resources it has the right to extract and sell. Resources are the source of future cash inflows from sale of hydrocarbons, and provide the basis for borrowing and for raising equity finance.

What are reserves?

Natural resources are outside the scope of IAS 16 Property, Plant and Equipment. The IASB is considering the accounting treatment for mineral resources and reserves as part of its Extractive Activities project. Entities record reserves at the historical cost of finding and developing reserves or acquiring them from third parties. The cost of finding and developing reserves is not directly influenced by the quantity of reserves, except to the extent that impairment may be an issue. The cost of reserves acquired in a business combination may be more closely associated with the fair value of reserves present. However, reserves and resources have a pervasive impact on an oil and gas entity’s financial statements, impacting on a number of significant areas. These include, but are not limited to:

- depletion, depreciation and amortisation;
- impairment and reversal of impairment;
- the recognition of future decommissioning and restoration obligations;
- termination and pension benefit cash flows;
- allocation of purchase price in business combinations.
Resources versus reserves

Resources are those volumes of oil and gas that are estimated to be present in the ground, which may or may not be economically recoverable.

Reserves are those resources that are anticipated to be commercially recovered from known accumulations from a specific date. The geological and engineering data available for specific accumulations will enable an assessment of the uncertainty/certainty of the reserves estimate. Reserves are classified as proved or unproved according to the degree of certainty/uncertainty associated with their estimated recoverability. These classifications do not arise from any definitions or guidance in the IFRSs. They are commonly and broadly used in the industry.

Several countries have their own definitions of reserves, for example China, Russia and Norway. Companies that are SEC registrants apply the SEC’s own definition of reserves for financial reporting purposes. There are also definitions developed by the professional societies, e.g., Society of Petroleum Engineers (SPE).

Proved reserves are estimated quantities of reserves that, based on geological and engineering data, appear reasonably certain to be recoverable in the future from known oil and gas reserves under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

Proved reserves are further sub-classified into those described as proved developed and proved undeveloped:

- proved developed reserves are those reserves that can be expected to be recovered through existing wells with existing equipment and operating methods;
- proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled proved acreage, or from existing wells where relatively major expenditure is required before the reserves can be extracted.

Unproved reserves are those reserves that technical or other uncertainties preclude from being classified as proved. Unproved reserves may be further categorised as probable and possible reserves:

- probable reserves are those additional reserves that are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves;
- possible reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

Estimation of reserves

Reserves estimates are usually made by petroleum reservoir engineers, sometimes by geologists but, as a rule, not by accountants.

Preparing reserve estimations is a complex process. It requires an analysis of information about the geology of the reservoir and the surrounding rock formations and analysis of the fluids and gases within the reservoir. It also requires an assessment of the impact of factors such as temperature and pressure on the recoverability of the reserves, taking account of operating practices, statutory and regulatory requirements, costs and other factors that will affect the commercial viability of extracting the reserves. As an oil and gas field is developed and produced, more information about the mix of oil, gas, water, etc, reservoir pressure, and other relevant data is obtained and used to update the estimates of recoverable reserves. Estimates of reserves are therefore revised over the life of the field.

There are standards for estimating and auditing oil and gas reserves information developed by the Society of Petroleum Engineers. The SPE Standards are not binding on petroleum engineers but do provide estimation and reporting guidance.

1.2.2 Depreciation of production and downstream assets

The accumulated costs from E&E, development and production phases are amortised over expected total production using a unit of production (UOP) basis. UOP is the most
appropriate amortisation method because it reflects the pattern of consumption of the reserves’ economic benefits. However, straightline amortisation may be appropriate for some assets.

Depletion, depreciation and amortisation (DD&A)
The IFRSs do not prescribe what basis should be used for the UOP calculation. Many entities use only proved developed; others use all proved or both proved and probable. The basis of the UOP calculation is an accounting policy choice, and should be applied consistently.

If proved and proved undeveloped reserves are used, then an adjustment should be considered when calculating the amortisation charge to reflect the future development costs that need to be incurred to access the undeveloped reserves.

The total production used for DD&A of assets that are subject to a lease or licence should be restricted to the total production expected to be produced during the licence/lease term. Renewals of the licence/lease are only assumed if there is evidence to support probable renewal without significant cost.

Components
IFRS has a specific requirement for ‘component’ depreciation, as described in IAS 16. Each significant part of an item of property, plant and equipment is depreciated separately. Significant parts of an asset that have similar useful lives and pattern of consumption can be grouped together. This requirement can create complications for oil & gas entities, as there are many assets that include components with a shorter useful life than the asset as a whole.

Productive assets are often large and complex installations. Assets are expensive to construct, tend to be exposed to harsh environmental or operating conditions and require periodic replacement or repair. Large network or infrastructure assets might comprise a significant number of components, many of which will have differing useful lives. Examples include gas treatment installations, refineries, chemical plants, distribution networks and offshore platforms, including the supporting infrastructure and pipelines.

The significant components of these types of assets must be separately identified, such as the compressors in a pipeline. It can be a complex process, particularly on transition to IFRS, as the recordkeeping may not have been required to comply with national GAAP.

Some components can be identified by considering the routine shutdown/turnaround schedules and the replacement and maintenance routines associated with these. Consideration should also be given to those components that are prone to technological obsolescence, corrosion or wear and tear more severe than that of the other portions of the larger asset.

Depreciation of components
Those identified components that have a shorter useful life than the remainder of the asset should be depreciated to the recoverable amount over that shorter useful life. The remaining carrying amount of the component is derecognised on replacement and the cost of the replacement part is capitalised. A complication can arise where upstream assets are largely depreciated on a UOP basis but specific assets are consumed in a more straight-line manner. A potential workaround exists if production is stable over time. The production expected during the period can be estimated and the components depreciated over that number of units. This method needs to be periodically assessed to determine that it continues to approximate a straight-line method.

The calculation of a depreciation charge cannot be avoided on the basis that a high level of maintenance expenditure is incurred that will continuously maintain the network’s operating capacity. The practice of assuming that the maintenance charge approximates the depreciation charge and thus avoiding the calculation of depreciation on an asset or component basis, known as renewals accounting, is not acceptable under IFRS.

The costs of performing a turnaround/overhaul are capitalised as a component of the plant provided this provides access to future economic benefits, but turnaround/overhaul costs that do not relate to the replacement of components or the installation of new assets should be expensed as incurred. Turnaround/overhaul costs should not be accrued over the period between
the turnarounds/overhauls because there is no legal or constructive obligation to perform the turnaround/overhaul – the entity could choose to cease operations at the plant and hence avoid the turnaround/overhaul costs.

1.2.3 Product valuation issues

Accounting for linefill

Some items of property, plant and equipment, such as pipelines, refineries and gas storage, require a certain minimum level of product to be maintained in them in order for them to operate efficiently. Such product should be classified as part of the property, plant and equipment because it is necessary to bring the PPE to its required operating condition. The product will therefore be recognised as a component of the PPE at cost and subject to depreciation to estimated residual value.

However, product that an entity owns but stores in PPE owned by a third party continues to be classified as inventory, for example all gas in a rented storage facility. It does not represent a component of the third party’s PPE nor a component of PPE owned by the entity. Such product should therefore be measured at FIFO or weighted average cost.

Determining net realisable value for oil inventories

Oil produced and purchased for use by an entity is valued at the lower of cost and net realisable value. Determining net realisable value requires consideration of the estimated selling price in the ordinary course of business less the estimated costs to complete the processing of the inventory (where appropriate) and less the estimated costs necessary to sell the inventories. An entity determines the estimated selling price of the oil/oil product using the market price for oil at the balance sheet date, or where appropriate, the forward price curve for oil at the balance sheet date. Movements in the oil price after the balance sheet date typically reflect changes in the market conditions after that date and therefore should not be reflected in the calculation of net realisable value.

1.2.4 Impairment of production and downstream assets

The oil and gas industry is distinguished by the significant capital investment required. The heavy investment in fixed assets leaves the industry exposed to adverse economic conditions and therefore impairment charges.

Oil and gas assets should be tested for impairment whenever indicators of impairment exist. The normal measurement rules for impairment apply to assets with the exception of the grouping of E&E assets with existing producing cash generating units (CGUs) as described in section 1.1.1.

Impairment indicators

Impairment triggers relevant for the petroleum sector include declining market prices for oil and gas, significant downward reserve revisions, increased regulation or tax changes, deteriorating local conditions such that it may become unsafe to continue operations and expropriation of assets.

Impairment indicators can also be internal in nature. Evidence that an asset or CGU has been damaged or become obsolete is an impairment indicator; for example a refinery destroyed by fire is, in accounting terms, an impaired asset. Other indicators of impairment are a decision to sell or restructure a CGU or evidence that business performance is less than expected.

Management should be alert to indicators on a CGU basis; for example learning of a fire at an individual petrol station would be an indicator of impairment for that station as a separate CGU. However, generally, management is likely to identify impairment indicators on a regional or area basis, reflective of how they manage their business. Once an impairment indicator has been identified, the impairment test must be performed at the individual CGU level, even if the indicator was identified at a regional level.

Cash generating units

A CGU is the smallest group of assets that generates cash inflows largely independent of other assets or groups of assets. A CGU in an upstream entity will often be identified as a field and its supporting infrastructure assets.
Production, and therefore cash flows, can be associated with individual wells. However, the field investment decision is made based on expected field production, not a single well, and all wells are typically dependent on the field infrastructure.

An entity operating in the downstream business may own petrol stations, clustered in geographic areas to benefit from management oversight, supply and logistics. The petrol stations, by contrast, are not dependent on fixed infrastructure and generate largely independent cash inflows.

**Calculation of recoverable amount**

Impairments are recognised if a CGU’s carrying amount exceeds its recoverable amount. Recoverable amount is the higher of fair value less costs to sell (FVLCTS) and value in use (VIU).

**Fair value less costs to sell (FVLCTS)**

Fair value less costs to sell is the amount that a market participant would pay for the asset or CGU, less the costs of sale. The use of discounted cash flows for FVLCTS is permitted where there is no readily available market price for the asset or where there are no recent market transactions for the fair value to be determined through a comparison between the asset being tested for impairment and a recent market transaction. However, where discounted cash flows are used, the inputs must be based on external, market-based data.

The projected cash flows for FVLCTS therefore include the assumptions that a potential purchaser would include in determining the price of the asset. Thus industry expectations for the development of the asset may be taken into account which may not be permitted under VIU. However, the assumptions and resulting value must be based on recent market data and transactions.

Post-tax cash flows are used when calculating FVLCTS using a discounted cash flow model. The discount rate applied in FVLCTS will be a post-tax market rate based on a typical industry participant’s cost of capital.

**Value in use (VIU)**

VIU is the present value of the future cash flows expected to be derived from an asset or CGU in its current condition. Determination of VIU is subject to the explicit requirements of IAS 36. The cash flows are based on the asset that the entity has now and must exclude any plans to enhance the asset or its output in the future but includes expenditure necessary to maintain the current performance of the asset. The VIU cash flows for assets that are under construction and not yet complete (e.g., an oil or gas field that is part-developed) should include the cash flows necessary for their completion and the associated additional cash inflows or reduced cash outflows.

Any foreign currency cash flows are projected in the currency in which they will be earned, and discounted at a rate appropriate for that currency. The resulting value is translated to the entity’s functional currency using the spot rate at the date of the impairment test.

The discount rate used for VIU is always pre-tax and applied to pre-tax cash flows. This is often the most difficult element of the impairment test, as pre-tax rates are not available in the market place. Grossing up the post tax rate does not give the correct answer unless no deferred tax is involved. Arriving at the correct pre-tax rate is a complex mathematical exercise.

**Contracted cash flows in VIU**

The cash flows prepared for a VIU calculation should reflect management’s best estimate of the future cash flows expected to be generated from the assets concerned. Purchases and sales of commodities are included in the VIU at the spot price at the date of the impairment test, or if appropriate, prices obtained from the forward price curve at the date of the impairment test.

However, management should use the contracted price in its VIU calculation for any commodities unless the contract is already on the balance sheet at fair value. A commodity contract that can be settled net in cash and for which the own-use exception cannot be claimed, for example, is recognised separately on the balance sheet at fair value as a derivative. Including the contracted prices of such a
contract would double count the effects of the contract. Impairment of financial instruments that are within the scope of IAS 39 *Financial Instruments: Recognition and Measurement* is addressed by IAS 39 and not IAS 36.

The cash flow effects of hedging instruments such as caps and collars for commodity purchases and sales are also excluded from the VIU cash flows. These contracts are also accounted for in accordance with IAS 39.

1.2.5 Disclosure of resources

A key indicator for evaluating the performance of oil and gas entities are their existing reserves and the future production and cash flows expected from them. Some national accounting standards and securities regulators require supplemental disclosure of reserve information, most notably the Statement on Financial Accounting Standards (FAS) 69 and Securities and Exchange Commission (SEC) regulations. There are also recommendations on accounting practices issued by industry bodies – Statements of Recommended Practice (SORPs) – which cover Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities. However, there are no reserve disclosure requirements under IFRS.

IAS 1 *Presentation of Financial Statements* requires that an entity’s financial statements should provide additional information that is not presented on the face of the financial statements but which is necessary for a fair presentation. IAS 1 allows an entity to consider the pronouncements of other standard-setting bodies and accepted industry practices in the absence of specific IFRS guidance when developing accounting policies. Many entities provide supplemental information with the financial statements because of the unique nature of the oil and gas industry and the clear desire of investors and other users of the financial statements to receive information about reserves. The information is usually supplemental to the financial statements, and is not covered by the independent auditor’s opinion.

Information about quantities of oil and gas reserves and changes therein is essential for users to understand and compare oil and gas companies’ financial position and performance. Entities should consider presenting reserve quantities and changes on a reasonably aggregate basis. Where certain reserves are subject to particular risks, those risks should be identified and communicated. Reserve disclosures accompanying the financial statements should be consistent with those reserves used for financial statement purposes. For example, proven and probable reserves or proved developed and undeveloped reserves might be used for depreciation, depletion and amortisation calculations.

The categories of reserves used and their definitions should be clearly described. Reporting a ‘value’ for reserves and a common means of measuring that value have long been debated, and there is no consensus among national standard-setters permitting or requiring value disclosure. There is, at present, no globally agreed method to ‘value’ disclosures. However, there are globally accepted engineering definitions of reserves that take into account economic factors. These definitions may be a useful benchmark for disclosing future cash flow information about reserves for investors and other users of financial statements to evaluate.

The disclosure of key assumptions concerning the future, and other key sources of estimation uncertainty at the balance sheet date, is required by IAS 1. Given that the reserves and resources have a pervasive impact, this normally results in entities providing disclosure about hydrocarbon resource and reserve estimates, for example:

- hydrocarbon resource and reserve estimates:
  - methodology used; and
  - key assumptions;
- the sensitivity of carrying amounts of assets and liabilities to the hydrocarbon resource and reserve estimates used;
- the range of reasonably possible outcomes within the next financial year in respect of the carrying amounts of the assets and liabilities affected; and
- an explanation of changes made to past hydrocarbon resource and reserve estimates, including changes to underlying key assumptions.

Other information – for example, potential future costs to be incurred to acquire, develop and
produce reserves – may help users of financial statements to assess the entity’s performance. Supplementary disclosure of such information with IFRS financial statements is useful, but it should be consistently reported, the underlying basis clearly disclosed and based on a common guideline or practice, such as the Society of Petroleum Engineers definitions.

Companies already presenting supplementary information regarding reserves under their national GAAP may want to continue providing such information until the IASB publishes a comprehensive standard, setting out the supplementary information disclosure requirements under IFRS.

1.2.6 Decommissioning obligations

The oil and gas industry can have a significant impact on the environment. Decommissioning or environmental restoration work at the end of the useful life of a plant or other installation may be required by law, the terms of operating licences or an entity’s stated policy and past practice. An entity that promises to remediate damage, even when there is no legal requirement, may have created a constructive obligation and thus a liability under IFRS. There may also be environmental clean-up obligations for contamination of land that arises during the operating life of a refinery or other installation. The associated costs of remediation/restoration can be significant. The accounting treatment for decommissioning costs is therefore critical.

Decommissioning provisions

A provision is recognised when an obligation exists to perform the clean-up. The local legal regulations should be taken into account when determining the existence and extent of the obligation. Obligations to decommission or remove an asset are created at the time the asset is put in place. An offshore drilling platform, for example, must be removed at the end of its useful life. The obligation to remove it arises from its placement. The obligation does not change in substance if the platform produces 10,000 barrels or 1,000,000. Entities recognise decommissioning provisions at the present value of the expected future cash flows that will be required to perform the decommissioning.

The cost of the provision is recognised as part of the cost of the asset when it is put in place and depreciated over the asset’s useful life. The total cost of the fixed asset, including the cost of decommissioning, is depreciated on the basis that best reflects the consumption of the economic benefits of the asset. Provisions for decommissioning and restoration are recognised even if the decommissioning is not expected to be performed for a long time, for example 80 to 100 years. This may prove challenging in the downstream business, for example refineries when decommissioning is not expected in the short to medium term.

The effect of the time to expected decommissioning will be reflected in the discounting of the provision. The discount rate used is the pre-tax rate that reflects current market assessments of the time value of money. Entities also need to reflect the specific risks associated with the decommissioning liability. Different decommissioning obligations will, naturally, have different inherent risks, for example different uncertainties associated with the methods, the costs and the timing of decommissioning. The risks specific to the liability can be reflected either in the pre-tax cash flow forecasts prepared or in the discount rate used.

Revisions to decommissioning provisions

Decommissioning provisions are updated at each balance sheet date for changes in the estimates of the amount or timing of future cash flows and changes in the discount rate. Changes to provisions that relate to the removal of an asset are added to or deducted from the carrying amount of the related asset in the current period. The adjustments to the asset are restricted, however. The asset cannot decrease below zero and cannot increase above its recoverable amount:

- if the decrease of provision exceeds the carrying amount of the asset, the excess is recognised immediately in profit or loss;
- adjustments that result in an addition to the cost of the asset are assessed to determine if the new carrying amount is fully recoverable or not. An impairment test is required if there is an indication that the asset may not be fully recoverable.
The accretion of the discount on a decommissioning liability is recognised as part of finance expense in the income statement.

1.2.7 Financial instruments and embedded derivatives

The accounting for financial instruments can have a major impact on an oil & gas entity’s financial statements. Many use a range of derivatives to manage the commodity, currency and interest-rate risks to which they are operationally exposed. Other, less obvious, sources of financial instruments issues arise through both the scope of IAS 39 and the rules around accounting for embedded derivatives.

Many entities that are solely engaged in producing, refining and selling commodities, may be party to commercial contracts that are either wholly within the scope of IAS 39 or contain embedded derivatives from pricing formulas or currency.

Scope of IAS 39

Contracts to buy or sell a non-financial item, such as a commodity, that can be settled net in cash or another financial instrument, or by exchanging financial instruments, are within the scope of IAS 39. They are treated as derivatives and are marked to market through the income statement. Contracts that are for an entity’s ‘own-use’ are exempt from the requirements of IAS 39 but these ‘own-use’ contracts may include embedded derivatives that may be required to be separately accounted for. An ‘own-use’ contract is one that was entered into and continues to be held for the purpose of the receipt or delivery of the non-financial item in accordance with the entity’s expected purchase, sale or usage requirements. In other words, it will result in physical delivery of the commodity. The ‘net settlement’ notion in IAS 39 is quite broad.

A contract to buy or sell a non-financial item can be net settled in any of the following ways:

(a) the terms of the contract permit either party to settle it net in cash or another financial instrument;

(b) the entity has a practice of settling similar contracts net, whether:
   • with the counterparty;
   • by entering into offsetting contracts; or
   • by selling the contract before its exercise or lapse;

(c) the entity has a practice, for similar items, of taking delivery of the underlying and selling it within a short period after delivery for the purpose of generating a profit from short-term fluctuations in price or dealer’s margin;

(d) the commodity that is the subject of the contract is readily convertible to cash.

Application of ‘own-use’

Own-use applies to those contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item. The practice of settling similar contracts net prevents an entire category of contracts from qualifying for the own-use treatment (ie, all similar contracts must then be recognised as derivatives at fair value).

A contract that falls into category (b) or (c) above cannot qualify for own-use treatment. These contracts must be accounted for as derivatives at fair value. Contracts subject to the criteria described in (a) or (d) above are evaluated to see if they qualify for own-use treatment.

Many contracts for commodities such as oil and gas meet criterion (d) above (ie, readily convertible to cash) when there is an active market for the commodity. An active market exists when prices are publicly available on a regular basis and those prices represent regularly occurring arm’s length transactions between willing buyers and willing sellers. Consequently, sale and purchase contracts for commodities in locations where an active market exists must be accounted for at fair value unless own-use treatment can be evidenced. An entity’s policies, procedures and internal controls are therefore critical in determining the appropriate treatment of its commodity contracts.

Own-use is not an election. A contract that meets the own-use criteria cannot be selectively fair valued unless it otherwise falls into the scope of IAS 39. If an own-use contract contains one or
more embedded derivatives, an entity may designate the entire hybrid contract as a financial asset or financial liability at fair value through profit or loss unless:

(a) the embedded derivative(s) does not significantly modify the cash flows of the contract; and

(b) it is clear with little or no analysis that separation of the embedded derivative is prohibited.

However, the IASB has proposed to restrict the ability to designate the entire hybrid instrument as a financial asset or financial liability at fair value through profit or loss. The proposal to be included in the IASB’s 2008 Annual Improvements project will restrict this designation to host contracts that are financial instruments in the scope of IAS 39.

Further discussion on embedded derivatives is presented in the following section.

**Measurement of long-term contracts that do not qualify for ‘own-use’**

Long-term commodity contracts are not uncommon, particularly for purchase and sale of natural gas. Some of these contracts may be within the scope of IAS 39 as they contain net settlement provisions and do not get own-use treatment. These contracts are measured at fair value using the valuation guidance in IAS 39 with changes recorded in the income statement. There may not be market prices for the entire period of the contract. For example, there may be prices available for the next three years and then some prices for specific dates further out. This is described as having illiquid periods in the contract. These contracts are valued using valuation techniques in the absence of an active market for the entire contract term.

Valuation is complex and is intended to establish what the transaction price would have been on the measurement date in an arm’s length exchange motivated by normal business considerations. Therefore it:

(a) incorporates all factors that market participants would consider in setting a price, making maximum use of market inputs and relying as little as possible on entity-specific inputs;

(b) is consistent with accepted economic methodologies for pricing financial instruments; and

(c) is tested for validity using prices from any observable current market transactions in the same instrument or based on any available observable market data.

The assumptions used to value long-term contracts are updated at each balance sheet date to reflect changes in market prices, the availability of additional market data and changes in management’s estimates of prices for any remaining illiquid periods of the contract. Clear disclosure of the policy and approach, including significant assumptions, are crucial to ensure that users understand the entity’s financial statements.

**Day-one profits**

Commodity contracts that fall within the scope of IAS 39 and fail to qualify for own-use treatment have the potential to create day-one gains. A day-one gain is the difference between the fair value of the contract at inception as calculated by a valuation model and the amount paid to enter the contract. The contracts are initially recognised under IAS 39 at fair value. Any such profits or losses can only be recognised if the fair value of the contract:

(1) is evidenced by other observable market transactions in the same instrument; or

(2) is based on valuation techniques whose variables include only data from observable markets.

Thus, the profit must be supported by objective market-based evidence. Observable market transactions must be in the same instrument (ie, without modification or repackaging and in the same market where the contract was originated). Prices must be established for transactions with different counterparties for the same commodity and for the same duration at the same delivery point.

Any day-one profit or loss that is not recognised at initial recognition is recognised subsequently only to the extent that it arises from a change in a factor (including time) that market participants would consider in setting a price. Commodity
contracts include a volume component, and oil and gas entities are likely to recognise the deferred gain/loss and release it to profit or loss on a systematic basis as the volumes are delivered, or as observable market prices become available for the remaining delivery period. The recognition of the day-one gain/losses may change as the result of the IASB project on Fair Value Measurements.

**Volume flexibility (optionality)**

Long-term commodity contracts frequently offer the counterparty flexibility in relation to the quantity of the commodity to be delivered under the contract. A supplier that gives a purchaser volume flexibility may have created a written option. This will often prevent the supplier from claiming the own-use exemption. A written option cannot be entered into for the purpose of the receipt or delivery of a non-financial item in accordance with the entity’s expected purchase, sale or usage requirements. A contract containing a written option must be accounted for in accordance with IAS 39 if it can be settled net in cash, eg, when the item that is subject of the contract is readily convertible into cash.

Contracts may include volume flexibility but not contain a written option if the purchaser did not pay a premium for the optionality. Receipt of a premium to compensate the supplier for the risk that the purchaser may not take the optional quantities specified in the contract is one of the distinguishing features of a written option. The premium might be explicit in the contract or implicit in the pricing. It is necessary to consider whether a net premium is received either at inception or over the contract’s life in order to determine the accounting treatment. If no premium can be identified, other terms of the contract may need to be examined to determine whether it contains a written option; in particular, whether the buyer is able to secure economic value from the option’s presence.

**Embedded derivatives**

Long-term commodity purchase and sale contracts frequently contain a pricing clause (ie, indexation) based on a commodity other than the commodity deliverable under the contract. Such contracts contain embedded derivatives that may have to be separated and accounted for under IAS 39 as a derivative. Examples are gas prices that are linked to the price of oil or other products, or a pricing formula that includes an inflation component.

An embedded derivative is a derivative instrument that is combined with a non-derivative host contract (the ‘host’ contract) to form a single hybrid instrument. An embedded derivative causes some or all of the cash flows of the host contract to be modified, based on a specified variable. An embedded derivative can arise through market practices or common contracting arrangements.

An embedded derivative is separated from the host contract and accounted for as a derivative if:

(a) the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract;

(b) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and

(c) the hybrid (combined) instrument is not measured at fair value with changes in fair value recognised in the profit or loss (ie, a derivative that is embedded in a financial asset or financial liability at fair value through profit or loss is not separated).

Embedded derivatives that are not closely related must be separated from the host contract and accounted for at fair value, with changes in fair value recognised in the income statement. It may not be possible to measure the embedded derivative. Therefore, the entire combined contract must be measured at fair value, with changes in fair value recognised in the income statement.

An embedded derivative that is required to be separated may be designated as a hedging instrument, in which case the hedge accounting rules are applied.

A contract that contains one or more embedded derivatives can be designated as a contract at fair value through profit or loss at inception, unless:
(a) the embedded derivative(s) does not significantly modify the cash flows of the contract; and

(b) it is clear with little or no analysis that separation of the embedded derivative(s) is prohibited.

Assessing whether embedded derivatives are closely related

All embedded derivatives must be assessed to determine if they are ‘closely related’ to the host contract at the inception of the contract. A pricing formula that is indexed to something other than the commodity delivered under the contract could introduce a new risk to the contract. Some common embedded derivatives that routinely fail the closely-related test are indexation to an unrelated published market price and denomination in a foreign currency that is not the functional currency of either party and not a currency in which such contracts are routinely denominated in transactions around the world.

The assessment of whether an embedded derivative is closely related is both qualitative and quantitative, and requires an understanding of the economic characteristics and risks of both instruments.

In the absence of an active market price for a particular commodity, management should consider how other contracts for that particular commodity are normally priced. It is common for a pricing formula to be developed as a proxy for market prices. When it can be demonstrated that a commodity contract is priced by reference to an identifiable industry ‘norm’ and contracts are regularly priced in that market according to that norm, the pricing mechanism does not modify the cash flows under the contract and is not considered an embedded derivative.

Timing of assessment of embedded derivatives

All contracts need to be assessed for embedded derivatives at the date when the entity first becomes a party to the contract. Subsequent reassessment of embedded derivatives is prohibited unless there is a significant change in the terms of the contract, in which case reassessment is required. A significant change in the terms of the contract has occurred when the expected future cash flows associated with the embedded derivative, host contract, or hybrid contract have significantly changed relative to the previously expected cash flows under the contract.

A first-time adopter assesses whether an embedded derivative is required to be separated from the host contract and accounted for as a derivative on the basis of the conditions that existed at the later of the date it first became a party to the contract and the date a reassessment is required.

The same principles apply to an entity that purchases a contract containing an embedded derivative. The date of purchase is treated as the date when the entity first becomes party to the contract.

1.2.8 Revenue recognition issues

Revenue recognition, particularly for upstream activities, can present some significant challenges. Production often takes place in joint ventures or through concessions, and entities need to analyse the facts and circumstances to determine when and how much revenue to recognise. Crude oil and gas may need to be moved long distances and need to be of a specific type to meet refinery requirements. Entities may exchange product to meet logistical, scheduling or other requirements. This section looks at these common issues. Revenue recognition in production-sharing agreements (PSAs) is discussed in section 1.3.1.

Overlift and underlift

Many joint ventures (JV) share the physical output (for example crude oil) between the joint venture partners. Each JV partner is then responsible for either using or selling the oil it takes.

The physical nature of the taking (lifting) of oil is such that it is often more efficient for each partner to lift a full tanker-load of oil at a time. A lifting schedule identifies the order and frequency with which each partner can lift. At the balance sheet date the amount of oil lifted by each partner may not be equal to its equity interest in the field. Some partners will have taken more than their share (overlifted) and others will have taken less than their share (underlifted).
Overlift and underlift are in effect a sale of oil at the point of lifting by the underlifter to the overlifter. The criteria for revenue recognition in IAS 18 Revenue paragraph 14 are considered to have been met. Overlift is therefore treated as a purchase of oil by the overlifter from the underlifter.

The sale of oil by the underlifter to the overlifter should be recognised at the market price of oil at the date of lifting. Similarly the overlifter should reflect the purchase of oil at the same value.

The extent of underlift by a partner is reflected as an asset in the balance sheet and the extent of overlift is reflected as a liability. An underlift asset is the right to receive additional oil from future production without the obligation to fund the production of that additional oil. An overlift liability is the obligation to deliver oil out of the entity’s equity share of future production.

The initial measurement of the overlift liability and underlift asset is at the market price of oil at the date of lifting, consistent with the measurement of the sale and purchase. Subsequent measurement depends on the terms of the JV agreement. JV agreements that allow the net settlement of overlift and underlift balances in cash will fall within the scope of IAS 39 unless the own-use exemption applies.

Overlift and underlift balances that fall within the scope of IAS 39 must be remeasured to the current market price of oil at the balance sheet date. The change arising from this remeasurement is included in the income statement as other income/expense rather than revenue or cost of sales.

Overlift and underlift balances that do not fall within the scope of IAS 39 should be measured at the lower of carrying amount and current market value. Any remeasurement should be included in other income/expense rather than revenue or cost of sales.

Exchanges

Energy companies exchange crude or refined oil products with other energy companies to achieve operational objectives. This is often done to save on transportation costs by exchanging a quantity of product A in location X for a quantity of product A in location Y. Variations on this arise – sometimes there are variations in the quality of the product, sometimes different products are exchanged. Balancing payments are made to reflect differences in the values of the products exchanged where appropriate.

The nature of the exchange will determine if it is a like-for-like exchange or an exchange of dissimilar goods. A like-for-like exchange doesn’t give rise to revenue recognition or gains, but an exchange of dissimilar goods is accounted for gross, giving rise to revenue recognition and gains or losses.

The exchange of crude oil, even where the qualities of the crude differ, is usually treated as an exchange of similar products and accounted for at book value. Any balancing payment made or received to reflect minor differences in quality or location should be adjusted against the carrying value of the inventory. There may, however, be unusual circumstances where the facts of the exchange suggest that there are significant differences between the crude oil exchanged. The transaction should be accounted for as a sale of one product and the purchase of the other at fair values in these circumstances. A significant cash element in the transaction is an indicator that the transaction may be a sale and purchase of dissimilar products.

1.2.9 Royalty and income taxes

Petroleum taxes generally fall into two categories – those that are calculated on profits earned (income taxes) and those calculated on production or sales (royalty or excise taxes). The categorisation is crucial: royalty and excise taxes do not form part of revenue, while income taxes usually require deferred tax accounting but form part of revenue.

Petroleum taxes – royalty and excise

Petroleum taxes that are calculated by applying a tax rate to a measure of revenue or volume do not fall within the scope of IAS 12 Income Taxes and are not income taxes. They do not form part of revenue or give rise to deferred tax liabilities. Revenue-based and volume-based taxes are recognised when the production occurs or revenue arises. These taxes are most often described as royalty or excise taxes. They are measured in accordance with the relevant tax
legislation and a liability is recorded for amounts due that have not yet been paid to the government.

Royalty and excise taxes are in effect the government’s share of the natural resources exploited and are a share of production free of cost. They may be paid in cash or in kind. If in cash, the entity sells the oil or gas and remits to the government its share of the proceeds. Royalty payments in cash or in kind are excluded from gross revenues and costs.

**Petroleum taxes based on profits**

Petroleum taxes that are calculated by applying a tax rate to a measure of profit fall within the scope of IAS 12. The profit measure used to calculate the tax is that required by the relevant tax legislation and will, accordingly, differ from the IFRS profit measure. Profit in this context is revenue less costs as defined by the relevant tax legislation, and thus might include costs that are capitalised for financial reporting purposes. However it is not, for example, an allocation of profit oil in a PSA. Examples of taxes based on profits include Petroleum Revenue Tax in the UK, Norwegian Petroleum Tax and Australian Resource Rent Tax.

Petroleum taxes on income are often ‘super’ taxes applied in addition to ordinary corporate income taxes. The tax may apply only to profits arising from specific geological areas or sometimes on a field-by-field basis within larger areas. The petroleum tax may or may not be deductible when determining corporate income tax; this does not change its character as a tax on income. The computation of the tax is often complicated. There may be a certain number of barrels or bcm that are free of tax, accelerated depreciation and additional tax credits for investment. Often there is a minimum tax computation as well. Each complicating factor in the computation must be separately evaluated and accounted for in accordance with IAS 12.

Deferred tax must be calculated in respect of all taxes that fall within the scope of IAS 12. The deferred tax is calculated separately for each tax by identifying the temporary differences between the IFRS carrying amount and the corresponding tax base for each tax. Petroleum income taxes may be assessed on a field-specific basis or a regional basis. An IFRS balance sheet and a tax balance sheet will be required for each area or field subject to separate taxation for the calculation of the deferred tax.

The tax rate applied to the temporary differences will be the statutory rate for the relevant tax. The statutory rate may be adjusted for certain allowances and reliefs (eg, tax free barrels) in certain limited circumstances where the tax is calculated on a field-specific basis without the opportunity to transfer profits or losses between fields.

**Taxes in PSAs**

Production sharing agreements are discussed in further detail in Chapter 1.3.1. However, a crucial question arises about the taxation of PSAs – when are amounts paid to the government as income tax (and thus form part of revenue) and when are amounts a royalty and excluded from revenue. Some PSAs include a requirement for the national oil company or another government body to pay income tax on behalf of the operator of the PSA. When does tax paid on behalf of an operator form part of revenue and income tax expense?

The revenue arrangements and tax arrangements are unique in each country and can vary within a country, such that each major PSA is usually unique. However, there are common features that will drive the assessment as income tax, royalty or government share of production. Among the common features that should be considered in making this determination are:

- whether a well established income tax regime exists;
- whether the tax is computed on a measure of profits; and
- whether the PSA requires the payment of income taxes, the filing of a tax return and establishes a legal liability for income taxes until such liability is discharged by payment from the entity or a third party.

**Tax paid in cash or in kind**

Tax is usually paid in cash to the relevant tax authorities. However, some governments allow payment of tax through the delivery of oil instead
of cash for income taxes, royalty and excise taxes and amounts due under licences, production sharing contracts and the like.

The accounting for the tax charge and the settlement through oil should reflect the substance of the arrangement. Determining the accounting is straightforward if it is an income tax (see definition above) and is calculated in monetary terms. The volume of oil used to settle the liability is then determined by reference to the market price of oil. The entity has in effect ‘sold’ the oil and used the proceeds to settle its tax liability. These amounts are appropriately included in gross revenue and tax expense.

Arrangements where the liability is calculated by reference to the volume of oil produced without reference to market prices can make it more difficult to identify the appropriate accounting. These are most often a royalty or volume-based tax. The accounting should reflect the substance of the agreement with the government. Some arrangements will be a royalty fee, some will be a traditional profit tax, some will be an appropriation of profits and some will be a combination of these and more. The agreement or legislation under which oil is delivered to a government must be reviewed to determine the substance and hence the appropriate accounting. Different agreements with the same government must each be reviewed as the substance of the arrangement, and hence the accounting may differ from one to another.

**Tax ‘paid on behalf’ (POB)**

POB arrangements are varied, but generally arise when a government entity will pay the income tax due by a foreign upstream entity to the government on behalf of the foreign upstream entity. This occurs where the upstream entity is the operator of fields under a PSA and the government entity is usually the national oil company that holds the government's interest in the PSA. The crucial issue in accounting for tax POB arrangements are if they are akin to a tax holiday or if the upstream entity retains an obligation for the income tax.

POB arrangements that represent a tax holiday such that the upstream company has no legal tax obligation are accounted for as a tax holiday. The upstream company presents no tax expense and does not gross up revenue for the tax paid on its behalf by the government entity. If the upstream company retains an obligation for the income tax, it would follow the accounting described above under Tax paid in cash or in kind.

**1.2.10 Emission trading schemes**

The ratification of the Kyoto Protocol by the EU required total emissions of greenhouse gases within the EU member states to fall to 92% of their 1990 levels in the period between 2008 and 2012. The introduction of the EU Emissions Trading Scheme (EU ETS) on 1 January 2005 represents a significant EU policy response to the challenge. Under the scheme, EU member states have set limits on carbon dioxide emissions from energy intensive companies. The scheme works on a ‘cap’ and ‘trade’ basis and each member state of the EU is required to set an emissions cap covering all installations covered by the scheme.

The EU cap and trade scheme is expected to serve as a model for other governments seeking to reduce emissions.

There are also several non-Kyoto carbon markets in existence. These include the New South Wales Greenhouse Gas Abatement Scheme, the Regional Greenhouse Gas Initiative and Western Climate Initiative in the United States and the Chicago Climate Exchange in North America.

**Accounting for ETS**

The emission rights permit an entity to emit pollutants up to a specified level. The emission rights are either given or sold by the government to the emitter for a defined compliance period.

Schemes in which the emission rights are tradable allow an entity to:

- emit fewer pollutants than it has allowances for and sell the excess allowances;
- emit pollutants to the level that it holds allowances for; or
- emit pollutants above the level that it holds allowances for and either purchase additional allowances or pay a fine.
IFRIC 3 *Emission Rights* was published in December 2004 to provide guidance on how to account for cap and trade emission schemes. The interpretation proved controversial and was withdrawn in June 2005 due to concerns over the consequences of the required accounting because it introduced significant income statement volatility. The withdrawal of IFRIC 3 means there is no specific comprehensive accounting for cap and trade schemes.

The guidance in IFRIC 3 remains valid, but entities are free to apply variations provided that the requirements of all relevant IFRS standards are met. Several approaches have emerged in practice under IFRS. The scheme can result in the recognition of assets (allowances), expense of emissions, a liability (obligation to submit allowances) and potentially a government grant. The allowances are intangible assets and are recognised at cost if separately acquired. Allowances that are received free of charge from the government are recognised either at fair value with a corresponding deferred income (liability), or at cost (nil) as allowed by IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*.

The allowances recognised are not amortised provided residual value is at least equal to carrying value. The cost of allowances is recognised in the income statement in line with the profile of the emissions produced.

The government grant (if initial recognition at fair value under IAS 20 is chosen) is amortised to the income statement on a straight-line basis over the compliance period. An alternative to the straight-line basis can be used if it is a better reflection of the consumption of the economic benefits of the government grant.

The entity may choose to apply the revaluation model in IAS 38 *Intangible Assets* for the subsequent measurement of the emissions allowances. The revaluation model requires that the carrying amount of the allowances is restated to fair value at each balance sheet date, with changes to fair value recognised directly in equity except for impairment, which is recognised in the income statement. This is the accounting that is required by IFRIC 3 and is seldom used in practice.

A provision is recognised for the obligation to deliver allowances or pay a fine to the extent that pollutants have been emitted. The allowances reduce the provision when they are used to satisfy the entity’s obligations through delivery to the government at the end of the scheme year. However, the carrying amount of the allowances cannot reduce the liability balance until the allowances are delivered.

1.3 Company-wide issues

1.3.1 Production sharing agreements and concessions

There are as many forms of production sharing arrangements (PSA) and concessions as there are combinations of national, regional and municipal governments in oil producing areas. A PSA is the method whereby governments facilitate the exploitation of their country’s hydrocarbon resources by taking advantage of the expertise of a commercial oil and gas entity. Governments, particularly in emerging or poorer nations, try to provide a stable regulatory and tax regime to create sufficient certainty for commercial entities to invest in an expensive and long-lived development process. An oil and gas entity will undertake exploration, supply the capital, develop the resources found, build the infrastructure and lift the natural resources. The government retains title to the hydrocarbon resources (whatever the quantity that is ultimately extracted) and often the legal title to all fixed assets constructed to exploit the resources. The government will take a percentage share of the output, which may be delivered in product or paid in cash under an agreed pricing formula. The operating entity may only be entitled to recover specified costs plus an agreed profit margin. It may have the right to extract resources over a specified period of time.

A concession agreement is much the same, although the entity will retain legal title to its assets and does not share production with the government. The government will still be compensated based on production quantities and prices – this is often described as a concession rent, royalty or a tax.

PSAs and concessions are not standard even within the same legal jurisdiction. The more
significant a new field is expected to be, the more likely that the relevant government will write specific legislation or regulations for it. Each must be evaluated and accounted for in accordance with the substance of the arrangement. The entity’s previous experience of dealing with the relevant government will also be important, as it is not uncommon for governments to force changes in PSAs or concessions based on changes in market conditions or environmental factors. An agreement may contain a right of renewal with no significant incremental cost. The government may have a policy or practice with regard to renewal. These should be assessed when estimating the expected life of the agreement.

Exploration, development and production assets in PSAs

The legal form of the PSA or concession should not impact on the recognition of exploration and evaluation (E&E) assets or production assets. Costs that meet the criteria of IFRS 6, IAS 38 or IAS 16 should be recognised in accordance with the usual criteria where the entity is exposed to the majority of the economic risks and has access to the probable future economic benefits of the assets. The period of the PSA or concession should be longer than the expected useful life of the majority of the constructed assets. The probable hydrocarbon resources and current prices should provide evidence that E&E, development and fixed asset investment will be recovered during the concession period. Assets are appropriately recorded on the balance sheet of the entity beyond the E&E phase, if both conditions are present.

A PSA that is shorter than the expected useful life of the related production assets or is a cost plus arrangement can represent an arrangement whereby the government compensates the entity for exploration activities and the development and construction of fixed assets. The entity should assess the arrangement to determine to what extent it is bearing the risks associated with the exploration, the reserves, etc, and to what extent it is instead bearing the risks of contractual performance under the contract. Under arrangements where the entity is largely bearing the risks of its performance under the PSA rather than the risks of the exploration and the reserves, it can continue to capitalise E&E and development costs, but fixed assets are not capitalised as such. The entity instead may have a receivable from the government where it is allowed to retain oil extracted to the extent of costs incurred plus a profit margin. The accounting applied in these circumstances is therefore in accordance with IAS 39 rather than IAS 16.

All assets recognised are then accounted for under the usual policies of the entity for subsequent measurement, depreciation, amortisation, impairment testing and derecognition. Assets should be fully depreciated or amortised on a units of production basis by the date that control passes back to the government or the concession ends. A PSA is almost always a separate CGU for impairment testing purposes once in production.

Revenue and costs of PSAs and concessions

The entity should record only its share of oil under a PSA as revenue. Oil extracted on behalf of a government is not revenue or a production cost. The entity acts as the government’s agent to extract and deliver the oil or sell the oil and remit the proceeds. Many PSAs specify that income taxes owed by the entity are paid in delivered oil rather than cash. ‘Tax oil’ is recorded as revenue and as a reduction of the current tax liability to reflect the substance of the arrangement where the entity delivers oil to the value of its current tax liability. Any volume-based tax is accounted for as royalty or excise tax within operating results.

Assets subject to depreciation, depletion or amortisation should be expensed in a manner that reflects the consumption of their economic benefits. The units of production basis is usually the appropriate method.

1.3.2 Joint ventures

Joint ventures and other similar arrangements are frequently used by oil & gas companies as a way to share the high risks associated with the industry or as a way of bringing in specialist skills to a particular project on an equity basis. The legal basis for a joint venture or the description of it may take various forms; establishing a joint venture might be achieved
through a formal joint venture contract, or alternatively the governance arrangements set out in a company’s constitution might give the same result. The feature that distinguishes a joint venture from other forms of cooperation between parties is the presence of joint control. An arrangement without joint control is not a joint venture.

**Joint control**

Joint control is the contractually-agreed sharing of control. It requires that an identified group of venturers must unanimously agree on all key financial and operating decisions. Put another way – each of those parties that share the joint control have a veto right: they can each block key decisions if they do not agree. Not all parties to the joint venture need to share joint control – it is possible for a small number of key venturers to share joint control, and for other investors to account for their interest either as an investment in an associate (if they have significant influence) or as an available for sale financial asset in accordance with IAS 39.

A key test when identifying if joint control exists is to identify how disputes between ventures are resolved. If joint control exists, resolution of disputes will usually require eventual agreement between the venturers, independent arbitration or, as a last resort, dissolution of the joint venture.

The nomination of one of the venturers as operator of the joint venture does not prevent joint control. The operator’s powers are usually limited to day-to-day operational decisions – all key strategic financial and operating decisions remain with the joint venture partners collectively.

**Types of joint venture**

Joint ventures are analysed into three classes; jointly controlled operations, jointly controlled assets and jointly controlled entities. Jointly controlled assets are common in the upstream industry and jointly controlled entities in the downstream sector. Jointly controlled assets exist when the venturers jointly own and control the assets used in the joint venture. Jointly controlled entities arise when the venturers jointly control an entity which, in turn holds the assets and liabilities of the joint venture. A jointly controlled entity is usually, but not necessarily, a legal entity, such as a company. The key to identifying the presence of an entity is to determine whether the joint venture can perform the functions associated with an entity, such as entering into contracts in its own name, incurring and settling its own liabilities and holding a bank account in its own right.

**Accounting for jointly controlled operations**

Joint operations are often found where one party controls hydrocarbon rights and has production facilities and another party has transport facilities and/or processing capacity. The parties to the joint operation will share the revenue and expenses of the jointly produced end product. Each will retain title and control of its own assets.

The venturer should recognise 100% of the assets it controls and the liabilities it incurs as well as its own expenses and its share of income from the sale of goods or services from the JV.

**Accounting for jointly controlled assets**

A venturer to a jointly controlled assets arrangement recognises:

- its share of the jointly controlled asset, classified according to the nature of the asset;
- any liabilities the venturer has incurred;
- its proportionate share of any liabilities that arise from the jointly controlled assets;
- its share of expenses from the operation of the assets; and
- its share of any income arising from the operation of the assets (for example, ancillary fees from use by third parties).

Jointly controlled assets tend to reflect the sharing of costs and risk rather than the sharing of profits. An example is a joint venture interest in an oil field where each venturer receives its share of the oil produced.

**Accounting for jointly controlled entities**

Jointly controlled entities can be accounted for either by proportionate consolidation or using equity accounting. The choice between these two methods is a policy choice, and must be applied consistently to all jointly controlled...
entities. A key practical issue will sometimes be ensuring that the results of the joint venture are incorporated by the venturer on the same basis as the venturer’s own results – ie, using the same GAAP (IFRS) and the same accounting policy choices. The growing use of IFRS is helping reduce the adjustments required but doesn’t eliminate them.

Companies should be aware, however, that the IASB is proposing to eliminate the choice of proportionate consolidation in certain circumstances. Further details are included in section 2.

Contributions to joint ventures
It is common for venturers to contribute assets to a joint venture when it is created. This may be in the form of cash or a non-monetary asset. Contributions of assets are a part disposal by the contributing party, in return receiving a share of the assets contributed by the other venturers. Accordingly the contributor should recognise a gain/loss on the part disposal measured as the difference between its share of the fair value of the assets contributed by the other venturers and the other venturers’ share of the book value of the asset it contributed.

The venturer recognises its share of an asset contributed by other venturers at its share of the fair value of the asset contributed. This is classified in the balance sheet according to the nature of the asset in the case of jointly controlled assets or when proportionate consolidation is applied to a jointly controlled entity. The equivalent measurement basis is achieved when equity accounting is applied; however, the interest in the asset forms part of the equity accounted investment balance.

The same principles apply when one of the other venturers contributes a business to a joint venture; however, in this case one of the assets recognised will be goodwill, calculated in the same way as in a business combination.

Investments with less than joint control
Some co-operative arrangements may appear to be joint ventures but fail on the basis that unanimous agreement between venturers is not required for key strategic decisions. This may arise when a super majority, for example an 80% majority, is required but where the threshold can be achieved with a variety of combinations of shareholders and no venturers are able to individually veto the decisions of others. Accounting for these arrangements will depend on the way they are structured and the rights that each venturer has.

When the arrangement is organised in an entity, each investor will account for its investment either using equity accounting in accordance with IAS 28 Investments in Associates (if it has significant influence) or at fair value as a financial asset in accordance with IAS 39. When the investors have an undivided interest in the tangible or intangible assets, they will typically have a right to use a share of the operative capacity of that asset. An example is when a number of investors have invested in an oil pipeline and an investor with, say, a 20% interest has the right to use 20% of the capacity of the pipeline. Industry practice is for an investor to recognise its undivided interest at cost less accumulated depreciation and any impairment charges.

An undivided interest in an asset is normally accompanied by a requirement to incur a proportionate share of the asset’s operating and maintenance costs. These costs should be recognised as expenses in the income statement when incurred and classified in the same way as equivalent costs for wholly-owned assets.

Accounting within the joint venture
The preceding paragraphs describe the accounting by the investor in a joint venture. The joint venture itself will normally prepare its own financial statements for reporting to the joint venture partners, for tax compliance or for other reasons. It is increasingly common for these financial statements to be prepared in accordance with IFRS. Joint ventures are typically created by the venturers contributing assets and businesses to the joint venture in exchange for their equity interest in the JV. Assets received by a joint venture in exchange for issuing shares to a venturer is a transaction within the scope of IFRS 2 Share-based Payment. Such assets are therefore recognised at fair value. However, the accounting for the
Receipt of a business contributed by a venturer is not described within the IFRS literature. Two policies have developed. One is to recognise the assets and liabilities of the business, including goodwill, at fair value, similar to the accounting for an asset contribution and the accounting for a business combination. The second is to recognise the assets and liabilities of the business at the same book values as used in the contributing party’s IFRS financial statements. The policy followed must be disclosed and consistently applied.

1.3.3 Business combinations

Acquisition of assets and businesses are common in oil and gas. Entities seek to secure access to reserves or replace depleting reserves. These may be business combinations or acquisitions of groups of assets. IFRS 3 Business Combinations provides guidance on both types of transactions, and the accounting can differ significantly.

All business combinations are accounted for by applying the purchase method. The purchase method is summarised as follows:

a) identify the acquirer;
b) measure the cost of the combination; and
c) record the fair value of assets acquired and liabilities assumed.

Definition of a business

A business is an integrated set of activities managed together to provide a return to investors or other economic benefits. The key element of the definition is ‘integration’. Upstream activities in production will typically represent a business, whereas those at the exploration stage will typically represent a collection of assets. Projects that lie in the development stage will require consideration of the stage of development and other relevant factors.

The accounting for a business combination and a group of assets can be substantially different. A business combination will usually result in the recognition of goodwill and deferred tax. An asset transaction qualifies for the initial recognition exemption and therefore there is usually no deferred tax. The consideration in an asset transaction is allocated to individual assets acquired and liabilities assumed based on relative fair values.

Allocation of the cost of the combination to assets and liabilities acquired

IFRS 3 requires all identifiable assets and liabilities (including contingent liabilities) acquired to be recorded at their fair value. These include assets and liabilities that may not have been previously recorded by the entity acquired eg, acquired reserves and resources – proved, probable and possible.

IFRS 3 also requires recognition separately of intangible assets if they arise from contractual or legal rights, or are separable from the business. The standard includes a list of items that are presumed to satisfy the recognition criteria. The items that should satisfy the recognition criteria include trademarks, trade names, service and certification marks, Internet domain names, customer lists, customer contracts, use rights (such as drilling, water, hydrocarbon, etc), patented/unpatented technology, etc, many of which may apply to oil and gas companies.

Fair values of assets are often determined using discounted cash flow models. These models should include the tax amortisation benefit (TAB) available to the typical market participant. The TAB represents the value associated with the tax deductibility for an asset. Asset values obtained through direct market observations rather than the use of discounted cash flows (DCFs) already reflect the general tax benefit associated with the asset. Differences between the general tax benefit of each asset and the specific tax benefits for the acquirer are included within goodwill because these are entity-specific.

Goodwill

Past practice in upstream transactions accounted for under national GAAP or previous versions of IFRS seldom resulted in the recognition of significant amounts of goodwill. The consideration paid was allocated to proved, probable and possible reserves.

IFRS 3 requires that the fair value of the assets acquired and liabilities assumed are recognised. The difference between consideration and the fair
value of net assets gives rise to positive or negative goodwill. This residual approach to the calculation of goodwill required by IFRS 3 is likely to result in the goodwill in upstream business combinations. Any goodwill is likely to represent the value paid for assets that do not qualify for separate recognition on the balance sheet (such as an assembled workforce), synergies paid for by the acquirer and, occasionally, overpayments.

However, IFRS 3 requires certain assets and liabilities acquired in a business combination to be recognised on a basis other than fair value. Examples include pension liabilities and deferred tax. Deferred tax is calculated after the fair values of the other identifiable assets and liabilities have been determined by comparing the fair value recognised for accounting purposes with the tax base of each asset and liability. Consequently, the mechanics of the deferred tax calculation and the goodwill calculation might result in goodwill being recognised solely as a result of the recognition of the deferred tax. That is, goodwill might be recognised when there is no expectation of goodwill because there are no unrecognised assets, no synergies and no overpayments. This anomaly will persist until the IASB revises the deferred tax standard, expected in 2009.

1.3.4 Functional currency

Oil and gas entities commonly undertake transactions in more than one currency, as commodity prices are often denominated in US dollars and costs are typically denominated in the local currency. Determination of the functional currency can require significant analysis and judgement.

An entity’s functional currency is the currency of the primary economic environment in which it operates. This is the currency in which the entity measures its results and financial position. An entity’s presentation currency is the currency in which it presents its accounts. Reporting entities may select any presentation currency (subject to the restrictions imposed by local regulations or shareholder agreements). However, the functional currency must reflect the substance of the entity’s underlying transactions, events and conditions; it is unaffected by the choice of presentation currency.

Exchange differences can arise for two reasons: when a transaction is undertaken in a currency other than the entity’s functional currency; or when the presentation currency differs from the functional currency.

**Determining the functional currency**

Identifying the functional currency for an oil and gas entity can be complex because there are often significant cash flows in both the US dollar and local currency.

Determining the functional currency, management should take into account primarily the currency that dominates the determination of the sales prices and that most influences operating costs.

The currency in which selling prices are denominated and settled is often the currency that mainly dominates the determination of sales prices, but this is not necessarily the case. Many sales within the oil and gas industry are conducted either in, or with reference to, the US dollar. However, the US dollar may not always be the main influence on these transactions. For many of the commodities sold by oil and gas entities, it is difficult to identify a single country whose competitive forces and regulations mainly determine the selling prices.

If the primary indicators do not provide an obvious answer to what the functional currency is, the currency in which an entity’s finances are denominated should be considered i.e., the currency in which funds from financing activities are generated and the currency in which receipts from operating activities are retained.

A typical oil and gas entity in the production stage receives its revenue predominantly in US dollars with most of its costs denominated in the local currency and only some in US dollars. Management may conclude that the US dollar is the functional currency, as the majority of the cash flows are denominated and settled in the US dollar.

Oil and gas entities at different stages of operation may reach a different view about their functional currency. Functional currency is not a free choice, and an entity’s functional currency does not change unless there are changes in its operations and transaction flows.
Determining the functional currency of holding companies and treasury companies may present some unique challenges; these have largely internal sources of cash although they may pay dividends, make investments, raise debt and provide risk management services. The underlying source of the cash flows to such companies is usually the appropriate basis for determining the functional currency.
2 Developments from the IASB
2 Developments from the IASB

2.1 Extractive activities research project

The extractive activities project at the IASB is a comprehensive research project and the first step towards a standard focused on upstream extractive activities. Any new standard is expected to supersede IFRS 6 Exploration for and Evaluation of Mineral Resources.

The project was approved in 2004 and is considering the unique issues associated with accounting for upstream activities. This involves researching:

- financial reporting issues associated with oil & gas reserves and resources (including the exploration for reserves and resources) – in particular whether and how to define, recognise, measure and disclose reserves and resources; and
- considering other issues related to extractive activity accounting as identified in the IASC’s Extractive Industries Issues Paper.

A Discussion Paper is due in late 2008. Despite the scope of the project including ‘other issues’ and referring to the previous Issues Paper, it is expected to focus almost exclusively on the reserves and resources recognition questions. The Issues Paper spanned a wide range of issues relevant to the industry including decommissioning and restoration, revenue recognition, joint ventures and impairment. The IASB’s discussions to date have raised the possibility of recognising and measuring reserves on the balance sheet at fair value. This will likely be given consideration as one of the possible accounting models during the Board’s deliberations and its public consultations.

2.2 Borrowing costs

The IASB issued amendments to IAS 23 Borrowing Costs in March 2007. IAS 23R removes the policy choice of either capitalising or expensing borrowing costs and requires management to capitalise borrowing costs attributable to qualifying assets. Qualifying assets are assets that take a substantial time to get ready for their intended use or sale. An example is self-constructed assets such as power plant, buildings, machinery.

The changes to the standard were made as part of the IASB’s and FASB’s short-term convergence project. The elimination of the option to expense borrowing costs does not achieve full convergence with US GAAP, as some technical differences remain (for example, definitions of borrowing costs and qualifying assets).

The effective date of IAS 23R is 1 January 2009, with earlier adoption permitted. The amendments are to be applied prospectively; comparatives will not need to be restated. The Board has provided additional relief by allowing management to designate a particular date on which it can start applying the amendments. For example, management can decide to designate 1 October 2008 as a starting date, because the company starts a project for which management would like to capitalise interest when it applies IAS 23R in 2009.

2.3 Emissions Trading Schemes

The IASB added the emissions trading topic to its agenda after the withdrawal of IFRIC 3 Emission Rights in 2005. The project was temporarily deferred (due to deferral of the project relating to government grants) and again activated in December 2007 with the increasing international interest in emission trading schemes and the diversity in practice that has arisen. The Board decided to limit the scope of the project to the issues that arise in accounting for emissions trading schemes, rather than addressing broadly the accounting for all government grants (which would have involved re-activating the IAS 20 project).

The purpose of the project is to comprehensively address the accounting for emissions trading schemes. It will cover the following issues:

- whether the emissions allowances are an asset (considering different ways of acquiring the asset) and what its nature is;
- recognition and measurement of allowances;
- whether liability exists, what its nature is and how it should be measured.

The project is in the research phase, with the Board gathering information on the characteristics of various emissions trading schemes. This will be the basis for preparation of a comprehensive package that outlines the alternative models that
could be used to account for emissions trading schemes. The timing of an initial due process document and the estimated project completion date is not yet determined.

2.4 ED 9 Joint Arrangements

The IASB published in September 2007 the exposure draft ED 9 Joint Arrangements, which sets out proposals for the recognition and disclosure of interests in joint arrangements. It is intended to replace IAS 31 Interests in Joint Ventures and it is another step towards the goals of the Memorandum of Understanding between the IASB and the FASB on the convergence of IFRS and US GAAP. The changes proposed are to IFRS only; there are no changes proposed to US GAAP.

ED 9’s core principle is that parties to a joint arrangement recognise their contractual rights and obligations arising from the arrangement. The ED therefore focuses on the recognition of assets and liabilities by the party to the joint arrangement.

The scope of the ED is broadly the same as that of IAS 31. That is, unanimous agreement is required between the key parties that have the power to make the financial and operating policy decisions for the joint arrangement.

There are two principal changes proposed by ED 9. The first is the elimination of proportionate consolidation for a jointly controlled entity. The second change is the introduction of a ‘dual approach’ to the accounting for joint arrangements.

**Elimination of proportionate consolidation**

Eliminating proportionate consolidation will have a fundamental impact on the income statement and balance sheet for some entities. Entities that currently use proportionate consolidation to account for jointly controlled entities may need to account for many of these using the equity method. These entities will replace the line-by-line proportionate consolidation of the income statement and balance sheet by a single net result and a single net investment balance.

Switching from proportionate consolidation to equity accounting has the following impacts:

- **Revenues are reduced**: the venturer cannot present its share of the joint venture’s revenue as part of its own revenue.
- **Tangible and intangible assets are reduced**: the gross presentation of the venturer’s share of the JV’s tangible assets, intangible assets, other assets and liabilities is replaced by a single net amount, classified as part of its investments.

Although the information about these gross amounts is included in the notes to the financial statements, removing them from the primary statements diminishes their prominence. Moving to equity accounting for an E&P joint venturer also raises the question about the presentation of reserves. Some regulators require that the reserves presented reflect only those that will result in revenue when produced. This accounting change would – in those circumstances – require a restatement of the reserves reported.

**The ‘dual approach’ to joint arrangements**

The second change is the introduction of a ‘dual approach’ to the accounting for joint arrangements. ED 9 carries forward with modification from IAS 31, the three types of joint arrangement; each type having specific accounting requirements. The first two types are Joint Operations and Joint Assets. The description of these types and the accounting for them is consistent with Jointly Controlled Operations and Jointly Controlled Assets in IAS 31. The third type of joint arrangement is a Joint Venture, which is accounted for using equity accounting. A Joint Venture is identified by the party having rights only to a share of the outcome of the joint arrangement, for example a share of the profit or loss of the joint arrangement. The key change is that a single joint arrangement may contain more than one type; for example Joint Assets and a Joint Venture. The party to such a joint arrangement accounts first for the assets and liabilities of the Joint Assets arrangement and then uses a residual approach to equity accounting for the Joint Venture part of the joint arrangement.
The introduction of the dual approach will require all companies to review each of their joint venture agreements. They will need to determine whether each joint arrangement exhibits the properties and characteristics of joint assets/joint operations (typically a direct use of assets/obligation for liabilities) and/or the characteristics of a Joint Venture (an interest in the outcome of the JV, eg, a share of profit generated by the Joint Venture). An interest in the outcome/net result will more commonly arise when the joint arrangement is incorporated; however, unincorporated joint arrangements are capable, in some circumstances, of returning a net result/profit to the partners, and so should also be analysed.

Other considerations

The results presented in financial statements will reflect the cumulative impact of all relevant factors. For example, if a company has an interest in the net result of an E&P joint venture it will account for its interest in the joint venture using equity accounting. However, if it also purchases (its share of) oil from the joint venture and sells it to a third party, it will record revenue for those third-party sales in addition to equity accounting for its interest in the joint venture, after appropriate eliminations.

A company that finds itself moving from proportionate consolidation to equity accounting may also want to consider the impact of its internal management reporting. IFRS 8 Operating Segments requires disclosure of segmental information on the same basis as is provided to the company’s chief operating decision-maker (CODM). The accounting basis used for providing information to the CODM is used to present the segment information in accordance with IFRS 8. Accordingly, if the CODM is presented with information prepared using proportionate consolidation, then this is the basis that should be presented in the segment information and reconciled to the primary financial statements.

The ED includes a number of illustrative examples, including a farm-in arrangement and a unitisation. These examples describe the expected accounting for these arrangements in accordance with the ED proposals. The accounting described in the examples may require some entities to modify their accounting practices in these areas.

Timetable

The IASB expects to publish a new IFRS for joint arrangements in quarter 4 of 2008. The implementation date has not been decided yet but might be as early as 2010. Those companies that conduct a significant amount of their business through joint ventures may want to follow the development of this standard carefully.

2.5 IFRS 3, Business combinations (revised) and IAS 27, Consolidated and separate financial statements (revised)

The IASB issued two revised standards in January 2008: IFRS 3R Business Combinations and IAS 27R Consolidated and Separate Financial Statements. The revised standards are effective for annual periods beginning on or after 1 July 2009. The standards result in more fair value changes being recorded through the income statement and cement the ‘economic entity’ view of the reporting entity.

The key differences between IFRS 3R and IAS 27R and the previous standards are as follows:

- Business combinations achieved by contract alone and business combinations involving only mutual entities are accounted for under the revised IFRS 3.
- Minor changes in the definition of a business with more significant changes in the application guidance.
- Transaction costs incurred in connection with the business combination are expensed when incurred and are no longer included in the cost of the acquiree.
- An acquirer recognises contingent consideration at fair value at the acquisition date. Subsequent changes in the fair value of such contingent consideration will often affect the income statement.
• The acquirer recognises either the entire goodwill inherent in the acquiree, independent of whether a 100% interest is acquired (full goodwill method), or only the portion of the total goodwill that corresponds to the proportionate interest acquired (as currently the case under IFRS 3).

• Any previously-held non-controlling interest (as a financial asset or associate, for example) is remeasured to its fair value at the date of obtaining control, and a gain or loss is recognised in the income statement.

• There are new provisions to determine whether a portion of the consideration transferred for the acquiree or the assets acquired and liabilities assumed are part of the business combination or part of another transaction to be accounted for separately under the applicable IFRS.

• There is new guidance on classification and designation of assets, liabilities and equity instruments acquired or assumed in a business combination on the basis of the conditions that exist at the acquisition date, except for leases and insurance contracts. This guidance includes reassessment of embedded derivatives.

• Intangible assets are recognised separately from goodwill if they are identifiable – i.e., if they are separable or arise from contractual or other legal rights. The reliably-measurable criterion is presumed to be met.

• Recognition of the acquiree’s deferred tax assets after the initial accounting for the business combination leads to an adjustment of goodwill only if the adjustment is made within the measurement period (not exceeding one year from the acquisition date) and the adjustment results from new information about facts and circumstances that already existed at the acquisition date. Otherwise, it must be reflected in the income statement with no change to goodwill.

• All purchases of equity interests from and sales of equity interests to non-controlling interests are treated as treasury share transactions. Any difference between the amount of consideration received or given and the amount of non-controlling interest is recorded in equity. Entities will no longer be able to report gains on the partial disposal of a subsidiary.

• Additional disclosure requirements.

Several of the requirements may be of interest to oil and gas entities. The slight changes in the definition of a business and the related application guidance may push transactions into business combination accounting sooner in the development process. The requirement to re-assess all contracts and arrangements for embedded derivatives may also result in more classified as derivatives with subsequent income statement volatility. Contingent consideration is more common in mining, with selling shareholders seeking to profit from previously undiscovered resources or favourable price movements. These arrangements are less common in oil and gas but do exist. All such arrangements will be captured by the contingent consideration guidance and recognised as liabilities of the acquirer whether or not payment is probable at the date of the transaction. All subsequent changes are income statement items.
3 IFRS/US GAAP Differences
3 IFRS/US GAAP Differences

There are a number of differences between IFRS and US GAAP. This section provides a summary description of those IFRS/US GAAP differences that are particularly relevant to oil & gas entities. These differences relate to: exploration and evaluation, reserves & resources, depreciation, inventory valuation, impairment, disclosure of resources, decommissioning obligations, financial instruments, revenue recognition, joint ventures and business combinations.

3.1 Exploration and evaluation

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capitalisation in the E&amp;E</td>
<td>No formal capitalisation models prescribed. IFRS 6 permits</td>
<td>Two formal models – successful efforts and full cost, in accordance</td>
</tr>
<tr>
<td>evaluation phase</td>
<td>continuation of previous accounting policy for E&amp;E assets but only</td>
<td>with FAS 19 and Regulation S-X Rule 4-10. Types of expenditure that</td>
</tr>
<tr>
<td></td>
<td>until evaluation is complete. Wide range of policies possible from</td>
<td>may be capitalised are defined.</td>
</tr>
<tr>
<td></td>
<td>capitalisation of all E&amp;E expenditures after licence acquisition to</td>
<td></td>
</tr>
<tr>
<td></td>
<td>the expense of all such expenditures. However, changes to</td>
<td></td>
</tr>
<tr>
<td></td>
<td>capitalisation policies are restricted to those which move the policy</td>
<td></td>
</tr>
<tr>
<td></td>
<td>closer to compliance with the IFRS Framework.</td>
<td></td>
</tr>
<tr>
<td>Impairment of E&amp;E assets</td>
<td>IFRS 6 provides specific relief for E&amp;E assets. Cash-generating units</td>
<td>No similar relief for E&amp;E assets. This is unlikely to result in a GAAP</td>
</tr>
<tr>
<td></td>
<td>(CGUs) may be combined up to the level of a segment for E&amp;E assets.</td>
<td>difference when the company uses successful efforts under US GAAP.</td>
</tr>
<tr>
<td></td>
<td>Impairment testing is required immediately before assets are</td>
<td>A company applying full cost will probably be able to shelter</td>
</tr>
<tr>
<td></td>
<td>reclassified from E&amp;E to development.</td>
<td>unsuccessful exploration costs in larger pools until these are depleted</td>
</tr>
<tr>
<td></td>
<td>IFRS 6 also provides guidance in relation to identifying trigger</td>
<td>through production.</td>
</tr>
<tr>
<td></td>
<td>events for an impairment review.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Impairment charges against E&amp;E assets are reversed if recoverable</td>
<td>No reversal of impairment charges is permitted.</td>
</tr>
<tr>
<td></td>
<td>amount subsequently increases.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Evaluation of exploration activity that is completed after the</td>
<td>Evaluation of exploration activity that is completed after the</td>
</tr>
<tr>
<td></td>
<td>balance sheet date and that concludes that the exploration has</td>
<td>balance sheet date and that concludes that the exploration has been</td>
</tr>
<tr>
<td></td>
<td>been unsuccessful, is classified as a non-adjusting (type II)</td>
<td>unsuccessful, is classified as a type I (adjusting) post-balance sheet</td>
</tr>
<tr>
<td></td>
<td>post-balance sheet event.</td>
<td>event (FIN 36).</td>
</tr>
</tbody>
</table>
3.2 Reserves & resources

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Definitions</td>
<td>No system of reserve classification prescribed. No restriction on the categories used for financial reporting purposes.</td>
<td>Entities must use the definitions of reserves and resources approved by the SEC. Only proved reserves can be disclosed for financial reporting purposes. Proved and proved developed are used for depletion depending on the nature of the costs.</td>
</tr>
</tbody>
</table>

3.3 Depreciation of production and downstream assets

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depletion of production assets</td>
<td>The reserve and resource classifications used for the depletion calculation are not specified. An entity should develop an appropriate accounting policy for depletion and apply the policy consistently, eg, unit of production method. Commonly used categories of reserves include proved developed, or proved developed and undeveloped or proved and probable.</td>
<td>The definitions of reserves used are those adopted by the SEC. Proved reserves are used for depletion of acquisition costs and proved developed reserves are used for depletion of development costs.</td>
</tr>
<tr>
<td>Components of property, plant and equipment</td>
<td>Significant parts (components) of an item of PPE are depreciated separately if they have different useful lives. Pool-wide depletion of production assets not permitted.</td>
<td>Cost categories follow major types of assets as required by FAS 19 – individual items are not separated. Production assets held in a full cost pool depleted on a pool-wide basis.</td>
</tr>
</tbody>
</table>

3.4 Inventory valuation issues

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Impact of changes in market prices after balance sheet date</td>
<td>Inventories measured at the lower of cost and net realisable value. Net realisable value does not reflect changes in the market price of the inventory after the balance sheet date if this reflects events and conditions that arose after the balance sheet date.</td>
<td>Inventories measured at the lower of cost and market value. When market value is lower than cost at the balance sheet date, a recovery of market value after the balance sheet date but before the issuance of the financial statements is recognised as a type I (adjusting) post balance sheet event.</td>
</tr>
</tbody>
</table>
## 3.5 Impairment of production and downstream assets

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Impairment test triggers</td>
<td>Assets or groups of assets (cash generating units) are tested for impairment when indicators of impairment are present.</td>
<td>Long-lived assets are tested for impairment only if indicators are present and an undiscounted cash flow test suggests that the carrying amount of an asset will not be recovered from its use and eventual disposal. Unproved properties are assessed periodically for impairment based on results of drilling activity, firm plans, etc.</td>
</tr>
<tr>
<td>Level at which impairment tested</td>
<td>Assets tested for impairment at the cash generating unit (CGU) level. CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Production assets typically tested for impairment at the field level. A pool-wide impairment test is not permitted.</td>
<td>Similar to IFRS except that the grouping of assets is based on largely independent cash flows (in and out) rather than just cash inflows. Production assets accounted for under the full cost method are tested for impairment on a pool-wide basis.</td>
</tr>
<tr>
<td>Measurement of impairment</td>
<td>Impairment is measured as the excess of the asset’s carrying amount over its recoverable amount. The recoverable amount is the higher of its value in use and fair value less costs to sell.</td>
<td>Impairment of proved properties is measured as the excess of the asset’s carrying amount over its fair value. Impairment of unproved properties is based on results of activities.</td>
</tr>
<tr>
<td>Reversal of impairment charge</td>
<td>Impairment losses, other than those relating to goodwill, are reversed when there has been a change in the economic conditions or in the expected use of the asset.</td>
<td>Impairment losses are never reversed.</td>
</tr>
</tbody>
</table>

## 3.6 Disclosure of resources

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disclosure requirements</td>
<td>No specific requirements to disclose reserves and resources; however, IAS 1 includes general requirement to disclose additional information necessary for a fair presentation.</td>
<td>Detailed disclosures required by FAS 69 and SEC Regulation S-X.</td>
</tr>
</tbody>
</table>
### 3.7 Decommissioning obligations

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measurement of liability</td>
<td>Liability measured at the best estimate of the expenditure required to settle the obligation. Risks associated with the liability are reflected in the cash flows or in the discount rate. The discount rate is updated at each balance sheet date.</td>
<td>Range of cash flows prepared and risk weighted to calculate expected values. Risks associated with the liability are only reflected in the cash flows, except for credit risk, which is reflected in the discount rate. The discount rate for an existing liability is not updated. Accordingly, downward revisions to undiscounted cash flows are discounted using the credit adjusted risk-free rate when the liability was originally recognised. Upward revisions, however, are discounted using the current credit adjusted risk-free rate at the time of the revision. Decommissioning liability need not be recognised for assets with indeterminate life.</td>
</tr>
<tr>
<td>Recognition of decommissioning asset</td>
<td>The adjustment to PPE when the decommissioning liability is recognised forms part of the asset to be decommissioned.</td>
<td>The asset recognised in respect of a decommissioning obligation is a separate asset from the asset to be decommissioned. This distinction is relevant because of the limits placed on subsequent adjustments to the asset as a result of remeasurement of the decommissioning liability. In particular, the limit that the decommissioning asset cannot be reduced below zero for US GAAP compared with the limit that the asset to be decommissioned cannot be reduced below zero for IFRS.</td>
</tr>
</tbody>
</table>
3.8 Financial instruments and embedded derivatives

IFRS and US GAAP take broadly consistent approaches to the accounting for financial instruments; however, many detailed differences exist between the two.

IFRS and US GAAP define financial assets and financial liabilities in similar ways. Both require recognition of financial instruments only when the entity becomes a party to the instrument’s contractual provisions. Financial assets, financial liabilities and derivatives are recognised initially at fair value under IFRS and US GAAP. Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are added to its fair value on initial recognition unless the asset or liability is measured subsequently at fair value with changes in fair value recognised in profit or loss. Subsequent measurement depends on the classification of the financial asset or financial liability. Certain classes of financial asset or financial liability are measured subsequently at amortised cost using the effective interest method and others, including derivative financial instruments, at fair value through profit or loss. The Available For Sale (AFS) class of financial assets is measured subsequently at fair value through equity (other comprehensive income). These general classes of financial asset and financial liability are used under both IFRS and US GAAP, but the classification criteria differ in certain respects.

Selected differences between IFRS and US GAAP are summarised below.

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Definition of a derivative</td>
<td>A derivative is a financial instrument:</td>
<td>Sets out similar requirements, except that the terms of the derivative contract should:</td>
</tr>
<tr>
<td></td>
<td>• whose value changes in response to a specified variable or underlying rate (for example, interest rate);</td>
<td>• require or permit net settlement; and</td>
</tr>
<tr>
<td></td>
<td>• that requires no or little net investment; and</td>
<td>• identify a notional amount.</td>
</tr>
<tr>
<td></td>
<td>• that is settled at a future date.</td>
<td>There are therefore some derivatives that may fall within the IFRS definition, but not the US GAAP definition.</td>
</tr>
</tbody>
</table>

Continued on next page
<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Separation of embedded derivatives</td>
<td>Derivatives embedded in hybrid contracts are separated when:</td>
<td>Similar to IFRS except that there are some detailed differences of what is meant by 'closely related'.</td>
</tr>
<tr>
<td></td>
<td>• the economic characteristics and risks of the embedded derivatives are not closely related to the economic characteristics and risks of the host contract;</td>
<td>Under US GAAP, if a hybrid instrument contains an embedded derivative that is not clearly and closely related to the host contract at inception, but is not required to be bifurcated, the embedded derivative is continuously reassessed for bifurcation.</td>
</tr>
<tr>
<td></td>
<td>• a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and</td>
<td>The normal purchases and normal sales exemption cannot be claimed for a contract that contains a separable embedded derivative – even if the host contract would otherwise qualify for the exemption.</td>
</tr>
<tr>
<td></td>
<td>• the hybrid instrument is not measured at fair value through profit or loss.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Under IFRS, reassessment of whether an embedded derivative needs to be separated is permitted only when there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required under the contract.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>A host contract from which an embedded derivative has been separated, qualifies for the own-use exemption if the own-use criteria are met.</td>
<td></td>
</tr>
<tr>
<td>Own-use exemption</td>
<td>Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument are accounted for as financial instruments unless the contract was entered into and continues to be held for the purpose of the physical receipt or delivery of the non-financial item in accordance with the entity's expected purchase, sale or usage requirements.</td>
<td>Similar to IFRS, contracts that qualify to be classified as for normal purchases and normal sales do not need to be accounted for as financial instruments. The conditions under which the normal purchase and normal sales exemption is available is similar to IFRS but detailed differences exist.</td>
</tr>
<tr>
<td></td>
<td>Application of the own-use exemption is a requirement – not an election.</td>
<td>Application of the normal purchases and normal sales exemption is an election.</td>
</tr>
</tbody>
</table>
3.9 Revenue recognition

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overlift/underlift</td>
<td>Revenue is recognised in overlift/underlift situations on a modified entitlements basis.</td>
<td>US GAAP permits a choice of the sales/liftings method or the entitlements method for revenue recognition.</td>
</tr>
</tbody>
</table>

3.10 Joint ventures

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Definition</td>
<td>A joint venture is a contractual agreement that requires all significant decisions to be taken unanimously by all parties sharing control.</td>
<td>A corporate joint venture is a corporation owned and operated by a small group of businesses as a separate and specific business or project for the mutual benefit of the members of the group.</td>
</tr>
</tbody>
</table>
| Types of joint venture | IFRS distinguishes between three types of joint venture:  
• jointly controlled entities – the arrangement is carried on through a separate entity (company or partnership);  
• jointly controlled operations – each venturer uses its own assets for a specific project; and  
• jointly controlled assets – a project carried on with assets that are jointly owned. | Refers only to jointly controlled entities, where the arrangement is carried on through a separate corporate entity. |

Continued on the next page
<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jointly controlled entities</td>
<td>Either the proportionate consolidation method or the equity method is allowed. Proportionate consolidation requires the venturer’s share of the assets, liabilities, income and expenses to be either combined on a line-by-line basis with similar items in the venturer’s financial statements, or reported as separate line items in the venturer’s financial statements.</td>
<td>Prior to determining the accounting model, an entity first assesses whether the joint venture is a Variable Interest Entity (VIE). If the joint venture is a VIE, the primary beneficiary should consolidate. If the joint venture is not a VIE, venturers assess the accounting using the voting interest model. If control does not exist then typically the arrangement will meet the criteria to apply the equity method to measure the investment in the jointly controlled entity. Proportionate consolidation is generally not permitted except for unincorporated entities operating in certain industries, such as the oil &amp; gas industry.</td>
</tr>
</tbody>
</table>
| Contributions to a jointly controlled entity | A venturer that contributes non-monetary assets, such as shares or non-current assets, to a jointly controlled entity in exchange for an equity interest in the jointly controlled entity recognises in its consolidated income statement the portion of the gain or loss attributable to the equity interests of the other venturers, except when:  
- the significant risks and rewards of the contributed assets have not been transferred to the jointly controlled entity;  
- the gain or loss on the assets contributed cannot be measured reliably; or  
- the contribution transaction lacks commercial substance. | Common practice is for an investor (venturer) to record contributions to a joint venture at cost (ie, the amount of cash contributed and the book value of other non-monetary assets contributed). However, sometimes, appreciated non-cash assets are contributed to a newly formed joint venture in exchange for an equity interest when others have invested cash or other financial-type assets with a ready market value. Practice and existing literature in this area vary. Arguments have been put forth that assert that the investor contributing appreciated non-cash assets has effectively realised part of the appreciation as a result of its interest in the venture to which others have contributed cash. Immediate gain recognition can be appropriate. The specific facts and circumstances will affect gain recognition, and require careful analysis. |
### 3.11 Business Combinations

The following summary reflects differences between the requirements of IFRS 3 (Issued 2004) and FAS 141 (Issued 2001).

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Purchase method – fair values on acquisition</strong></td>
<td>Assets, liabilities and contingent liabilities of acquired entity are recognised at fair value where fair value can be measured reliably. Goodwill is recognised as the residual between the consideration paid and the percentage of the fair value of the net assets acquired. In-process research and development is generally capitalised. Liabilities for restructuring activities are recognised only when the acquiree has an existing liability at acquisition date. Liabilities for future losses or other costs expected to be incurred as a result of the business combination cannot be recognised.</td>
<td>There are specific differences from IFRS. Contingent liabilities of the acquiree are recognised if, by the end of the allocation period: • their fair value can be determined, or • they are probable and can be reasonably estimated. Specific rules exist for acquired in-process research and development (generally expensed). Some restructuring liabilities relating solely to the acquired entity may be recognised if specific criteria about restructuring plans are met.</td>
</tr>
<tr>
<td><strong>Purchase method – contingent consideration</strong></td>
<td>Included in cost of combination at acquisition date if adjustment is probable and can be measured reliably.</td>
<td>Generally, not recognised until contingency is resolved and the amount is determinable.</td>
</tr>
<tr>
<td><strong>Purchase method – minority interests at acquisition</strong></td>
<td>Stated at minority’s share of the fair value of acquired identifiable assets, liabilities and contingent liabilities.</td>
<td>Stated at minority’s share of pre-acquisition carrying value of net assets.</td>
</tr>
<tr>
<td><strong>Purchase method – intangible assets with indefinite useful lives and goodwill</strong></td>
<td>Capitalised but not amortised. Goodwill and indefinite-lived intangible assets are tested for impairment at least annually at either the cash-generating unit (CGU) level or groups of CGUs, as applicable.</td>
<td>Similar to IFRS, although the level of impairment testing and the impairment test itself are different.</td>
</tr>
<tr>
<td><strong>Purchase method – negative goodwill</strong></td>
<td>The identification and measurement of acquiree’s identifiable assets, liabilities and contingent liabilities are reassessed. Any excess remaining after reassessment is recognised in the income statement immediately.</td>
<td>Any remaining excess after reassessment is used to reduce proportionately the fair values assigned to non-current assets (with certain exceptions). Any excess is recognised in the income statement immediately as an extraordinary gain.</td>
</tr>
</tbody>
</table>
The revisions made to FAS 141 in 2007 and to IFRS 3 in 2008 remove some of the differences between IFRS and US GAAP. The following table identifies those aspects of business combinations accounting from the table above which will become consistent between IFRS and US GAAP as a result of the revisions to the standards.

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS and US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acquisition method – fair values on</td>
<td>Assets and liabilities of the acquired entity are recognised at fair value. This includes acquired in-process research and development.</td>
</tr>
<tr>
<td>acquisition</td>
<td>Liabilities for restructuring activities are recognised only when the acquiree has an existing liability at the acquisition date.</td>
</tr>
<tr>
<td>Acquisition method – contingent consideration</td>
<td>Contingent consideration recognised at fair value.</td>
</tr>
<tr>
<td>Acquisition method – negative goodwill</td>
<td>The identification and measurement of acquiree’s identifiable assets, liabilities and contingent liabilities are reassessed. Any excess remaining after reassessment is recognised in the income statement immediately.</td>
</tr>
</tbody>
</table>
The following summary reflects differences between the requirements of IFRS 3 (Revised 2008) and FAS 141 (Revised 2007).

<table>
<thead>
<tr>
<th>Issue</th>
<th>IFRS</th>
<th>US GAAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assets and liabilities arising from contingencies</td>
<td>Recognise contingent liabilities at fair value if fair value can be measured reliably. If not within the scope of IAS 39, measure subsequently at higher of amount initially recognised and best estimate of amount required to settle (under IAS 37). Contingent assets are not recognised.</td>
<td>Liabilities and assets subject to contractual contingencies are recognised at fair value. Recognise liabilities and assets subject to other contingencies only if more likely than not that they meet definition of asset or liability at acquisition date. After recognition, retain initial measurement until new information is received, then measure at the higher of amount initially recognised and amount under FAS 5 for liabilities subject to contingencies, and lower of acquisition date fair value and the best estimate of a future settlement amount for assets subject to contingencies.</td>
</tr>
<tr>
<td>Employee benefit arrangements and deferred tax</td>
<td>Measure in accordance with IFRS 2 and IAS 12, not at fair value.</td>
<td>Measure in accordance with FAS 123 and FAS 109, not at fair value.</td>
</tr>
<tr>
<td>Non-controlling interest (NCI) – formerly Minority Interest</td>
<td>Measure at fair value or at NCI share of fair value of identifiable net assets.</td>
<td>Measure at fair value.</td>
</tr>
<tr>
<td>Contingent consideration</td>
<td>If not within scope of IAS 39, account for subsequently under IAS 37. Measure financial asset or liability contingent consideration at fair value, with changes recognised in earnings or other comprehensive income.</td>
<td>Measure subsequently at fair value, with changes recognised in earnings if classified as asset or liability.</td>
</tr>
<tr>
<td>Lessor operating lease assets</td>
<td>Value of asset includes terms of lease.</td>
<td>Value lease separately from asset.</td>
</tr>
</tbody>
</table>
4 Financial disclosure examples
4 Financial disclosure examples

4.1 Exploration & evaluation
Successful Efforts Method

BG Group plc
Exploration expenditure
“BG Group uses the ‘successful efforts’ method of accounting for exploration expenditure. Exploration expenditure, including licence acquisition costs, is capitalised as an intangible asset when incurred and certain expenditure, such as geological and geophysical exploration costs, is expensed. A review of each licence or field is carried out, at least annually, to ascertain whether proved reserves have been discovered. When proved reserves are determined, the relevant expenditure, including licence acquisition costs, is transferred to property, plant and equipment and depreciated on a unit of production basis. Expenditure deemed to be unsuccessful is written off to the income statement. Exploration expenditure is assessed for impairment when facts and circumstances suggest that its carrying amount exceeds its recoverable amount. For the purposes of impairment testing, exploration and production assets may be aggregated into appropriate cash generating units based on considerations including geographical location, the use of common facilities and marketing arrangements.”

Royal Dutch Shell plc
Exploration costs
“Shell follows the successful efforts method of accounting for oil and natural gas exploration costs. Exploration costs are charged to income when incurred, except that exploratory drilling costs are included in property, plant and equipment, pending determination of proved reserves. Exploration wells that are more than 12 months old are expensed unless (a) proved reserves are booked, or (b) (i) they have found commercially producible quantities of reserves, and (ii) they are subject to further exploration or appraisal activity in that either drilling of additional exploratory wells is under way or firmly planned for the near future or other activities are being undertaken to sufficiently progress the assessing of reserves and the economic and operating viability of the project.”

BP plc
Licence and property acquisition costs
“Exploration licence and leasehold property acquisition costs are capitalized within intangible fixed assets and amortized on a straight-line basis over the estimated period of exploration. Each property is reviewed on an annual basis to confirm that drilling activity is planned and it is not impaired. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Upon determination of economically recoverable reserves (‘proved reserves’ or ‘commercial reserves’), amortization ceases and the remaining costs are aggregated with exploration expenditure and held on a field-by-field basis as proved properties awaiting approval within other intangible assets. When development is approved internally, the relevant expenditure is transferred to property, plant and equipment.”

Initial recognition and reclassification out of E&E under IFRS6

“Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to property, plant and equipment.”
Dry Holes

Hydro ASA
Exploration and development costs of oil and gas reserves
“Hydro uses the successful efforts method of accounting for oil and gas exploration and development costs, and is in accordance with IFRS 6 Exploration for and Evaluation of Mineral Resources. Exploratory costs, excluding the cost of exploratory wells and acquired exploration rights, are charged to expense as incurred. Drilling costs for exploratory wells are capitalized pending the determination of the existence of proved reserves. If reserves are not found, the drilling costs are charged to operating expense.”

Annual Report and Accounts 2007, Hydro ASA, p. F12

4.2 Reserves & resources
Estimation of reserves

Royal Dutch Shell plc
Estimation of oil and gas reserves
“Oil and gas reserves are key elements in Shell’s investment decision-making process which is focussed on generating value. They are also an important element in testing for impairment. Changes in proved oil and gas reserves will also affect the standardised measure of discounted cash flows and changes in proved oil and gas reserves, particularly proved developed reserves, will affect unit-of-production depreciation charges to income.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Estimates of oil and gas reserves are inherently imprecise, require the application of judgement and are subject to future revision. Accordingly, financial and accounting measures (such as the standardised measure of discounted cash flows, depreciation, depletion and amortisation charges, and decommissioning and restoration provisions) that are based on proved reserves are also subject to change.

Proved reserves are estimated by reference to available reservoir and well information, including production and pressure trends for producing reservoirs and, in some cases, subject to definitional limits, to similar data from other producing reservoirs. Proved reserves estimates are attributed to future development projects only where there is a significant commitment to project funding and execution and for which applicable governmental and regulatory approvals have been secured or are reasonably certain to be secured. Furthermore, estimates of proved reserves only include volumes for which access to market is assured with reasonable certainty. All proved reserves estimates are subject to revision, either upward or downward, based on new information, such as from development drilling and production activities or from changes in economic factors, including product prices, contract terms or development plans. In general, changes in the technical maturity of hydrocarbon reserves resulting from new information becoming available from development and production activities have tended to be the most significant cause of annual revisions.

In general, estimates of reserves for undeveloped or partially developed fields are subject to greater uncertainty over their future life than estimates of reserves for fields that are substantially developed and depleted. As a field goes into production, the amount of proved reserves will be subject to future revision once additional information becomes available through, for example, the drilling of additional wells or the observation of long-term reservoir performance under producing conditions. As those fields are further developed, new information may lead to revisions.

Changes to Shell’s estimates of proved reserves, particularly proved developed reserves, also affect the amount of depreciation, depletion and amortisation recorded in the Consolidated Financial Statements for property, plant and equipment related to hydrocarbon production activities. These changes can for example be the result of production and revisions.
A reduction in proved developed reserves will increase depreciation, depletion and amortisation charges (assuming constant production) and reduce income.”

Annual Report and Accounts 2007, Royal Dutch Shell plc, p. 122

Disclosure of resources

BG Group plc
(A) Proved reserves
“Proved reserves are the estimated quantities of gas and oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those quantities that are expected to be recovered from new wells on undrilled acreage or from existing wells where relatively major expenditure is required for completion. Proved undeveloped reserves comprise total proved reserves less total proved developed reserves.”

Annual Report and Accounts 2007, BG Group plc, p. 121

4.3 Depreciation of production and downstream assets
Depletion, depreciation and amortisation

BP plc
“Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, field development and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of field development costs takes into account expenditures incurred to date, together with approved future development expenditure required to develop reserves. Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life.”

Annual Report and Accounts 2007, BP plc, p. 102

Depreciation of components

Hydro ASA
“Hydro depreciates separately any component of an item of property, plant and equipment when that component has a useful life and cost that is significant in relation to the total PP&E cost and PP&E useful life. At each financial year-end Hydro reviews the residual value and useful life of our assets, with any estimate changes accounted for prospectively over the remaining useful life of the asset.”

Annual Report and Accounts 2007, Hydro ASA, p. F10

4.4 Impairment

BP plc
Impairment of intangible assets and property, plant and equipment
“The group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If any such indication of impairment exists, the group makes an estimate of its recoverable amount. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cashflows that are largely independent of the cashflows of other groups of assets. An asset group’s recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.”

Annual Report and Accounts 2007, BP plc, p. 103
Value in use

**BP plc**

“Given the nature of the group’s activities, information on the fair value of an asset is usually difficult to obtain unless negotiations with potential purchasers are taking place. Consequently, unless indicated otherwise, the recoverable amount used in assessing the impairment charges described below is value in use. The group generally estimates value in use using a discounted cash flow model. The future cashflows are usually adjusted for risks specific to the asset and discounted using a pre-tax discount rate of 11% (2006 10% and 2005 10%). This discount rate is derived from the group’s post-tax weighted average cost of capital. In some cases the group’s pre-tax discount rate may be adjusted to account for political risk in the country where the asset is located.”

*Annual Report and Accounts 2007, BP plc, p. 121*

**Royal Dutch Shell plc**

“Estimates of future cash flows used in the evaluation for impairment of assets related to hydrocarbon production are made using risk assessments on field and reservoir performance and include outlooks on proved reserves and unproved volumes, which are then riskweighted utilising the results from projections of geological, production, recovery and economic factors.

Estimates of future cash flows are based on management estimates of future commodity prices, market supply and demand, product margins and, in the case of oil and gas properties, the expected future production volumes. Other factors that can lead to changes in estimates include restructuring plans and variations in regulatory environments. Expected future production volumes, which include both proved reserves as well as volumes that are expected to constitute proved reserves in the future, are used for impairment testing because Shell believes this to be the most appropriate indicator of expected future cash flows, used as a measure of value in use. Estimates of future cash flows are risk-weighted to reflect expected cash flows and are consistent with those used in subsidiaries’ business plans. A discount rate based on Shell’s marginal cost of debt is used in impairment testing. Expected cash flows are then risk-adjusted to reflect specific local circumstances or risks surrounding the cash flows. Shell reviews the discount rate to be applied on an annual basis although it has been stable in recent years.”

*Annual Report and Accounts 2007, Royal Dutch Shell plc, p. 118 and 123*

Calculation of recoverable amount – Fair value less costs to sell

**Royal Dutch Shell plc**

“Other than properties with no proved reserves (where the basis for carrying costs in the Consolidated Balance Sheet is explained under “Exploration costs”), the carrying amounts of major property, plant and equipment are reviewed for possible impairment annually, while all assets are reviewed whenever events or changes in circumstances indicate that the carrying amounts for those assets may not be recoverable. If assets are determined to be impaired, the carrying amounts of those assets are written down to their recoverable amount, which is the higher of fair value less costs to sell and value in use determined as the amount of estimated risk adjusted discounted future cash flows. For this purpose, assets are grouped based on separately identifiable and largely independent cash flows. Assets held for sale are recognised at the lower of the carrying amount and fair value less cost to sell. No further provision for depreciation is charged on such assets.”

*Annual Report and Accounts 2007, Royal Dutch Shell plc, p. 118*
4.5 Decommissioning obligation
Revisions to decommissioning provisions

BG Group plc
Decommissioning costs
“Where a legal or constructive obligation has been incurred, provision is made for the net present value of the estimated cost of decommissioning at the end of the producing lives of fields. When this provision gives access to future economic benefits, an asset is recognised and then subsequently depreciated in line with the life of the underlying producing field, otherwise the costs are charged to the income statement. The unwinding of the discount on the provision is included in the income statement within finance costs. Any changes to estimated costs or discount rates are dealt with prospectively.

The estimated cost of decommissioning at the end of the producing lives of fields is reviewed at least annually and engineering estimates and reports are updated periodically. Provision is made for the estimated cost of decommissioning at the balance sheet date, to the extent that current circumstances indicate BG Group will ultimately bear this cost. The payment dates of total expected future decommissioning costs are uncertain but are currently anticipated to be between 2010 and 2047.”

Annual Report and Accounts 2007, BG Group plc, p. 74 and 109

Decommissioning provisions

Hydro ASA
Asset retirement obligations and similar liabilities
“Hydro accounts for asset retirement obligations, including decommissioning, restoration and similar liabilities related to the retirement of noncurrent assets under IAS 37 Provisions, Contingent Liabilities and Contingent Assets which prescribes the accounting for obligations associated with the retirement of non-current assets, and IAS 16 Property, plant and equipment. The fair value of the asset retirement obligation is recognized as a liability when it is incurred, and added to the carrying amount of the non-current asset as an element of its cost. The effect of the passage of time on the liability is recognized as an accretion expense, included in Financial expense, and the costs added to the carrying value of the asset are subsequently depreciated over the assets’ useful life. Measurement of an asset retirement obligation requires us to evaluate legal, technical and economic data to determine which activities or sites are subject to asset retirement obligations, as well as the method, cost and timing of such obligations.”

Annual Report and Accounts 2007, Hydro ASA, p. F18

4.6 Financial instruments and embedded derivatives
Scope of IAS 39

BG Group plc
Commodity instruments
“Within the ordinary course of business the Group routinely enters into sale and purchase transactions for commodities. The majority of these transactions take the form of contracts that were entered into and continue to be held for the purpose of receipt or delivery of the commodity in accordance with the Group’s expected sale, purchase or usage requirements. Such contracts are not within the scope of IAS 39.

Certain long-term gas sales contracts operating in the UK gas market have terms within the contract that constitute written options, and accordingly they fall within the scope of IAS 39. In addition, commodity instruments are used to manage certain price exposures in respect of optimising the timing and location of its physical gas and LNG commitments. These contracts are recognised on the balance sheet at fair value with movements in fair value recognised in the income statement, see Presentation of results above, note 2, page 82, and note 10, page 96.

The Group uses various commodity based derivative instruments to manage some of the risks arising from fluctuations in commodity prices. Such contracts include physical and net settled forwards, futures, swaps and options. Where these derivatives have been designated as cash flow hedges of underlying commodity price
exposures, certain gains and losses attributable to these instruments are deferred in equity and recognised in the income statement when the underlying hedged transaction crystallises.

All other commodity contracts within the scope of IAS 39 are measured at fair value with gains and losses taken to the income statement.

Gas contracts and related derivative instruments associated with the physical purchase and resale of third-party gas are presented on a net basis within other operating income."

4.7 Revenue recognition issues
Revenue recognition – Exchanges

BP plc
“Revenues associated with the sale of oil, natural gas, natural gas liquids, liquefied natural gas, petroleum and chemicals products and all other items are recognized when the title passes to the customer. Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded.”

4.8 Royalty and income taxes
Petroleum taxes

Centrica plc
Petroleum revenue tax (PRT)
“The definitions of an income tax in IAS 12, Income Taxes, have led management to judge that PRT should be treated consistently with other income taxes. The charge for the year is presented within taxation on profit from continuing operations in the Income Statement. Deferred amounts are included within deferred tax assets and liabilities in the Balance Sheet.”
4.9 Emission Trading Schemes
Accounting for ETS

Centrica plc
EU Emissions Trading Scheme and renewable obligations certificates
“Granted CO2 emissions allowances received in a period are initially recognised at nominal value (nil value). Purchased CO2 emissions allowances are initially recognised at cost (purchase price) within intangible assets. A liability is recognised when the level of emissions exceed the level of allowances granted. The liability is measured at the cost of purchased allowances up to the level of purchased allowances held, and then at the market price of allowances ruling at the balance sheet date, with movements in the liability recognised in operating profit. Forward contracts for the purchase or sale of CO2 emissions allowances are measured at fair value with gains and losses arising from changes in fair value recognised in the Income Statement. The intangible asset is surrendered at the end of the compliance period reflecting the consumption of economic benefit. As a result no amortisation is recorded during the period.

Purchased renewable obligation certificates are initially recognised at cost within intangible assets. A liability for the renewables obligation is recognised based on the level of electricity supplied to customers, and is calculated in accordance with percentages set by the UK Government and the renewable obligation certificate buyout price for that period. The intangible asset is surrendered at the end of the compliance period reflecting the consumption of economic benefit. As a result no amortisation is recorded during the period.”

Annual Report and Accounts 2007, Centrica plc, p. 62

4.10 Joint ventures
Accounting for joint ventures

BP plc
Interests in joint ventures
“A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost, plus postacquisition changes in the group’s share of net assets of the jointly controlled entity, less distributions received and less any impairment in value of the investment. Loans advanced to jointly controller entities are also included in the investment on the group balance sheet. The group income statement reflects the group’s share of the results after tax of the jointly controlled entity. The group statement of recognized income and expense reflects the group’s share of any income and expense recognized by the jointly controlled entity outside profit and loss.

Financial statements of jointly controlled entities are prepared for the same reporting year as the group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its jointly controlled entities are eliminated to the extent of the group’s interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in jointly controlled entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs to sell and value in use.
Where the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting on the date from which it no longer has joint control over, or significant influence in the joint venture, or when the interest becomes held for sale.

Certain of the group’s activities, particularly in the Exploration and Production segment, are conducted through joint ventures where the venturers have a direct ownership interest in and jointly control the assets of the venture. The income, expenses, assets and liabilities of these jointly controlled assets are included in the consolidated financial statements in proportion to the group’s interest.”

Annual Report and Accounts 2007, BP plc, p. 100

Accounting for jointly controlled operations

BG Group plc
Basis of consolidation
“The Financial Statements comprise a consolidation of the accounts of the Company and its subsidiary undertakings and incorporate the results of its share of jointly controlled entities and associates using the equity method of accounting. Consistent accounting policies have been used to prepare the consolidated Financial Statements.

Most of BG Group’s Exploration and Production activity is conducted through jointly controlled operations. BG Group accounts for its own share of the assets, liabilities and cash flows associated with these jointly controlled operations using the proportional consolidation method.”

Annual Report and Accounts 2007, BG Group plc, p. 73

Accounting for jointly controlled or owned assets

Hydro ASA
Jointly controlled assets or operations
“Hydro accounts for jointly controlled assets or operations using the proportional method of accounting. In some instances Hydro participates in arrangements, where Hydro and the other partners have a direct ownership in specifically identified assets or direct participation in certain operations of another entity. These jointly controlled assets or operations are accounted for by including Hydro’s percentage ownership share of the assets, liabilities, income and expense on a line-by-line basis in the group financial statements (the proportional method).”

Jointly owned assets or operations
“Hydro accounts for jointly owned assets or operations using the proportional method of accounting. Based on a contractual commitment, Hydro and the other parties to the contract have direct ownership in specifically identified assets or direct participation in certain operations. These jointly owned assets or operations are accounted for by including Hydro’s percentage ownership share of the assets, liabilities, income and expense on a line-by-line basis in the group financial statements (the proportional method).”

Annual Report and Accounts 2007, Hydro ASA, p. F8
Investments with less than joint control

Hydro ASA
Investments in associates and joint ventures
“Associates Hydro accounts for associates using the equity method. The definition of an associate is based on Hydro’s ability to exercise significant influence, which is the power to participate in the financial and operating policies of the entity. Significant influence is assumed to exist if Hydro owns between 20 to 50 percent of the voting rights. However, exercise of judgment may lead to the conclusion of significant influence at ownership levels less than 20 percent or a lack of significant influence at ownership percentages greater than 20 percent. Hydro uses the equity method for a limited number of investees where Hydro owns less than 20 percent of the voting rights, based on an evaluation of the governance structure in each investee.”

Annual Report and Accounts 2007, Hydro ASA, p. F8

4.11 Business combinations
Goodwill

BG Group plc
“Business combinations and goodwill
In the event of a business combination, fair values are attributed to the net assets acquired. Goodwill, which represents the difference between the purchase consideration and the fair value of the net assets acquired, is capitalised and subject to an impairment review at least annually, or more frequently if events or changes in circumstances indicate that the goodwill may be impaired. Goodwill is treated as an asset of the relevant entity to which it relates, including foreign entities. Accordingly, it is re-translated into pounds Sterling at the closing rate of exchange at each balance sheet date.”

Annual Report and Accounts 2007, BG Group plc, p. 73

Allocation of the cost of the combination to assets and liabilities acquired

BP plc
Business combinations and goodwill
“Business combinations are accounted for using the purchase method of accounting. The cost of an acquisition is measured as the cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange, plus costs directly attributable to the acquisition. The acquired identifiable assets, liabilities and contingent liabilities are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the net fair value of the identifiable assets, liabilities and contingent liabilities acquired is recognized as goodwill. Any deficiency of the cost of acquisition below the fair values of the identifiable net assets acquired (i.e. discount on acquisition) is credited to the income statement in the period of acquisition. Where the group does not acquire 100% ownership of the acquired company, the interest of minority shareholders is stated at the minority’s proportion of the fair values of the assets and liabilities recognized. Subsequently, any losses applicable to the minority shareholders in excess of the minority interest on the group balance sheet are allocated against the interests of the parent.
At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination’s synergies. For this purpose, cash-generating units are set at one level below a business segment.
Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired.
Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized.
Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice.

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the group’s share of the net fair value of the identifiable assets. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the goodwill is included within the earnings from jointly controlled entities and associates.”

*Annual Report and Accounts 2007, BP plc, p. 101*

**4.12 Functional currency**  
**Determining the functional currency**

**Royal Dutch Shell plc**

“The functional currency for most upstream companies and for other companies with significant international business is the US dollar, but other companies usually have their local currency as their functional currency. Foreign exchange risk arises when certain transactions are denominated in a currency that is not the entity’s functional currency. Typically these transactions are income/expense or non-monetary item related.”

*Annual Report and Accounts 2007, Royal Dutch Shell plc, p. 145*

The extracts from third-party publications that are contained in this document are for illustrative purposes only; the information in these third-party extracts has not been verified by PricewaterhouseCoopers and does not necessarily represent the views of PricewaterhouseCoopers; the inclusion of a third-party extract in this document should not be taken to imply any endorsement by PricewaterhouseCoopers of that third-party.
Contact us

Global contacts

Richard Paterson
Global Energy, Utilities & Mining Leader
Telephone: +1 713 356 5579
Email: richard.paterson@us.pwc.com

Mark King
Global Oil & Gas IFRS Group
Telephone: +44 20 7804 6878
Email: mark.king@uk.pwc.com

Territory contacts

Africa

Angola
Julian Ince
Telephone: +244 222 395004
Email: julian.ince@ao.pwc.com

Gabon
Elias Pungong
Telephone: +241 77 23 35
Email: elias.pungong@ga.pwc.com

Nigeria
Uyiosa Akpata
Telephone: +234 1 320 2101
Email: uyi.n.akpata@ng.pwc.com

Southern Africa
Stanley Subramoney
Telephone: +27 11 797 4380
Email: stanley.subramoney@za.pwc.com

Asia-Pacific

Australia
Derek Kidley
Telephone: +61 2 8266 9267
Email:derek.kidley@au.pwc.com

China
Gavin Chui
Telephone: +86 10 6533 2188
Email: gavin.chui@cn.pwc.com

India
Nityanand Gupta
Telephone: +91 11 4141 0501
Email: nityanand.gupta@in.pwc.com

Indonesia
William Deertz
Telephone: +62 21 521 3975
Email: william.deertz@id.pwc.com
Europe

Austria
Gerhard Prachner
Telephone: +43 1 501 88 1800
Email: gerhard.prachner@at.pwc.com

Central and Eastern Europe
Peter Mitka
Telephone: +420 251 151 231
Email: peter.mitka@cz.pwc.com

Denmark
Per Timmermann
Telephone: +45 3945 3945
Email: per.timmermann@dk.pwc.com

Finland
Juha Tuomala
Telephone: +358 9 2280 1451
Email: juha.tuomala@fi.pwc.com

France
Philippe Girault
Telephone: +33 1 5657 8897
Email: philippe.girault@fr.pwc.com

Germany
Manfred Wiegand
Telephone: +49 201 438 1517
Email: manfred.wiegand@de.pwc.com

Greece
Socrates Leptis-Bourgi
Telephone: +30 210 687 4693
Email: socrates.leptos-.bourgi@gr.pwc.com

Ireland
Carmel O’Connor
Telephone: +353 1 792 6288
Email: denis.g.oconnor@ie.pwc.com

Italy
John McQuiston
Telephone: +390 6 57025 2439
Email: john.mcquiston@it.pwc.com

Netherlands
Aad Groenenboom
Telephone: +31 26 3712 509
Email: add.groenenboom@nl.pwc.com

Fred Konings
Telephone: +31 70 342 6150
Email: fred.konings@nl.pwc.com

Norway
Ole Schei Martinsen
Telephone: +47 95 26 11 62
Email: ole.martinsen@no.pwc.com

Gunnar Slettebo
Telephone: +47 95 26 11 45
Email: gunnar.slettebo@no.pwc.com

Portugal
Luis Ferreira
Telephone: +351 213 599 296
Email: luis.s.ferreira@pt.pwc.com

Russia & CIS
Dave Gray
Telephone: +7 495 967 6311
Email: dave.gray@ru.pwc.com

Randol Justice
Telephone: +7 495 967 6465
Email: randol.justice@ru.pwc.com

Spain
Francisco Martinez
Telephone: +34 915 684 704
Email: francisco.martinez@es.pwc.com

Sweden
Mats Edvinsson
Telephone: +46 8 555 33706
Email: mats.edvinsson@se.pwc.com

Switzerland
Ralf Schlaepfer
Telephone: +41 58 792 1620
Email: ralf.schlaepfer@ch.pwc.com

United Kingdom
Ross Hunter
Telephone: +44 20 7804 4326
Email: ross.hunter@uk.pwc.com
Middle East

Paul Suddaby
Telephone: +971 4 3043 451
Email: paul.suddaby@ae.pwc.com

The Americas

Canada
John Williamson
Telephone: +1 403 509 7507
Email: john.m.williamson@ca.pwc.com

Alistair Bryden
Telephone: +1 403 509 7354
Email: alistair.e.bryden@ca.pwc.com

Latin America
Jorge Bacher
Telephone: +54 11 4850 6801
Email: jorge.c.bacher@ar.pwc.com

United States
Rich Paterson
Telephone: +1 713 356 5579
Email: richard.paterson@us.pwc.com

Global Accounting Consulting
Services IFRS

Mary Dolson
Telephone: +44 20 7804 2930
Email: mary.dolson@uk.pwc.com

Michael Stewart
Telephone: +44 20 7804 6829
Email: michael.j.stewart@uk.pwc.com

Further information

Olesya Hatop
Global Energy, Utilities & Mining Marketing
Telephone: +49 201 438 1431
Email: olesya.hatop@de.pwc.com