

Financial reporting in the oil and gas industry

International Financial Reporting Standards

3rd edition
19 July 2017



Contents

| | |
|--|-----------|
| Introduction | 11 |
| 1 Oil and gas value chain and significant accounting issues | 12 |
| 2 Upstream activities | 13 |
| 2.1 Overview | 13 |
| 2.2 Reserves and resources | 13 |
| 2.2.1 What are reserves and resources? | 13 |
| 2.2.2 Estimation | 14 |
| 2.3 Exploration and evaluation | 14 |
| 2.3.1 Successful efforts and full cost methods | 14 |
| 2.3.2 Accounting for E&E under IFRS 6 | 15 |
| 2.3.3 Initial recognition of E&E under the IFRS 6 exemption | 16 |
| 2.3.4 Initial recognition under the Framework | 17 |
| Tangible / intangible classification | 18 |
| 2.3.5 Subsequent measurement of E&E assets | 18 |
| 2.3.6 Reclassification out of E&E under IFRS 6 | 18 |
| 2.3.7 Impairment of E&E assets | 19 |
| 2.3.8 Side tracks | 19 |
| 2.3.9 Suspended wells | 20 |
| 2.3.10 Post balance sheet events | 20 |
| Identification of dry holes | 20 |
| License relinquishment | 21 |
| 2.4 Development expenditures | 21 |
| 2.5 Borrowing costs | 22 |
| 2.5.1 Foreign exchange gains and losses | 22 |
| 2.5.2 Hedging instruments | 23 |
| 2.6 Revenue recognition in upstream | 24 |
| 2.6.1 Overlift and underlift | 24 |
| 2.6.2 Pre-production sales | 28 |
| 2.6.3 Forward-selling contracts to finance development | 28 |
| 2.6.4 Provisional pricing arrangements | 29 |

| | | |
|----------|--|-----------|
| 2.6.5 | Long-term contracts | 29 |
| 2.6.6 | Onerous contracts | 29 |
| 2.6.7 | Presentation of revenue | 30 |
| 2.7 | Asset swaps | 31 |
| 2.8 | Depletion, Depreciation and Amortisation (DD&A) | 32 |
| 2.8.1 | UOP basis | 32 |
| 2.8.2 | Change in the basis of reserves | 32 |
| 2.8.3 | Components | 33 |
| 2.9 | Disclosure of reserves and resources | 34 |
| 2.9.1 | Overview | 34 |
| 2.9.2 | Disclosure of E&E and production expenditure | 35 |
| 2.9.3 | SEC rules on disclosure of resources | 35 |
| 3 | Midstream and downstream activities | 37 |
| 3.1 | Overview | 37 |
| 3.2 | Inventory valuation | 37 |
| 3.2.1 | Producers' inventories | 37 |
| 3.2.2 | Broker-dealer inventories | 37 |
| 3.2.3 | Line fill and cushion gas | 38 |
| 3.2.4 | Net realisable value of oil inventories | 39 |
| 3.2.5 | Spare part inventories | 39 |
| 3.3 | Revenue recognition in midstream and downstream operations | 40 |
| 3.3.1 | Product exchanges | 40 |
| 3.3.2 | Oil and gas balances | 40 |
| 3.3.3 | Cost, insurance and freight versus free on board | 41 |
| 3.3.4 | Agency arrangements | 41 |
| 3.3.5 | Tolling arrangements | 42 |
| 3.3.6 | Oilfield services | 42 |
| 3.4 | Emissions trading schemes | 43 |
| 3.4.1 | Accounting for ETS | 43 |
| 3.4.2 | Certified emissions reductions (CERs) | 44 |

| | | |
|----------|--|-----------|
| 3.5 | Depreciation of downstream assets | 45 |
| 3.5.1 | Cost of turnaround/overhaul | 45 |
| 4 | Sector-wide accounting issues | 47 |
| 4.1 | Business combinations | 47 |
| 4.1.1 | Overview | 47 |
| 4.1.2 | Definition of a business | 47 |
| 4.1.3 | Identifying a business combination | 50 |
| 4.1.4 | Acquisition method | 50 |
| | Identifying the acquirer and determining the acquisition date | 50 |
| | Consideration transferred | 50 |
| | Contingent consideration | 50 |
| | Allocation of the cost of the combination to assets and liabilities acquired | 51 |
| | Undeveloped properties / resources | 51 |
| | Tax amortisation benefit | 52 |
| | Key questions | 52 |
| 4.1.5 | Goodwill in O&G acquisitions | 53 |
| | Goodwill and non-controlling interest | 53 |
| | Bargain purchase | 53 |
| 4.1.6 | Deferred tax | 54 |
| | Tax losses | 54 |
| 4.1.7 | Provisional assessments of fair values | 54 |
| 4.1.8 | Business combinations achieved in stages | 55 |
| 4.1.9 | Acquisitions of participating interests in jointly controlled assets | 55 |
| 4.1.10 | Restructuring costs | 57 |
| 4.2 | Joint arrangements | 57 |
| 4.2.1 | Overview | 57 |
| 4.2.2 | Joint control | 57 |
| 4.2.3 | Classification of joint ventures | 57 |
| | Separate vehicles | 58 |
| | Joint arrangements not structured through a separate vehicle | 59 |

| | |
|--|----|
| Joint arrangements structured through a separate vehicle | 59 |
| Rights to assets and obligations for liabilities conferred by legal form | 59 |
| Rights to assets and obligations for liabilities established by contract | 60 |
| Impact of guarantees on classification of a joint arrangement | 61 |
| ‘Other facts and circumstances’ | 61 |
| Re-assessment of classification | 66 |
| 4.2.4 Accounting for joint operations (“JOs”) | 66 |
| 4.2.5 Accounting for joint ventures (“JVs”) | 67 |
| 4.2.6 Contributions to joint arrangements | 67 |
| 4.2.7 Investments with less than joint control | 69 |
| 4.2.8 Changes in ownership in a joint arrangement | 70 |
| Changes in ownership – Joint operations | 70 |
| Changes in ownership – Joint ventures | 71 |
| 4.2.9 Accounting by the joint arrangement | 71 |
| Accounting by the joint venture | 71 |
| Accounting by the joint operation | 72 |
| 4.2.10 Farm outs | 72 |
| Accounting by the farmor | 72 |
| Assets with proven reserves | 72 |
| Assets with no proven reserves | 73 |
| Accounting by the farmee | 73 |
| 4.2.11 Unitisation agreements | 75 |
| 4.3 Production sharing agreements (PSAs) | 77 |
| 4.3.1 Overview | 77 |
| 4.3.2 Entity bears the exploration risk | 78 |
| Cost capitalisation | 78 |
| Revenue recognition | 79 |
| 4.3.3 Entity bears the contractual performance risk | 81 |
| Cost capitalisation criteria | 81 |
| Impairment assessment | 81 |

| | |
|--|-----|
| Revenue recognition | 81 |
| 4.3.4 Decommissioning in PSAs | 82 |
| 4.3.5 Taxes on PSAs | 83 |
| Classification as income tax or royalty | 83 |
| Tax paid in kind | 85 |
| ‘Tax paid on behalf’ (POB) | 85 |
| 4.4 Decommissioning | 85 |
| 4.4.1 Decommissioning provisions | 85 |
| 4.4.2 Revisions to decommissioning provisions | 86 |
| 4.4.3 Deferred tax on decommissioning provisions | 86 |
| 4.4.4 Decommissioning funds | 87 |
| 4.4.5 Termination benefits | 87 |
| 4.5 Impairment of development, production and downstream assets | 88 |
| 4.5.1 Overview | 88 |
| 4.5.2 Impairment indicators | 88 |
| 4.5.3 Cash generating units | 90 |
| 4.5.4 Shared assets | 92 |
| 4.5.5 Fair value less cost of disposal (FVLCOB) | 92 |
| 4.5.6 Value in use (VIU) | 93 |
| Period of projections | 93 |
| Commodity prices in VIU | 93 |
| Foreign currencies in VIU | 94 |
| Assets under construction in VIU | 94 |
| 4.5.7 Interaction of decommissioning provisions and impairment testing | 95 |
| 4.5.8 Goodwill impairment testing | 96 |
| 4.5.9 Impairment reversals | 99 |
| 4.6 Royalties and income taxes | 99 |
| 4.6.1 Petroleum taxes – royalty and excise | 99 |
| 4.6.2 Petroleum taxes based on profits | 99 |
| 4.6.3 Taxes paid in cash or in kind | 102 |

| | | |
|----------|---|------------|
| 4.6.4 | Deferred tax and acquisitions of participating interests in jointly controlled assets | 102 |
| 4.6.5 | Discounting of petroleum taxes | 102 |
| 4.6.6 | Royalties to non-governmental bodies and retained interests | 102 |
| 4.7 | Functional currency | 103 |
| 4.7.1 | Overview | 103 |
| 4.7.2 | Determining the functional currency | 103 |
| 4.7.3 | Change in functional currency | 104 |
| 4.8 | Leasing | 105 |
| 4.8.1 | Overview | 105 |
| 4.8.2 | When does a lease exist? | 105 |
| | Use of specific asset | 105 |
| | Right to use the specific asset | 106 |
| | Reassessment of whether an arrangement contains a lease | 106 |
| 4.8.3 | Accounting for a lease | 106 |
| | Operating lease | 107 |
| | Finance lease | 107 |
| 4.8.4 | Presentation and disclosure | 107 |
| 4.9 | Operating segments | 107 |
| 4.9.1 | Overview | 107 |
| 4.9.2 | What is an operating segment? | 107 |
| 4.9.3 | Identifying operating segments: ‘The management approach’ | 108 |
| 4.9.4 | Aggregation of operating segments | 108 |
| 4.9.5 | Minimum reportable segments | 109 |
| 4.9.6 | Disclosure | 111 |
| 4.10 | Consolidation | 112 |
| 4.10.1 | Control | 112 |
| 5 | Financial instruments, including embedded derivatives | 113 |
| 5.1 | Overview | 113 |
| 5.1.1 | Scope of IAS 39 | 113 |
| 5.1.2 | Application of ‘own use’ | 115 |

| | | |
|----------|--|------------|
| 52 | Measurement of long-term contracts that do not qualify for 'own use' | 116 |
| 5.2.1 | Day-one profits | 117 |
| 5.3 | Volume flexibility (optionality), including 'Take or pay' arrangements | 117 |
| 5.4 | Embedded derivatives | 118 |
| 5.4.1 | Assessing whether embedded derivatives are closely related | 119 |
| 5.4.2 | Timing of assessment of embedded derivatives | 119 |
| 5.5 | LNG contracts | 120 |
| 5.6 | Hedge accounting | 120 |
| 5.6.1 | Principles and types of hedging | 120 |
| 5.6.2 | Cash flow hedges and 'highly probable' | 122 |
| 5.6.3 | Hedging of non-financial Items | 122 |
| 5.6.4 | Reassessment of hedge relationships in business combinations | 122 |
| 5.7 | Centralised trading units | 123 |
| 6 | First time adoption | 125 |
| 6.1 | Deemed cost | 125 |
| 6.2 | Componentisation | 125 |
| 6.3 | Decommissioning provisions | 126 |
| 6.4 | Functional currency | 126 |
| 6.5 | Assets and liabilities of subsidiaries, associates and joint ventures | 127 |
| 6.6 | Financial instruments | 127 |
| 6.7 | Impairment | 127 |
| 6.8 | Borrowing costs | 127 |
| 6.9 | Disclosure requirements | 128 |
| 7 | New standards – IFRS 9, 15 and 16 | 129 |
| 7.1 | IFRS 9 | 129 |
| 7.1.1 | How does classification impact the oil and gas sector? | 130 |
| 7.1.2 | What are the key changes for financial assets? | 130 |
| 7.1.3 | How could current practice change for oil and gas entities? | 131 |
| 7.1.4 | What are the key changes for financial liabilities? | 132 |
| 7.1.5 | Accounting for commodity contracts | 133 |

| | | |
|--------|---|-----|
| 7.1.6 | Hedge accounting | 133 |
| 7.2 | Revenue recognition – IFRS 15 | 134 |
| 7.2.1 | How does it impact the oil and gas sector? | 134 |
| 7.2.2 | Scope | 134 |
| | Definition of a customer | 135 |
| | Production sharing arrangements | 135 |
| | Product exchanges | 135 |
| | Interaction with other standards | 135 |
| 7.2.3 | Oil and gas balances – overlift and underlift | 136 |
| | Scope | 136 |
| | Determining the transaction price | 136 |
| 7.2.4 | Agency relationships | 137 |
| | Principal versus agent considerations | 137 |
| 7.2.5 | Delivery – cost, insurance and freight versus free on board | 138 |
| | Cost, insurance and freight (CIF) | 138 |
| | Free on board (FOB) | 139 |
| 7.2.6 | Provisional pricing arrangements | 139 |
| | Satisfaction of performance obligations | 139 |
| | Determining the transaction price | 139 |
| 7.2.7 | Take-or-pay and similar long-term supply agreements | 140 |
| | Identifying the contract | 140 |
| | Breakages | 140 |
| 7.2.8 | Significant financing elements | 141 |
| 7.2.9 | Disclosures | 141 |
| 7.2.10 | Transition | 142 |
| 7.3 | Leases – IFRS 16 | 142 |
| 7.3.1 | Scope | 142 |
| 7.3.2 | Identifiable asset | 143 |
| 7.3.3 | Determining whether a contract contains a lease | 144 |
| | Interaction between IFRS 15 and IFRS 16 | 148 |

| | | |
|-------|--|-----|
| 7.3.4 | Lease term | 148 |
| 7.3.5 | Recognition and measurement exemptions | 149 |
| 7.3.6 | Lessee accounting | 149 |
| | Initial recognition and measurement | 149 |
| | Lease payments | 150 |
| | Discount rate | 151 |
| | Restoration costs | 151 |
| | Initial direct costs | 152 |
| | Subsequent measurement | 152 |
| | Reassessment | 152 |
| | Modification of a lease | 154 |
| | Decrease in scope | 154 |
| | Increase in scope | 155 |
| | Change in the lease consideration | 156 |
| | Other measurement models | 156 |
| | Presentation and disclosures | 156 |
| 7.3.7 | Lessor accounting | 157 |
| | Modification of a lease | 157 |
| 7.3.8 | Transition | 157 |
| | Acknowledgements | |
| | Contact us | |

Introduction

1. Oil and gas value chain and 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 take 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 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 macroeconomic factors such as commodity prices, currency fluctuations, interest rate risk and political developments. The assessment of commercial viability and technical feasibility to extract 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 and gas value chain: exploration and development, production and sales of product, together with issues that are pervasive to a typical oil and gas entity.

| Upstream activities | Midstream and downstream activities |
|--|---|
| <ul style="list-style-type: none"> • Reserves and resources • Depletion and depreciation of upstream assets • Exploration and evaluation • Development expenditures • Borrowing costs • Revenue recognition • Disclosure of reserves and resources • Production sharing agreements and concessions | <ul style="list-style-type: none"> • Product valuation issues • Revenue recognition issues • Emission trading schemes • Depreciation of downstream assets |

Sector-wide issues:

- Business combinations
- Joint ventures
- Decommissioning
- Impairment
- Royalty and income taxes
- Functional currency
- Leasing
- Financial instruments

2. Upstream activities

2.1 Overview

Upstream activities comprise the exploration for and discovery of hydrocarbons; crude oil and natural gas. They also include the development of these hydrocarbon reserves and resources, and their subsequent extraction (production).

2.2 Reserves and 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 amount and quality of the resources it has the right to extract and sell. Resources are the source of future cash inflows from the sale of hydrocarbons and provide the basis for borrowing and for raising equity finance.

2.2.1 What are reserves and resources?

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.

Natural resources are outside the scope of IAS 16 *Property, plant and equipment* and IAS 38 *Intangible assets*. The IASB is considering the accounting 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 related to the quantity of reserves. The purchase price allocated to reserves acquired in a business combination is the fair value of the reserves and resources at the date of the business combination but only at that point in time.

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; and
- allocation of purchase price in business combinations.

The geological and engineering data available for hydrocarbon 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 associated with their estimated recoverability. These classifications do not arise from any definitions or guidance in IFRS. This publication uses terms as they are commonly used in the industry but there are different specific definitions of reserves, and the determination of reserves is complex.

Several countries have their own definitions of reserves, for example China, Russia, Canada, 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 professional bodies such as the Society of Petroleum Engineers (SPE). Application of different reserve estimation techniques can result in a comparability issue; entities should disclose what definitions they are using and use them consistently.

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.

Section 2.9 discusses disclosure requirements for reserves and resources.

2.2.2 Estimation

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

Preparing reserve estimates 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. It must also take account of operating practices, statutory and regulatory requirements, costs and other factors that will affect the commercial viability of extraction. More information is obtained about the mix of oil, gas, and water, the reservoir pressure, and other relevant data as the field is developed and then enters production. The information is used to update the estimates of recoverable reserves. Estimates of reserves are revised over the life of the field.

2.3 Exploration and evaluation

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 is generally expensed; an exception to this would be separately acquired intangible assets such as payment for an option to obtain legal rights.

The accounting treatment of exploration and evaluation (“E&E”) 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.

2.3.1 Successful efforts and full cost methods

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 of the two methods exist. 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 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 typically 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 have used the full cost method under national GAAP. All costs incurred in searching for, acquiring and developing the reserves in a large geographic cost centre or pool are capitalised. A cost centre or pool is typically a country. The cost pools are then depleted on a country basis as production occurs. If exploration efforts in the country or the geological formation are wholly unsuccessful, the costs are expensed.

Full cost, generally, results in a greater deferral of costs during exploration and development and higher subsequent depletion charges.

Debate continues within the industry on the conceptual merits of both methods although neither is wholly consistent with the IFRS framework. The IASB published IFRS 6 *Exploration for and evaluation of mineral resources* to provide an interim solution for E&E costs pending the outcome of the wider extractive activities project.

The successful efforts method is seen as more compatible with the Framework. Entities transitioning to IFRS can continue applying their current accounting policy for E&E. IFRS 6 does not apply to costs incurred once E&E is completed. The period of shelter provided by the standard is a relatively narrow one, and the componentisation principles of IAS 16 and impairment rules of IAS 36 prevent the continuation of full cost past the E&E phase.

Specific transition relief has been included in IFRS 1 *First-time adoption of IFRSs* to help entities transition from full cost accounting under previous GAAP to successful efforts under IFRS. Further discussion is included in section 6.1.

2.3.2 Accounting 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 para 7]. The entity would have selected a policy under previous GAAP of capitalising or expensing exploration costs. 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 [IFRS 6 para 6-7].

An entity can change its accounting policy for E&E only if the change results in an accounting policy that is closer to the principles of the Framework [IFRS 6 para 13]. 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 criteria used to determine if a policy is relevant and reliable are those set out in paragraph 10 of IAS 8. That is, it must be:

- relevant to decision-making needs of users;
- provide a faithful representation;
- reflect the economic substance;
- neutral (free from bias);
- prudent; and
- complete.

Changes to accounting policy when IFRS 6 first applied

Can an entity make changes to its policy for capitalising exploration and evaluation expenditures when it first adopts IFRS?

Background

Entity A has been operating in the upstream oil and gas sector for many years. It is transitioning to IFRS in 20X5 with a transition date of 1 January 20X4. Management has decided to adopt IFRS 6 to take advantage of the relief it offers for capitalisation of exploration costs and the impairment testing applied.

Entity A has followed a policy of expensing geological and geophysical costs under its previous GAAP. The geological and geophysical studies that entity A has performed do not meet the Framework definition of an asset in their own right, however management has noted that IFRS 6 permits the capitalisation of such costs [IFRS 6 para 9(b)].

Can entity A's management change A's accounting policy on transition to IFRS to capitalise geological and geophysical costs?

Solution

No. IFRS 6 restricts changes in accounting policy to those which make the policy more reliable and no less relevant or more relevant and no less reliable. One of the qualities of relevance is prudence. Capitalising more costs than under the previous accounting policy is less prudent and therefore is not more relevant. Entity A's management should therefore not make the proposed change to the accounting policy.

The above solution is based on entity A being a standalone entity. However, if entity A was a group adopting IFRS and at least one entity in the group had been capitalising exploration and evaluation expenditures, entity A as a group could adopt a policy of capitalisation.

A new entity that has not reported under a previous GAAP and is preparing its initial set of financial statements can choose a policy for exploration cost. Management can choose to adopt the provisions of IFRS 6 and capitalise such costs. This is subject to the requirement to test for impairment if there are indications that the carrying amount of any assets will not be recoverable. The field-by-field approach to impairment and depreciation is applied when the asset moves out of the exploration phase.

2.3.3 Initial recognition of E&E under the IFRS 6 exemption

Virtually all entities transitioning to IFRS have chosen to use the IFRS 6 shelter rather than develop a policy under the Framework.

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. However, IFRS 6 deems these costs to be assets. E&E expenditures might therefore be capitalised earlier than would otherwise be the case under the Framework.

The shelter of IFRS 6 only covers the exploration and evaluation phase, until the point at which the commercial viability of the property, positive or negative, has been established.

2.3.4 Initial recognition 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 findings or further development rights. It is difficult for an entity to demonstrate that the recovery of exploration expenditure is probable. Where entities do not adopt IFRS 6 and instead develop a policy under the Framework, expenditures on an exploration property are expensed until the capitalisation point.

The capitalisation point is the earlier of:

- i) the point at which the fair value less costs to sell of the property can be reliably determined as higher than the total of the expenses incurred and costs already capitalised (such as licence acquisition costs); and
- ii) an assessment of the property demonstrates that commercially viable reserves are present and hence there are probable future economic benefits from the continued development and production of the resource.

Cost of survey that provides negative evidence of resources but results in increase in the fair value of the license – Should they be capitalised?

Background

Entity B operates in the upstream oil and gas sector and has chosen to develop accounting policies for exploration and evaluation expenditures that are fully compliant with the requirements of the IFRS Framework rather than continue with its previous accounting policies. It also chooses not to group exploration and evaluation assets with producing assets for the purposes of impairment testing.

Entity B has acquired a transferable interest in an exploration licence. Initial surveys of the licence area already completed indicate that there are hydrocarbon deposits present but further surveys are required in order to establish the extent of the deposits and whether they will be commercially viable.

Management are aware that third parties are willing to pay a premium for an interest in an exploration licence if additional geological and geophysical information is available. This includes licences where the additional information provides evidence of where further surveys would be unproductive.

Question

Can entity B capitalise the costs of a survey if it is probable before the survey is undertaken that the results of the survey will increase the fair value of the licence interest regardless of the survey outcome?

Solution

Yes. Entity B may capitalise the costs of the survey provided that the carrying amount does not exceed recoverable amount. Entity B's management are confident before the survey is undertaken that the increase in the fair value less costs to sell of the licence interest will exceed the cost of the additional survey. Capitalisation of the costs of the survey therefore meets the accounting policy criteria set out by the entity.

Costs incurred after probability of economic feasibility is established are capitalised only if the costs are necessary to bring the resource to commercial production. Subsequent expenditures should not be capitalised after commercial production commences, unless they meet the asset recognition criteria.

Tangible/Intangible classification

Exploration and evaluation assets recognised should be classified as either tangible or intangible according to their nature [IFRS 6 para 15]. A test well, however, is normally considered to be a tangible asset. The classification of E&E assets as tangible or intangible has a particular consequence if the revaluation model is used for subsequent measurement (although this is not common) or if the fair value as deemed cost exemption in IFRS 1 is used on first-time adoption of IFRS.

The revaluation model can only be applied to intangible assets if there is an active market in the relevant intangible assets. This criterion is rarely met and would never be met for E&E assets as they are not homogeneous. The 'fair value as deemed cost' exemption in IFRS only applies to tangible fixed assets and thus is not available for intangible assets. Classification as tangible or intangible may therefore be important in certain circumstances.

However, different approaches are widely seen in practice. Some companies will initially capitalise exploration and evaluation assets as intangible and, when the development decision is taken, reclassify all of these costs to oil and gas properties within property, plant and equipment. Some capitalise exploration expenditure as an intangible asset and amortise this on a straight line basis over the contractually-established period of exploration. Others capitalise exploration costs as tangible within construction in progress or PP&E from commencement of the exploration.

Clear disclosure of the accounting policy chosen and consistent application of the policy chosen are important to allow users to understand the entity's financial statements.

2.3.5 Subsequent measurement of E&E assets

Exploration and evaluation assets can be measured using either the cost model or the revaluation model as described in IAS 16 and IAS 38 after initial recognition [IFRS 6 para 12]. In practice, most companies use the cost model.

Depreciation and amortisation of E&E assets usually does not commence until the assets are placed in service. Some entities choose to amortise the cost of the E&E assets over the term of the exploration license.

2.3.6 Reclassification out of E&E under IFRS 6

E&E assets are reclassified from Exploration and Evaluation when evaluation procedures have been completed [IFRS 6 para 17]. E&E assets that are not commercially viable are written down.

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 [IFRS 6 para 17]. The impairment testing requirements are described below.

Once an E&E asset has been reclassified from E&E, it is subject to the normal IFRS requirements. This includes impairment testing at the CGU level and depreciation on a component basis. The relief provided by IFRS applies only to the point of evaluation (IFRIC Update November 2005).

An E&E asset for which no commercially-viable reserves have been identified should be written down to its fair value less costs to sell. The E&E asset can no longer be grouped with other producing properties.

2.3.7 Impairment of E&E assets

IFRS 6 introduces an alternative impairment-testing regime for E&E assets. An entity assesses E&E assets for impairment only when there are indicators that 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.
- A 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.

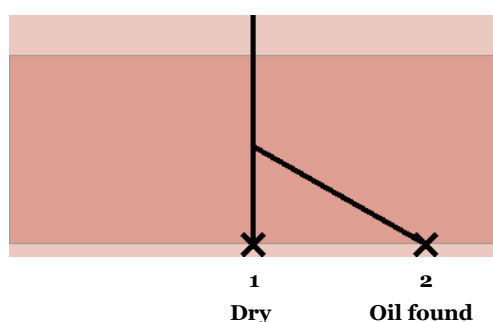
The affected E&E assets are tested for impairment once indicators have been identified. IFRS introduces a notion of larger cash generating units (CGUs) for E&E assets. Entities are allowed to group E&E assets with producing assets, as long as the policy is applied consistently and is clearly disclosed. Each CGU or group of CGUs cannot be larger than an operating segment (before aggregation). The grouping of E&E assets with producing assets might therefore enable an impairment to be avoided for a period of time.

2.3.8 Side tracks

Performing exploratory drilling at a particular location can indicate that reserves are present in a nearby location rather than the original target. It may be cost-effective to “side track” from the initial drill hole to the location of reserves instead of drilling a new hole. If this side track is successful in locating reserves, the cost previously incurred on the original target can remain capitalised instead of being written off as a dry hole. The additional costs of the side track are treated in accordance with the company’s accounting policy which should be followed consistently. The asset should be considered for impairment if the total cost of the asset has increased significantly. If the additional drilling is unsuccessful, all costs would be expensed.

Costs of side tracks – Should they be expensed?

Background



An entity is drilling a new well in the development phase. It has drilled to spot 1, incurring costs of \$5 million, but no reserves were found. Based on test data from the drilling, and a geological study, an alternative drill target was identified (spot 2). The entity could side track to this from a point in the existing drill hole instead of drilling an entirely new well. Reserves were found at spot 2.

Question

How much cost should entity’s management write off?

Solution

No costs will be written off as the drilling has proved successful.

2.3.9 Suspended wells

Exploratory wells may be drilled and then suspended or a well's success may not be determined at the point drilling has been completed. The entity may decide to drill another well and subsequently recommence work on the suspended well at a later date. A question arises as to the treatment of the costs incurred on the original drilling: should these be written off or remain capitalised? The intention of the entity to recommence the drilling process is critical. If the entity had decided to abandon the well, the costs incurred should be written off. However, in cases where there is an intention to recommence work on the suspended well at a later date, the related costs may remain capitalised.

FASB ASC-932 *Extractive Activities – Oil and Gas* includes guidance on whether to expense or defer exploratory well costs when the well's success cannot be determined at the time of drilling. Capitalised drilling costs can continue to be capitalised when the well has found a sufficient quantity of reserves to justify completion as a producing field and sufficient progress is being made in assessing the reserves and viability of the project. If either criterion is not met, or substantial doubt exists about the economic or operational viability of the project, the exploratory well costs are considered impaired and are written off. Costs should not remain capitalised on the basis that current market conditions will change or technology will be developed in the future to make the project viable. Long delays in assessment or development plans raise doubts about whether sufficient progress is being made to justify the continued capitalisation of exploratory well costs after completion of drilling.

IFRS does not contain specific guidance on measurement of costs for suspended wells. The principles of IFRS 6 would be applied to assess whether impairment has occurred. If the entity intends to recommence drilling or development operations in respect of a suspended well, it may be possible to carry forward these costs in the balance sheet for the same period of time.

2.3.10 Post balance sheet events

Identification of dry holes

An exploratory well in progress at the reporting date may be found to be unsuccessful (dry) subsequent to the balance sheet date. If this is identified before the issuance of the financial statements, a question arises whether this is an adjusting or non-adjusting event.

IAS 10 *Events after the reporting period* requires an entity to recognise adjusting events after the reporting period in its financial statements for the period. Adjusting events are those that provide evidence of conditions that existed at the end of the reporting period. If the condition arose after the reporting period, these would result in non-adjusting events.

Industry practice is varied in this area. An exploratory well in progress at period end which is determined to be unsuccessful subsequent to the balance sheet date based on substantive evidence obtained during the drilling process in that subsequent period could be viewed as a non-adjusting event. These conditions should be carefully evaluated based on the facts and circumstances.

Post balance sheet dry holes – Should the asset be impaired?

Background

An entity begins drilling an exploratory well in October 2010. From October 2010 to December 2010 drilling costs totalling GBP 550,000 are incurred and results to date indicate it is probable there are sufficient economic benefits (i.e. no indicators of impairment). During January 2011 and February 2011, additional drilling costs of GBP 250,000 are incurred and evidence obtained indicates no commercial deposits exist. In the month of March 2011, the well is evaluated to be dry and abandoned. Financial statements of the entity for 2010 are issued on April 2011.

Question

How should the entity account for the exploratory costs in view of the post balance sheet event?

Solution

Since there were no indicators of impairment at period end, all costs incurred up to December 2010 amounting to GBP 550,000 should remain capitalised by the entity in the financial statements for the year ended 31 December, 2010. However, if material, disclosure should be provided in the financial statements of the additional activity during the subsequent period that determined the prospect was unsuccessful.

The asset of GBP 550,000 and costs of GBP 250,000 incurred subsequently in the months of January 2011 to February 2011 would be expensed in the 2011 financial statements.

License relinquishment

Licences for exploration (and development) usually cover a specified period of time. They may also contain conditions relating to achieving certain milestones on agreed deadlines. Often, the terms of the license specify that if the entity does not meet these deadlines, the licence can be withdrawn. Sometimes, entities fail to achieve these deadlines, resulting in relinquishment of the licence. A relinquishment that occurs subsequent to the balance sheet date but before the issuance of the financial statements, must be assessed as an adjusting or non-adjusting event.

If the entity was continuing to evaluate the results of their exploration activity at the end of the reporting period and had not yet decided if they would meet the terms of the licence, the relinquishment is a non-adjusting event. The event did not confirm a condition that existed at the balance sheet date. The decision after the period end created the relinquishment event. If the entity had made the decision before the end of the period that they would not meet the terms of the licence or the remaining term of the licence would not allow sufficient time to meet the requirements then the subsequent relinquishment is an adjusting event and the assets are impaired at the period end. Appropriate disclosures should be made in the financial statements under either scenario.

2.4 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. An entity should develop an accounting policy for development expenditure based on the guidance in IAS 16, IAS 38 and the Framework. Much development expenditure results in assets that meet the recognition criteria in IFRS.

Development expenditures are capitalised to the extent that they are necessary to bring the property to commercial production. Entities should also consider the extent to which abnormal costs have been incurred in developing the asset. IAS 16 requires that the cost of abnormal amounts of labour or other resources involved in constructing an asset should not be included in the cost of that asset. Entities will sometimes encounter difficulties in their drilling plans and make adjustments to these, with the side track issue discussed in section 2.3.8 being one example. There will be a cost associated with this, and entities should develop a policy on how such costs are assessed as being normal or abnormal.

Expenditures incurred after the point at which commercial production has commenced should only be capitalised if the expenditures meet the asset recognition criteria in IAS 16 or 38.

2.5 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. IAS 23 *Borrowing costs* requires that borrowing costs be capitalised in respect of qualifying assets. Qualifying assets are those assets which take a substantial period of time to get ready for their intended use.

Borrowing costs should be capitalised while acquisition or construction is actively underway. These costs include the costs of specific borrowings 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.

Borrowing costs incurred during the exploration and evaluation (E&E) phase may be capitalised under IFRS 6 as a cost of E&E if they were capitalising borrowing costs under their previous GAAP. Borrowing costs may also be capitalised on any E&E assets that meet the asset recognition criteria in their own right and are qualifying assets under IAS 23. E&E assets which meet these criteria are expected to be rare.

Entities could develop an accounting policy under IFRS 6 to cease capitalisation of borrowing costs if these were previously capitalised. However, the entity would then need to consider whether borrowing costs relate to a qualifying asset and would therefore require capitalisation. The asset would have to meet the IASB framework definition of an asset and be probable of generating future economic benefit. This definition will not be met for many assets. An exploration licence, for example, would not meet the definition of a qualifying asset as it is available for use in the condition it is purchased and does not take a substantial period of time to get ready for use. Additional exploration expenditure, although it can be capitalised under IFRS 6, would not be considered probable of generating future economic benefit until sufficient reserves are located.

2.5.1 Foreign exchange gains and losses

When development is funded by borrowings in a foreign currency, IAS 21 *The effects of changes in foreign exchange rates* requires any foreign exchange gain or loss to be recognised in the income statement unless they are regarded as adjustments to interest costs, in which case they can be treated as borrowing costs in accordance with IAS 23.

The gains and losses that are an adjustment to interest costs include the interest rate differential between borrowing costs that would be incurred if the entity borrowed funds in its functional currency and borrowing costs actually incurred on foreign currency borrowings.

IAS 23 does not prescribe which method should be used to estimate the amount of foreign exchange differences that may be included in borrowing costs. Two possible methods are:

- The portion of the foreign exchange movement to capitalise may be estimated based on forward currency rates at the inception of the loan.
- The portion of the foreign currency movement to capitalise may be estimated based on interest rates on similar borrowings in the entity's functional currency.

Management must use judgement to assess which foreign exchange differences can be capitalised. The method used is a policy choice which should be applied consistently to foreign exchange differences whether they are gains or losses.

Exchange differences on foreign currency borrowings

Background

An upstream oil and gas entity domiciled in the UK, with GBP functional currency, has a US\$1 million foreign currency loan at the beginning of the period. The interest rate on the loan is 4% and is paid at the end of the period. An equivalent borrowing in sterling would carry an interest rate of 6%. The spot rate at the beginning of the year is £1 = US\$1.55 and at the end of the year it is £1 = US\$1.50.

Question

What exchange difference could qualify as an adjustment to the interest cost?

Solution

The expected interest cost on a sterling borrowing would be £645,161 @ 6% = £38,710

| | |
|---|----------------|
| The actual cost of the US\$ loan is: | £ |
| Loan at the beginning of the year: US\$1 million @ 1.55 | 645,161 |
| Loan at the end of the year: US\$1 million @ 1.50 | <u>666,667</u> |
| Exchange loss | 21,506 |
| Interest paid: US\$1 million @ 4% = \$40,000 @ 1.5 | <u>26,667</u> |
| Total | 48,173 |
| Interest on sterling equivalent | <u>38,710</u> |
| Difference | <u>9,463</u> |

The total actual cost of the loan exceeds the interest cost on a sterling equivalent loan by £9,463. Therefore, only £12,043 (£21,506 - £9,463) of the exchange difference of £21,506 may be treated as interest eligible for capitalisation under IAS 23.

The correlation between the exchange rate and interest rate differential should be demonstrable and remain consistent over the life of the borrowing to continue to allow capitalisation of foreign exchange differences.

2.5.2 Hedging instruments

An entity may hedge the cost of purchasing property, plant and equipment or hedge borrowings incurred for the purpose of acquiring or constructing it.

Gains and losses on derivative instruments not designated in an effective hedging relationship under IAS 39 *Financial instruments: recognition and measurement* or IFRS 9 *Financial instruments* should be recognised in income.

The effective portion of hedging gains/losses can only be capitalised as part of the cost of an asset when the hedging instrument qualifies for hedge accounting in accordance with IAS 39 or IFRS 9.

If a hedge of a forecast transaction subsequently results in the recognition of a non-financial asset such as property, plant and equipment, IAS 39 provides a policy choice to adjust the initial cost of the item for the effective portion of the hedging gains or losses (basis adjustment approach) or to recycle such amounts from accumulated other comprehensive income in the same period or periods during which the asset acquired or liability assumed affects profit or loss (such as in the periods that depreciation expense or cost of sales is recognised). For entities that have adopted IFRS 9, the basis adjustment approach would need to be used.

Cash flow hedging relationships may be put in place to hedge interest rate risk or foreign currency risk relating to interest cash flows on borrowings. These hedging relationships would impact the amount of borrowing costs available for the entity to capitalise.

Section 5.6 discusses hedge accounting in further detail.

2.6 Revenue recognition in upstream

Revenue recognition, particularly for upstream activities, can present challenging issues. 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 4.3.2 and 4.3.3.

The IASB issued IFRS 15, the new standard on revenue recognition in May 2014. Refer to section 7.2 for further details.

2.6.1 Overlift and underlift

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

The physical nature of production and transportation of oil is such that it is often more efficient for each partner to lift a full tanker-load of oil. A lifting schedule identifies the order and frequency with which each partner can lift. The amount of oil lifted by each partner at the balance sheet date may not be equal to its working 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 para 14 of IAS 18 *Revenue* 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 [IAS 18 para 9]. Similarly, the overlifter should reflect the purchase of oil at the same value.

Underlift by a partner is an asset in the balance sheet and 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 [IAS 39 para 5]. 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 are 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.

Refer to section 7.2.3 for the potential impact of the new revenue standard on accounting for overlift and underlift.

Overlift and underlift (1)

Recognition of underlift (including net settlement alternative)

How should underlift be accounted for where the imbalance is routinely net settled?

Background

Entity A and entity B jointly control a producing property. A has a 70% interest and B a 30% interest. At the start of the year there is no overlift or underlift.

During the first half of the year, production costs of C7,500 are jointly incurred and 500 barrels of oil are produced. The cost of producing each barrel is therefore C15. There is no production in the second half of the year.

During the first half of the year A has taken 300 barrels and B has taken 200 barrels. Each sold the oil they took at C32 per barrel, the market price at the time. Entity A has underlifted by 50 barrels at year end and B has overlifted by 50 barrels. The market price of a barrel of oil at year end is C35.

The joint venture agreement allows for net cash settlement of the overlift/underlift balance at the market price of oil at the date of settlement. Net settlement has been used by the JV partners in the past.

How should A account for the underlift balance?

Solution

The underlift position represents an amount receivable by A from B in oil or in cash depending on the settlement mechanism selected. The value of the underlift position will change with movements in the oil price. A has the contractual right to demand cash for the underlift balance. The underlift balance is therefore a financial asset (receivable) which should be measured at amortised cost. Amortised cost should reflect A's best estimate of the amount of cash receivable. The best estimate will be the current spot price. The receivable is revised at each balance sheet date to reflect changes in the oil price.

Entity A should recognise a sale to B for the volume that B has overlifted. The substance of the transaction is that A has sold the overlift oil to B at the point of production. The criteria set out in IAS 18 paragraph 14(a)-(e) are met and revenue should therefore be recognised by A.

A's income statement and balance sheet:

| | | Interim, C | | Full year / year end, C |
|--------------------------------|-------------------|---------------|------------------|----------------------------|
| Income statement | | | | |
| Revenue | (500 * C32 * 70%) | 11,200 | | 11,200 |
| Cost of sales | C7,500 * 70% | (5,250) | | (5,250) |
| Gross profit | | 5,950 | | 5,950 |
| Other income / (expense) | | – | (50 * [35 – 32]) | 150 |
| Net income | | 5,950 | | 6,100 |
| Balance sheet (extract) | | | | |
| Underlift receivable | (50 * C32) | 1,600 | (50 * C35) | 1,750 |

Overlift and underlift (2)

Settlement of underlift – net cash settlement

How should the settlement in cash of an underlift be recognised?

Background

Entity A and entity B jointly control a producing property. A has a 70% interest and B a 30% interest. At the start of the year entity A has recognised an underlift balance of 50 barrels, its JV partner, entity B, having overlifted by this amount. The market price of a barrel of oil at the start of the year is C35. The joint venture agreement allows for net cash settlement of the overlift/underlift balance at the market price of oil at the date of settlement. Net settlement has been used by the JV partners in the past.

During the year entity B settles the underlift/overlift balance through a cash payment to A. The oil price at the time of settlement is C37. The cash paid by B to A is therefore C1,850 (= 50 x C37).

How should A reflect the settlement of the underlift balance?

Solution

Entity A should recognise other income of C100. This is the revaluation of the underlift balance to the current market price at the date of settlement. The underlift receivable balance is derecognised when the cash is received.

The entries required at the date of settlement are:

| | Dr, C | Cr, C |
|---|-------|-------|
| Dr Underlift (50 * [C37 – C35]) | 100 | |
| Cr Other income | | 100 |
| Being restatement of underlift to current market price | | |
| Dr Cash | 1,850 | |
| Cr Underlift | | 1,850 |
| Being derecognition of underlift balance on cash settlement | | |

Overlift and underlift (3)

Settlement of overlift – physical settlement (including net settlement alternative)

How should the physical settlement of an overlift balance be recognised when net cash settlement is an alternative?

Background

Entity A and entity B jointly control a producing property. A has a 70% interest and B a 30% interest. At the start of the year entity B has recognised an overlift balance of 50 barrels, its JV partner, entity A, having underlifted by this amount. The market price of a barrel of oil at the start of the year is C30.

The joint venture agreement allows for net cash settlement of the overlift/underlift balance at the market price of oil at the date of settlement. Net settlement has been used by the JV partners in the past.

During the year A and B agree to settle the overlift balance through A taking more than its share of the oil produced during the period. The oil price at the time of settlement is C32.

During the first half of the year, production costs of C7,500 are jointly incurred and 500 barrels of oil produced. The cost of producing each barrel is therefore C15. There is no production in the second half of the year.

During the first half of the year A has taken 400 barrels and B has taken 100 barrels. Each sold the oil they took at C32 per barrel, the market price at the time. Entity A has therefore overlifted during the year by 50 barrels and B has underlifted by 50 barrels.

At year end there is no underlift/overlift balance. The market price of a barrel of oil at year end is C35.

How should B reflect the settlement of the overlift balance?

Solution

Entity B should recognise a sale to A for the volume that A has overlifted. The substance of the transaction is that B has sold the overlift oil to A at the point of production. The criteria set out in IAS 18 (revised) paragraph 14(a)-(e) are met and revenue should therefore be recognised.

Entity B's overlift balance at the start of the year is revalued to current market value when the balance is settled through A overlifting from B. The increase in overlift value is recognised as other expense.

B's income statement and balance sheet:

| | | Interim, C | Full year / year end, C |
|-----------------------------|----------------------|------------|----------------------------|
| Income statement | | | |
| Revenue | $(500 * C32 * 30\%)$ | 4,800 | 4,800 |
| Cost of sales | $(C7,500 * 30\%)$ | (2,250) | (2,250) |
| Gross profit | | 2,550 | 2,550 |
| Other income / (expense) | $(50 * [C32 - C30])$ | (100) | (100) |

| | | |
|--------------------------------|-------|-------|
| Net income | 2,450 | 2,450 |
| Balance sheet (extract) | | |
| Underlift | – | – |

2.6.2 Pre-production sales

An entity may produce test oil from a development well prior to entering full production. This test oil may be sold to third parties. Where the test oil is considered necessary to the completion of the asset, the proceeds from sales are usually offset against the asset cost instead of being recognised as revenue within the income statement.

In June 2017 an ED was issued proposing a narrow-scope amendment to IAS 16 to prohibit the deduction of proceeds from the cost of PPE. These proceeds would be recognised as revenue and related costs as expenses within the income statement.

2.6.3 Forward-selling contracts to finance development

Oil and gas exploration and development is a capital intensive process and different financing methods have arisen. A Volumetric Production Payment (VPP) arrangement is a structured transaction that involves the owner of oil or gas interests selling a specific volume of future production from specified properties to a third party investor for cash. The owner is then able to use this cash to fund the development of a promising prospect. VPPs come in many different forms and each needs to be carefully analysed to determine the appropriate accounting. The buyer in a VPP may assume significant reserve and production risk and all, or substantially all, of the price risk. If future production from the specified properties is inadequate, the seller has no obligation to make up the production volume shortfall. Legally, a VPP arrangement is considered a sale of an oil or gas interest because ownership of the reserves in the ground passes to the buyer. The only specific guidance for a VPP arrangement is found in US GAAP. However, as the US GAAP requirements are consistent with the principles of IFRS many IFRS entities would follow this guidance.

The seller in a VPP arrangement will deem that it has sold an oil and gas interest. Common practice would be to eliminate the related reserves for disclosure purposes. However, typically a gain is not recognised upon entering the arrangement because the seller remains obligated to lift the VPP oil or gas reserves for no future consideration.

The seller records deferred revenue for all of the proceeds received in these circumstances and does not reduce the carrying amount of PP&E related to the specified VPP properties. The amount received is recorded as deferred revenue rather than a loan as the intention is that the amount due will be settled in the commodity rather than cash or a financial asset. Sometimes such contracts (subject to the terms relating to volume flexibility and pricing formula) have embedded derivatives in them which require separation (see sections 5.3 and 5.4 for discussions on volume flexibility and embedded derivatives).

If no gain is recognised the seller will recognise the deferred revenue and deplete the carrying amount of PP&E related to the specified VPP properties as oil or gas is delivered to the VPP buyer. No production would be shown in the supplemental disclosures in relation to the VPP. The revenue arising from the sale under the VPP contract is recognised over the production life of the VPP.

This is a complex area and these transactions occur infrequently. There will be very specific facts for each arrangement. These must be understood and analysed as small changes in contractual arrangements may result in different accounting treatments.

IFRS 15, the new revenue standard effective on 1 January 2018, might mean a significant change from current accounting practice for alternative financing arrangements. The complexity of these

structures means that careful analysis will be required by the sellers before reaching a conclusion on the appropriate accounting.

2.6.4 Provisional pricing arrangements

Sales contracts for certain commodities often incorporate provisional pricing – at the date of delivery of the oil or gas, a provisional price may be charged. The final price is generally an average market price for a particular future period.

Revenue from the sale of provisionally priced commodities is recognised when risks and rewards of ownership are transferred to the customer, which would generally be the date of delivery. The amount of revenue to be recognised will be estimated based on the forward market price of the commodity being sold.

The provisionally priced contracts are marked to market at each reporting date with any adjustments being recognised within revenue.

Refer to section 7.2.6 for the potential impact of the new revenue standard on accounting for provisional pricing arrangements.

2.6.5 Long-term contracts

Long-term sales contracts are common in the oil and gas industry. Producers and customers may enter into long-term sales contracts to secure supply and reasonable pricing arrangements. Such contracts are sometimes fundamental to the development and continuation of an oil and gas entity and will be the basis on which the decision is made to proceed to the production stage and impact the certainty of cash flows upon which financing may depend. Sales under long-term contracts are accounted for under the principles previously discussed, but other considerations may also arise.

Contracts will typically stipulate a set volume of product over the period at an agreed price. There are often clauses within the contract relating to price adjustment or escalation over the course of the contract to protect the producer and/or the seller from significant changes to the underlying assumptions in place at the time the contract was signed. Prices may vary based on world market prices, cost escalation or some other form of price index (section 2.6.4 above). These features or other contractual terms may give rise to embedded derivatives (see section 5.4).

Contracts may also allow for changes in quantity or timing of deliveries, and may or may not provide for compensatory arrangements for either party if circumstances change. Producers may also agree to variations notwithstanding any legally enforceable rights. Such contracts may contain embedded derivatives or in certain circumstances permit payment to become receivable in advance of a performance obligation being fulfilled. Certain amounts of revenue may need to be deferred.

Refer to section 7.2.7 for the potential impact of the new revenue standard on accounting for long-term contracts.

2.6.6 Onerous contracts

Many contracts (for example, routine purchase orders) can be cancelled without paying compensation to the other party, and therefore there is no obligation. An onerous contract is defined as a contract in which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it. The unavoidable costs under a contract reflect the least net cost of exiting from the contract, which is the lower of the cost of fulfilling it and any compensation or penalties arising from failure to fulfil it.

The factors which give rise to an onerous contract would likely be an impairment trigger and lead to an impairment assessment under IAS 36 (see section 4.5).

Assessing the appropriate unit of account is important in the evaluation of such contracts. Contracts will be evaluated individually in certain cases (e.g. where an underlying purchase contract or lease of

space is not expected to be needed). Contracts may be factored into the assessment of impairment for the overall cash generating unit in other cases. Considering whether an onerous contract should be provided for is often complex.

For example, an oil and gas company entered into a fixed price long-term supply contract with a customer. The cost of extraction and/or production increases subsequently and the total cost to fulfil the contract is expected to exceed the contract price. An impairment trigger results. The cash flows from this contract will be factored into the value in use or fair value less cost of disposal of the underlying cash generating unit. It is unlikely that an onerous contract would exist in this scenario before the carrying amount of the underlying CGU is zero.

2.6.7 Presentation of revenue

Revenue is defined as the gross inflow of economic benefits that arise in the ordinary course of an entity's activities. Cash flows that do not provide benefit to the entity but are collected on behalf of governments or taxing authorities are conceptually not part of revenue. Oil and gas companies are subject to different types of taxes including income taxes, royalties, excise taxes, duty and similar levies. The prevalence of joint ventures and the variety of different taxes and duties levied on the industry may have resulted in different components of these being included or excluded from the reported revenue amount. This can make it difficult to compare revenue across industry participants.

Section 4.2 *Joint ventures* and 4.3 *Production sharing arrangements and concessions* discuss accounting for these arrangements in more detail. Section 4.6 *Royalty and income taxes* discusses the definition and classification of such items in more detail. The following table sets out the usual treatment for working arrangements and types of taxes that are commonly seen in the industry.

Background

Entity A conducts business through a variety of joint arrangements and is subject to various taxes. These are summarised below.

| Business activity | Income statement presentation | Other comments |
|---|---|---|
| <p>1. Jointly controlled assets:</p> <p>Entity A is responsible for selling its share of the oil produced from the jointly controlled assets.</p> | <p>Recognise revenue earned on the sale of share of oil.</p> | <p>The sales are made by entity A and meet the IAS 18 definition of revenue.</p> |
| <p>2. Jointly controlled entity:</p> <p>The JCE sells the oil produced and entity A receives its share of the profits earned by the JCE. The JCE represents 35% of entity A's operations. Entity A actively participates in the joint management of the JCE. Entity A applies equity accounting to JCEs.</p> | <p>Record share of profit earned by the JCE using equity accounting.</p> <p>Do not record revenue in respect of share of sales made by JCE.</p> | <p>Disclose JCE's revenues in notes to financial statements, together with other summary financial information.</p> |

| Business activity | Income statement presentation | Other comments |
|---|--|---|
| <p>3. Duty on refined product sold</p> <p>Entity A pays a fixed monetary amount per litre of product sold to the government.</p> | <p>The duty should be excluded from the revenue recognised.</p> | <p>The duty does not represent economic benefits receivable by entity A on its own account [IAS 18.8].</p> |
| <p>4. Royalty on product sold</p> <p>Entity A pays in kind 30% of the sales proceeds to the government for each litre of product sold.</p> | <p>The royalty should be excluded from the revenue recognised by the entity [IAS18.8] i.e. if gross sales were C100, and the royalty was C10, the reported revenue would be C90.</p> | <p>The royalty collected by the entity is received on behalf of the government. Entity A is acting as agent for the government.</p> |

2.7 Asset swaps

An entity may exchange part or all of its future production interest in a field for an interest in another field. The fields may be in different stages of development, and depending on how advanced the development is it could be considered to be a business exchange. The accounting requirements will be different if the transaction represents the exchange of assets or a business combination. The properties exchanged may meet the definition of a business; if control is obtained over a property that meets the definition of a business then a business combination has occurred.

An exchange of one non-monetary asset for another is accounted for at fair value unless (i) the exchange transaction lacks commercial substance, or (ii) the fair value of neither of the assets exchanged can be determined reliably. There may be more than one asset or a combination of cash and non-monetary assets. The acquired item is measured at the fair value of assets relinquished unless the fair value of asset or assets received is more readily determinable. A gain or loss is recognised on the difference between the carrying amount of the asset given up and fair value recognised for the asset received. It is expected that the entity will be able to determine a fair value for the assets in many circumstances. There may be some situations where a fair value is not available e.g. there is no market data of recent comparable transactions or exploration and evaluation activity is at an early stage with no conclusive data on reserves and resources. If a fair value cannot be determined the acquired item is measured at cost, which will be the carrying amount of the asset given up. There will be no gain or loss.

An entity determines whether an exchange transaction has commercial substance by considering the extent to which its future cash flows are expected to change as a result of the transaction. IAS 16 provides guidance to determine when an exchange transaction has commercial substance.

If the transaction is determined to be a business combination, the more complex requirements of IFRS 3 apply. An entity may also obtain joint control or significant influence when it acquires an interest in a property through a swap. IFRS 3 requirements apply if an entity acquires an interest in a joint venture that is a business. Otherwise the interest is initially recognised at fair value as determined above and then the requirements of IAS 28 *Investments in associates and joint ventures* apply (as further discussed in section 4.2.7). There can also be situations where entities which own assets or exploration rights in adjacent areas enter into a contract to combine these into a larger area,

effectively an exchange of a share in a small asset for a share in a bigger asset. Section 4.2.11 explores this in more detail.

2.8 Depletion, depreciation and amortisation (DD&A)

This section focuses on the depreciation of upstream assets. The depreciation of downstream assets such as refineries, gas treatment installations, chemical plants, distribution networks and other infrastructure is considered in section 3.5.

The accumulated capitalised costs from E&E and development phases are amortised over the expected total production using a units of production (UOP) basis. UOP is the most appropriate amortisation method because it reflects the pattern of consumption of the reserves' economic benefits. However, straight line amortisation may be appropriate for assets that are consumed more by the passage of time. For example, there may be circumstances when straight line depreciation does not produce a materially different result and can be used rather than UOP.

2.8.1 UOP basis

IFRSs do not prescribe what basis should be used for the UOP calculation. Many entities use only proved developed reserves; others use total proved or both proved and probable. Proved developed reserves are those that can be extracted without further capital expenditure. The basis of the UOP calculation is an accounting policy choice, and should be applied consistently. If an entity does not use proved developed reserves, then an adjustment is made to the calculation of the amortisation charge to include the estimated future development costs to access the undeveloped reserves.

The estimated 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 at the choice of the entity without significant cost.

2.8.2 Change in the basis of reserves

An entity may use one reserves basis for depreciation and subsequently determine that an alternative base may be more appropriate. It may be that the use of proved and probable would be more appropriate as that is the basis management use when assessing their business performance. A change in the basis of reserves from proved reserves to proved and probable reserves (or from proved developed to total proved) is considered acceptable under IFRS.

A change in the basis of reserves constitutes a change in accounting estimate under IAS 8. The entity's policy of depreciating their assets on a UOP basis is unchanged, they have only changed their estimation technique. The effect of the change is recognised prospectively from the period in which the change has been made. Entities which change their UOP basis should ensure that any related changes (such as future capital expenditure to complete any undeveloped assets or access probable reserves) are also incorporated into their depreciation calculation. Appropriate disclosure of the change should be made.

Unit of production calculation – classes of reserves

What class of reserves should be used for the unit of production calculation?

Background

Entity D is preparing its first IFRS financial statements. D's management has identified that it should amortise the carrying amount of its producing properties on a unit of production basis over the reserves present for each field.

However, D's management is debating whether to use proved reserves or proved and probable reserves for the unit of production calculation.

Solution

Entity D's management may choose to use either proved reserves or proved and probable reserves for the unit of production amortisation calculation.

The IASB Framework identifies assets on the basis of probable future economic benefits and so the use of probable reserves is consistent with this approach. However, some national GAAPs have historically required only proved developed reserves be used for such calculations.

Whichever reserves definition D's management chooses it should disclose and apply this consistently to all similar types of production properties. For example, some entities used proved reserves for conventional oil and gas extraction and proved and probable for unconventional properties. If proved and probable reserves are used, then an adjustment must be made to the amortisation base to reflect the estimated future development costs required to access the undeveloped reserves.

2.8.3 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 [IAS 16 para 43-44].

Significant parts of an asset that have similar useful lives and patterns of consumption can be grouped together. This requirement can create complications for oil and gas entities, as there may be 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. The significant components of these types of assets must be separately identified. 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.

The components that have a shorter useful life than the remainder of the asset are depreciated to their 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 [IAS 16 para 13-14].

2.9 Disclosure of reserves and resources

2.9.1 Overview

A key indicator for evaluating the performance of oil and gas entities is their existing reserves and the future production and cash flows expected from them. Some national GAAPs and securities regulators require supplemental disclosure of reserve information, most notably the FASB ASC 932 and Securities and Exchange Commission (SEC) regulations. There have also been recommendations on accounting practices issued by industry bodies such as the UK 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* [IAS 1 para 17] requires that an entity's financial statements should provide additional information when compliance with specific requirements in IFRS is insufficient to enable an entity to achieve a fair presentation.

An entity may consider the pronouncements of other standard-setting bodies and accepted industry practices when developing accounting policies in the absence of specific IFRS guidance. 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 auditor's opinion.

Information about quantities of oil and gas reserves 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 aggregated 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 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 prepare and present '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 investors and other users of financial statements to evaluate.

The disclosure of key assumptions and 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:

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

Other information such as the 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, and the underlying basis clearly disclosed and based on common guidelines or practices, such as the Society of Petroleum Engineers definitions.

2.9.2 Disclosure of E&E and production expenditure

Exploration and development costs that are capitalised should be classified as non-current assets in the balance sheet. They should be separately disclosed in the financial statements and distinguished from producing assets where material [IFRS 6 para 23]. The classification as tangible or intangible established during the exploration phase should be continued through to the development and production phases. Details of the amounts capitalised and the amounts recognised as an expense from exploration, development and production activities should be disclosed.

2.9.3 SEC rules on disclosure of resources

SEC guidance on the disclosure of reserves is viewed by the industry as a best practice approach to disclosure. Oil and gas entities may prepare their reserves disclosures based on this guidance even where they are not SEC-listed. The SEC amended its guidance on disclosure requirements (The Final Rule) and this has been in effect since December 2009.

The main disclosure requirements of the Final Rule are:

- Disclosure of estimates of proved developed reserves, proved undeveloped reserves and total proved reserves. This is to be presented by geographical area and for each country representing 15% or more of a company's overall proved reserves
- Disclosure of reserves from non-traditional sources (i.e. bitumen, shale, coalbed methane) as oil and gas reserves
- Optional disclosure of probable and possible reserves
- Optional disclosure of the sensitivity of reserve numbers to price
- Disclosure of the company's progress in converting proved undeveloped reserves into proved developed reserves. This is to include those that are held for five years or more and an explanation of why they should continue to be considered proved.
- Disclosure of technologies used to establish reserves in a company's initial filing with the SEC and in filings which include material additions to reserve estimates.
- The company's internal controls over reserve estimates and the qualifications of the technical person primarily responsible for overseeing the preparation or audit of the reserves estimates.
- If a company represents that disclosure is based on the authority of a third party that prepared the reserves estimates or conducted a reserves audit or process review, they should also file a report prepared by the third party.

'Oil and gas producing activities' include sources of oil and gas from unconventional sources, including bitumen, oil sands and hydrocarbons extracted from coalbeds and oil shale. Reserve definitions are aligned with those from the Petroleum Resources Management System (PRMS) approved by the Society for Petroleum Engineers (SPE).

The definition of 'proved oil and gas reserves' is "the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions" [Rule 4-10a].

Key criteria to meet this definition are:

- There must be at least a 90% probability that the quantities actually recovered will equal or exceed the stated volume (consistent with PRMS) to achieve the definition of 'Reasonable certainty'.
- The reserves must be 'Economically producible' and this requires the use of average prices during the prior 12-month period.
- To extract the reserves there must be 'Reliable technology': this refers to technology that has been field tested and demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation.

Probable and possible reserve estimates allow the use of deterministic and probabilistic methods.

The Final Rule is silent with respect to the treatment of the reserves of an equity method investment. The ASU, however, requires entities to separately disclose the significant oil and gas producing activities of their equity method investments at the same level of detail as consolidated investments (i.e. including Topic ASC 932 supplemental disclosures).

3. Midstream and downstream activities

3.1 Overview

Midstream and downstream activities in the oil and gas industry include the transportation of crude oil and gas, the refining of crude oil and the sales of the refined products. This part of the value chain is also dependent on significant capital investment. This includes refineries, liquefied natural gas (LNG) facilities, pipeline networks and retail stations. Integrated oil and gas companies might also have divisions that perform speculative trading of oil and gas.

3.2 Inventory valuation

Inventory is usually measured at cost as determined under IAS 2. Various methods are available; specific identification, weighted average or first-in first-out (FIFO). Generally, most entities use cost. In some circumstances inventory of commodities can be valued at net realisable value (NRV) or fair value less costs of disposal (FVLCOB). FVLCOB for commodities is usually equivalent to their NRV. The circumstances in which FVLCOB/NRV can be used are described below.

3.2.1 Producers' inventories

Inventory of minerals and mineral products should be measured at NRV when this is well-established industry practice. [IAS 2 para 3]. It is not usual industry practice for inventories of oil and gas to be measured on this basis, especially by downstream producers. It might however be established practice in certain countries or for commodity trading businesses. Entities operating in those territories might be able to adopt this policy.

Changes in the carrying amount of inventories that are carried at NRV are recognised in the income statement in each period. Determination of NRV reflects the conditions and prices that exist at the balance sheet date. [IAS 2 para 30]. Adjustments are not made to valuations to reflect the time that it will take to dispose of the inventory or the effect that the sale of a significant inventory quantity might have on the market price.

The prices of firm sales contracts are used to calculate NRV only to the extent of the contract quantities, but only if the contracts are not themselves recognised on the balance sheet under another standard, such as IAS 39 or IFRS 9.

3.2.2 Broker-dealer inventories

Inventories held by broker-dealers are measured at FVLCOB. [IAS 2 para 3]. The fair value used is the spot price at the balance sheet date. It is not appropriate to modify the price to reflect a future expected sale by applying a future expected price from a forward price curve.

The definition of broker-trader within IAS 2, and inventories which will fall into this category, is narrow. Items in this category should be principally acquired for the purpose of resale. It is expected that there would be minimal repackaging of such items, and nothing which would change its underlying nature. This requirement can prevent entities from qualifying for the broker-trader exemption if they perform a blending activity, because this changes the chemical composition of the product which is sold. A blending process, for example, might occur not only as part of an entity's deliberate repackaging of a product, but also as a by-product of its storage process. Where an entity wishes to treat its inventory as a broker-trader, careful consideration must be given to whether any activities are performed which would change the nature of the product and therefore prevent it from meeting the requirements of IAS 2.

The carrying amount of inventories that are valued at FVLCOB must be disclosed in the notes. [IAS 2 para 36].

3.2.3 Line fill and cushion gas

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. This product is usually classified as part of the PPE, because it is necessary to bring the PPE to its required operating condition. [IAS 16 para 16(b)]. The product will therefore be recognised as a component of the PPE at cost, and it will be subject to depreciation to estimated residual value.

Product owned by an entity that is stored in PPE owned by a third party is usually classified as inventory. This would include, for example, all gas in a rented storage facility. It does not represent a component of the third party's PPE or a component of PPE owned by the entity. Such product should therefore be measured at FIFO or weighted average cost.

Cushion gas

Should cushion gas be accounted for as PPE or as inventory?

Background

Gaseous Giant SA (GG) is an entity involved in the production and trading of natural gas. GG has purchased salt caverns to use as underground gas storage.

The salt cavern storage is reconditioned to prepare it for injection of gas. The natural gas is injected and as the volume of gas injected increases, so does the pressure. The salt cavern therefore acts as a pressurised container.

The pressure established within the salt cavern is used to push out the gas when it needs to be extracted. When the pressure drops below a certain threshold, there is no pressure differential to push out the remaining natural gas. This remaining gas within the cavern is therefore physically unrecoverable until the storage facility is decommissioned. This remaining gas is known as cushion gas.

Should GG's management account for the cushion gas as PPE or as inventory?

Solution

GG's management should classify and account for the cushion gas as PPE.

The cushion gas is necessary for the cavern to perform its function as a gas storage facility. It is therefore part of the storage facility and should be capitalised as a component of the storage facility PPE asset.

The cushion gas should be depreciated to its residual value over the life of the storage facility in accordance with para 43 of IAS 16. However, if the cushion gas is recoverable in full when the storage facility is decommissioned, depreciation will be recorded against the cushion gas component only if the estimated residual value of the gas decreases below cost during the life of the facility.

When the storage facility is decommissioned and the cushion gas extracted and sold, the sale of the cushion gas is accounted for as the disposal of an item of PPE in accordance with para 68 of IAS 16. Accordingly, the gain/loss on disposal is recognised in profit or loss.

The natural gas in excess of the cushion gas that is injected into the cavern should be classified and accounted for as inventory in accordance with IAS 2.

New leasing standard IFRS 16 is effective on 1 January 2019. Refer to section 7.3.6 for further guidance on lessee accounting.

3.2.4 Net realisable value of oil inventories

Oil produced or purchased for use by an entity is valued at the lower of cost and net realisable value (NRV) unless it is raw product which the entity intends to process to create a new product e.g. refining of crude oil. Determining NRV requires consideration of the estimated selling price in the ordinary course of business less the estimated costs to complete processing and 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. Use of the forward price curve would be appropriate where the entity has an executory contract for the sale of the oil. Movements in the oil price after the balance sheet date typically reflect changes in the market conditions after that date and so they should not be reflected in the calculation of NRV.

NRV of oil inventories

Should NRV for oil inventories at the balance sheet date be calculated using the oil price at the balance sheet date, or should changes in the market price after the balance sheet date be taken into account? In other words, is the decline in the market price an adjusting event?

Background

Entity A is a retailer of oil. It has oil inventories at the balance sheet date. The cost of the oil was C800. Valuing the oil at market price at the balance sheet date, the value is C750. The market price of oil has fallen further since the balance sheet date, and the value of the inventory at the balance sheet date is now C720, based on current prices.

Should entity A calculate NRV for the oil at the balance sheet date using the market value at the balance sheet date, or using the subsequent, lower, price?

Solution

Entity A should calculate the NRV of the oil inventory using the market price at the balance sheet date. The market price of oil changes daily in response to world events. So the changes in the oil price since the balance sheet date reflect events occurring since the balance sheet date. These represent non-adjusting events as defined by IAS 10.

Disclosure of the fall in the price of oil since the balance sheet date, and its potential impact on inventory values, should be made in the financial statements if this is relevant to an understanding of the entity's financial position. [IAS 10 para 2].

If further processing of the inventory is required in order to convert it into a state suitable for sale, the NRV should be adjusted for the associated processing costs.

3.2.5 Spare parts

The plant and machinery used in the refining process can be complex pieces of equipment, and entities usually maintain a store of spare parts and servicing equipment for critical components. These are often carried as inventory and recognised in profit or loss as consumed. Major spare parts, stand-by equipment and servicing equipment can also qualify as property, plant and

equipment when they meet the definition of PP&E. Spare parts in inventory or PP&E should be carried at cost, unless there is evidence of damage or obsolescence.

3.3 Revenue recognition in midstream and downstream operations

This section discusses revenue recognition under IAS 18 / IAS 11. The new revenue recognition standard IFRS 15 is effective on 1 January 2018. Refer to section 7.2 for further guidance.

Revenue recognition can present some specific challenges in midstream and downstream. Crude oil and gas might need to be moved long distances and might need to be of a specific type to meet refinery requirements. Entities might exchange product to meet logistical, scheduling or other requirements. This section looks at these common issues. Trading of commodities and related issues are considered separately in section 5.7.

3.3.1 Product exchanges

Energy companies exchange crude or refined oil products with other energy companies to achieve operational objectives. A common term used to describe this is a 'buy-sell arrangement'. These arrangements are often entered into to save transportation costs by exchanging a quantity of product A in location X for a quantity of product A in location Y. Variations in the quality or type of the product can sometimes arise. Balancing payments are made to reflect differences in the values of the products exchanged where appropriate. The settlement might result in gross or net invoicing and payment.

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 does not give rise to revenue recognition or gains. An exchange of dissimilar goods results in revenue recognition and gains or losses.

The exchange of crude oil, even where the qualities of the product 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 is adjusted against the carrying value of the inventory. There might, however, be unusual circumstances where the facts of the exchange suggest that there are significant differences between the crude oil exchanged. An example might be where one quality of oil, for example, light sweet crude, is exchanged for another, for example, heavy sour crude, in order to meet the specific mix of crude required for a particular refinery's operations. Such a transaction should be accounted for as a sale of one product and the purchase of the other at fair values.

A significant cash element in the transaction is an indicator that the transaction might be a sale and purchase of dissimilar products.

The new revenue standard IFRS 15, effective on 1 January 2018, excludes non-monetary exchanges from its scope. Refer to section 7.2.2 for further details.

3.3.2 Oil and gas balances

It is common for parties to a gas processing plant to be allocated volumes of gas different from amounts contributed to processing leading to a 'gas imbalance'. The processor must consider whether these transactions, in effect, give rise to purchase and/or sale transactions by the processor, similar to the discussion of overlift and underlift in section 2.6.1.

The effect of the new revenue standard on accounting for these transactions is discussed in section 7.2.3.

3.3.3 Cost, insurance and freight versus free on board

Refer to section 7.2.5 for the potential impact of the new revenue standard on accounting for free on board (FOB) and cost, insurance and freight (CIF) contracts.

Oil and gas are often extracted from remote locations and require transportation over great distances. Transportation by tanker instead of pipeline can be a significant cost. Companies often sell prior to shipping but their oil or gas will be held at the port of departure. The resulting revenue contracts have two main variants with respect to future shipping costs: CIF or FOB.

CIF contracts mean that the selling company will have the responsibility to pay the costs, freight and insurance until the goods reach a final destination, such as a refinery or an end user. However, the risk of the goods is usually transferred to the buyer once the goods have crossed the ship's rail and been loaded onto the vessel.

IAS 18 focuses on whether the entity has transferred to the buyer the significant risks and rewards of ownership of the goods as a key determination of when revenue should be recognised. Industry practice has been that the transfer of significant risks and rewards of ownership occurs when the goods have passed the ship's rail; accordingly, revenue will be recognised at that point, even if the seller is still responsible for insuring the goods whilst they are in transit. However, a full understanding of the terms of trade will be required to ensure that this is the case.

FOB contracts mean that the selling company delivers the goods when the goods pass the ship's rail, but it is not liable for any other costs after this point. FOB contracts often stipulate that the purchaser will assume the risk of loss on delivery of the product to an independent carrier – it is the purchaser's responsibility to pay for any insurance costs, and so the purchaser would be assuming the risk of loss. The point at which the good have passed the ship's rail is usually considered to be the point at which the transfer of significant risks and rewards of ownership is considered to have occurred, because the seller has no further performance obligations.

3.3.4 Agency arrangements

It is important to identify whether an entity is acting as a principal or an agent in transactions, because it is only when the entity is acting as a principal that it will be able to recognise revenue based on the gross amount received or receivable in respect of its performance under a sales contract. Entities acting as agents do not recognise revenue for any amounts received from a customer to be paid to the principal.

Whether an entity is acting as a principal or agent is dependent on the facts and circumstances of the relationship. Indicators that an entity should account for a transaction as a principal include:

- An expectation by the customer that the entity is acting as the primary obligor in the arrangement.
- The entity has latitude, within economic constraints, to set the selling price with the customer. Conversely, where the amount that the entity earns is fixed in advance and is either a fixed fee per transaction or a stated percentage of the amount invoiced, this would normally indicate that the entity is acting as an agent.
- The entity has inventory risk – that is, exposure to the risks of damage, slow movement and obsolescence and changes in suppliers' prices.
- The entity performs part of the services provided or modifies the goods supplied.
- The entity has or assumes the credit risk associated with the transaction.

Producers might deliver product to an agent who will market and sell the product on behalf of the producer. From the agent's perspective, IAS 18 stipulates that revenue is only recognised in relation to the agent's fee or commission on sale.

For example, in a tolling arrangement, if the owner of the pipeline received only the toll charge and the risk of loss remained with the producer until delivery to the final vendor, the pipeline owner would not recognise the gross value of any shipments of refined oil; rather, it would

recognise only its charge element. The pipeline owner would be seen to be acting as an agent of the producer (see section 3.3.4 below).

However, a processing plant or pipeline might use a portion of the commodity flowing through it for fuel to support its operations. The processor or transportation company should consider whether this portion of in-kind fuel represents revenue received as a principal for the service provided. If the fuel was not provided by the customer, the processor or transportation company would have charged an additional toll.

The key remains to establish which party holds the risks and rewards of the transaction. It is not appropriate to recognise the transactions as agent transactions simply because the cash flows are received net.

The indicators under IFRS 15 have some similarities to existing guidance but are provided in a new context of control. Refer to section 7.2.4 for further discussion.

3.3.5 Tolling arrangements

Many companies involved in the industry provide value-added services to companies that produce crude oil or natural gas. These companies might be involved in refining oil, compressing natural gas for transportation to a processing plant, processing gas or transporting product on behalf of an oil and gas producer. The producer might have agreed the sale with the end user or it might be selling to the refining or processing company who will then sell to an end user.

For example, a refinery might operate on either a purchase or a toll basis. On a purchase basis, the refinery is entitled to a charge based on the final sale price of the refined oil produced. On a toll basis, the refinery is entitled to a treatment (toll) charge, which is usually fixed by contract or based on a formula relating to the selling price of the refined oil.

Revenue recognition by the upstream oil company might then be:

- when it ships the crude oil to the refinery;
- when the crude oil arrives at the refinery;
- at the end of the period in which the refinery has to make provisional payment; or
- when the refinery advises the producer of the final refined product quantities and, in some instances, sales price.

The appropriate point of revenue recognition from the upstream oil company's perspective is determined based on the transfer of risks and rewards, taking into account the factors discussed previously. The risk of loss is a key consideration in all intermediary arrangements, because the risk of loss might transfer directly from the producer to the final purchaser, with the intermediary not assuming any risk of physical loss.

The refinery will have to consider whether it is acting as an agent or principal in its transaction with the upstream oil company by taking into account the factors in section 3.3.4. Refer to section 7.2.4 for further discussion of IFRS 15 criteria.

When the product is not considered to be sold to the service provider, an assessment of whether the service arrangement also constitutes a lease under IFRIC 4 *Determining whether an arrangement contains a lease* must also be performed (see section 4.8.2). Accounting for leases under IFRS 16 is discussed in section 7.3.

3.3.6 Oilfield services

Oilfield services companies provide a range of services to other companies within the industry. This can include performing geological and seismic analysis, providing drilling rigs, and managing operations.

The contractual terms and obligations are key to determining how revenue from an oilfield services contract is recognised. An entity should define the contract, identify the performance obligations (and whether there are any project milestones), and understand the pricing terms. If an entity provides drilling rigs, the costs of mobilisation and demobilisation are one area where the terms of the contract must be clearly understood in order to conclude on the accounting treatment for costs incurred.

Revenue recognition for the rendering of services often uses the percentage of completion method. Entities using this approach should be aware of any potential loss-making contracts and collectability issues – revenue can only be recognised to the extent of costs incurred which are recoverable.

Entities providing oilfield services should consider whether their contracts fall within the scope of IAS 17 or IFRIC 4 or IFRS 16 as leases. Refer to section 4.8 for detailed discussion on leasing and to section 7.3 for discussion on leases under IFRS 16.

3.4 Emissions trading schemes

The ratification of the Kyoto Protocol by the EU required reducing total emissions of greenhouse gases within the EU member states. The EU Emissions Trading Scheme (EU ETS), introduced in 2005, represented a significant EU policy response to the challenge. The EU ETS is now in its third phase (phase 3, 2013 – 2020). 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. The number of emission allowances is established for the EU companies each year. Allowances are allocated to the companies through auctions for a defined compliance period. The companies can trade these allowances with each other, as needed. Every year a company must surrender enough allowances to cover all of its 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 the Western Climate Initiative in the United States, and the Chicago Climate Exchange in North America.

The IASB has an ongoing project for emissions trading, but there has been little activity on this project recently. The remainder of this section is based on current IFRS.

3.4.1 Accounting for ETS

The emission rights permit an entity to emit pollutants up to a specified level.

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 guidance in IFRIC 3 remains valid, but several alternative approaches have emerged in practice. A cap and trade scheme can result in the recognition of assets (allowances), expense of emissions, a liability (obligation to submit allowances) and, potentially, income from government grants.

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*. [IAS 20 para 23].

The allowances recognised are not amortised if the residual value is at least equal to carrying value. [IAS 38 para 100]. 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, such as a units of production approach, can be used if it is a better reflection of the consumption of the economic benefits of the government grant.

The entity might choose to apply the revaluation model in IAS 38 *Intangible assets* for the subsequent measurement of the emissions allowances. The revaluation model requires the carrying amount of the allowances to be 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 [IAS 38 paras 75, 85–86]. 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. [IAS 37 para 14]. 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 to the government.

The provision recognised is measured at the amount that it is expected to cost the entity to settle the obligation. This will be the market price at the balance sheet date of the allowances required to cover the emissions made to date (the full market value approach). [IAS 37 para 37]. An alternative is to measure the obligation in two parts, as follows [IAS 37 para 36]:

- i) the obligation for which allowances are already held by the entity – this could be measured at the carrying amount of the allowances held; and
- ii) the obligation for which allowances are not held and must be purchased in the market – this is measured at the current market price of allowances.

Entities using the alternative two-part approach should measure the obligation for which allowances are held by allocating the value of allowances to the obligation on either a FIFO or weighted average basis. Entities using this approach should only recognise an obligation at the current market price of allowances to the extent that emissions made to date exceed the volume of allowances held. There is no obligation to purchase additional allowances if emissions do not exceed allowances.

3.4.2 Certified emissions reductions (CERs)

The United Nations (United Nations Framework Convention on Climate Change) has a mechanism, the Clean Development Mechanism (CDM) which allows developed nations (Annexure I countries) to earn emissions-reduction credits towards Kyoto targets through investment in “green” projects in developing countries.

Firms and governments can invest in the CDM by buying emissions credits – Certified Emissions Reductions (CERs) – generated by pollution-curbing projects such as wind farms and new forests in developing countries. These CERs can be converted into EU Allowances (EUA), which can be used by firms and governments to satisfy their carbon emission obligations. A CER scheme is not a cap and trade scheme.

The United Nations established a CDM Board that selects the entities with environmentally friendly projects (Green Entities). These entities receive CERs from the United Nations, provided that the project is approved by the CDM Board.

The Green Entity will continue to receive CERs for as long as it continues to produce green fuel. CERs can be traded, and market prices are available.

CERs are assets that should be recognised by the entity that holds them. They are assets of an intangible nature, and they should be accounted for either as intangible assets in accordance with IAS 38, or as inventories in accordance with IAS 2. Intangible asset classification is appropriate if the entity plans to use the CERs to satisfy its emissions obligations, for example by exchanging the CERs for EU ETS allowances (or equivalents) and delivering these allowances in satisfaction of its emissions obligations. Inventory classification is appropriate if the entity plans to sell the CERs.

Recognition of CERs produced by an entity should be at cost, or at fair value if the fair value model in IAS 20 is applied. The CERs are awarded in accordance with the UN criteria. The UN is similar to a government entity, and so IAS 20 is applied by analogy. Accordingly, CERs can be recognised at cost or at fair value, with a corresponding deferred income balance recognised as the difference between fair value and cost. The cost of CERs produced should be determined using an appropriate cost allocation model, which values the CERs produced and the green fuel produced as joint products.

3.5 Depreciation of downstream assets

This section focuses on the depreciation of downstream assets such as refineries, gas treatment installations, chemical plants, distribution networks and other infrastructure.

Downstream phase assets are depreciated using a method that reflects the pattern in which the asset's future economic benefits are expected to be consumed. The depreciation is allocated on a systematic basis over an asset's useful life. The residual value and the useful lives of the assets are reviewed at least at each financial year-end and, if expectations differ from previous estimates, the changes are accounted for as a change in an accounting estimate in accordance with IAS 8 *Accounting policies, changes in accounting estimates and errors*.

Downstream assets such as refineries are often depreciated on a straight line basis over the expected useful lives of the assets. An alternative approach is using a throughput basis. For example, for pipelines used for transportation, depreciation can be calculated based on units transported during the period as a proportion of expected throughput over the life of the pipeline.

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. [IAS 16 paras 43–44]. The requirements of IFRS in respect of components are considered in section 2.8.3.

The significant components of these types of assets must be separately identified. This can be a complex process, particularly on transition to IFRS, because the detailed recordkeeping might 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.

3.5.1 Cost of turnaround/overhaul

The costs of performing a major turnaround/overhaul are capitalised if the turnaround gives access to future economic benefits. Such costs will include the labour and materials costs of performing the turnaround. However, turnaround/overhaul costs that do not relate to the replacement of components or the installation of new assets should be expensed as incurred. [IAS 16 para 12]. 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.

Refinery turnarounds

How should refinery turnarounds be accounted for?

Background

Entity Y operates a major refinery. Management estimates that a turnaround is required every 30 months. The costs of a turnaround are approximately \$500,000: \$300,000 for parts and equipment, and \$200,000 for labour to be supplied by employees of entity Y.

Management proposed to accrue the cost of the turnaround over the 30 months of operations between turnarounds and to create a provision for the expenditure.

Is management's proposal acceptable?

Solution

No. It is not acceptable to accrue the costs of a refinery turnaround. Management has no constructive obligation to undertake the turnaround. The cost of the turnaround should be identified as a separate component of the refinery at initial recognition and depreciated over a period of 30 months. This will result in the same amount of expense being recognised in the income statement over the same period as the proposal to create a provision.

4. Sector-wide accounting issues

4.1 Business combinations

4.1.1 Overview

Acquisition of assets and businesses are common in oil and gas (O&G). Over the past few years, market conditions have been challenging. Acquisitive entities that seek to secure access to reserves or replace depleting reserves face a variety of accounting issues due to significant changes in the accounting for merger and acquisition transactions. This adds more complexity to the already challenging economic conditions. The broad requirements of IFRS 3 *Business combinations* include:

- recognition at fair value of all forms of consideration at the date of the business combination;
- remeasurement to fair value of previously held interests in the acquiree with resulting gains through the income statement as part of the accounting for the business combination;
- providing more guidance on separation of other transactions from the business combination, including share-based payments and settlement of pre-existing relationships;
- expensing transaction costs; and
- two options for the measurement of any non-controlling interest (NCI, previously minority interest) on a combination-by-combination basis: fair value, or proportion of net asset value.

4.1.2 Definition of a business

The IASB issued an Exposure Draft on Definition of a Business in June 2016. It is expected that the amendments will add clarity to whether a transaction should be classified as a business combination or as a purchase of assets. The proposed amendments will likely result in more acquisitions being classified as acquisitions of assets.

A business is a group of assets that includes inputs, outputs and processes that are capable of being managed together for providing a return to investors or other economic benefits. Not all of the elements need to be present for the group of assets to be considered a business. Significant judgement is required in the determination of what is a business.

Upstream activities in the production phase will typically represent a business, whereas those at the exploration stage will typically represent a collection of assets. A licence to explore, on its own, is normally just an asset. If a number of assets are owned and there are additional processes which exist to manage that portfolio, it might represent a business. Projects that lie in the development stage are more difficult to judge and will require consideration of the stage of development and other relevant factors. A development project with significant infrastructure costs remaining and no potential customers is more likely to be an asset. As these matters are resolved and the projects gets closer to the production stage, the evaluation as to whether an asset or business exists becomes more complicated. Each acquisition needs to be evaluated based on the specific facts and circumstances.

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.

If the assets purchased do not constitute a business, the acquisition is accounted for as the purchase of individual assets. The distinction is important because, in an asset purchase:

- no goodwill is recognised;
- deferred tax is generally not recognised for asset purchases (because of the initial recognition exemption (IRE) in IAS 12 *Income taxes*, which does not apply to business combinations);

- transaction costs are generally capitalised; and
- asset purchases settled by the issue of shares are within the scope of IFRS 2 *Share-based payments*.

Distinguishing between business combinations and purchase of assets – practical examples

IFRS 3 defines a business as “consisting of inputs and processes applied to those inputs that have the ability to create output”. All three elements – input, process and output – should be considered in determining whether a business exists. We demonstrate the practical application of these principles below:

| Acquisition | Inputs | Processes | Outputs | Conclusion |
|---|---|---|---|---|
| Incorporated entity which has one asset in the early exploration phase but the group does not have a production licence yet. No proven reserves. | No inputs, because the entity is at the exploration stage. Employees insignificant in number. | Exploration programme but no processes in place to convert inputs. No production plans. | There is no development plan yet and no planned production. The only potential output might be results of early exploration work. | Likely to be an asset, because there is a lack of the business elements (e.g. inputs, processes and outputs). |
| Listed company with a portfolio of properties. Active exploration program in place and there are prospective resources. Company normally develops properties to production. | Portfolio of properties and employees. | Exploration programme, O&G engineers and expertise, development programme, management and administrative processes. | Production has not begun: however, since there is an active portfolio, it might be that exploration results could be viewed as output. Consideration required as to whether market participant could produce outputs with the established inputs and processes. | Judgement required. |
| Listed company with a portfolio of properties. All exploration activities have been suspended and no properties have moved forward into development. | No inputs. | No processes, because there is not active exploration program in place. | There is no plan for further exploration and no development plans. | Judgement required. |

| Acquisition | Inputs | Processes | Outputs | Conclusion |
|--|---|---|---|--|
| Listed company with a portfolio of properties. Active exploration program and prospective resources. Company's policy is to hold portfolio of properties and sell in and out of them after undertaking exploration. The company does not hold the properties to development. | Portfolio of properties with successful exploration activities and employees. | Exploration program | Exploration asset with associated resource information. | Judgement required. |
| Listed company. Property in development phase. Some reserves and resources. | O&G reserves and employees. | Operational processes associated with mineral production. | Revenues from O&G production. | Judgement required, but likely to be a business – all three elements exist. |
| Producing asset owned by a listed company. Only the asset is purchased. | O&G reserves and employees. | Operational processes associated with mineral production. | Revenues from O&G production. | Judgement required, but likely to be a business – all three elements exist. Although the 'asset' does not constitute an incorporated entity, it is a business. |
| Alliance with another company to develop a property. | None. | None. | None. | Jointly controlled asset. Assets acquired do not meet the definition of a business. |

4.1.3 Identifying a business combination

Transactions can be structured in a variety of ways, including purchase of shares, purchase of net assets, and establishment of a new company that takes over existing businesses and restructuring of existing entities. If there are a number of transactions linked together, or transactions that are contingent on completion of each other, the overall result is considered as a whole. IFRS focuses on the substance of transactions and not the legal form to determine if a business combination has taken place.

The only exemptions to applying business combination accounting under IFRS are:

- when the assets acquired do not constitute a business (as discussed above);
- the formation of a joint arrangement in the financial statements of the joint arrangement itself (see section 4.2); and
- businesses that are under common control (where no change in ownership takes place).

A business combination occurs when control is obtained. Both existing voting rights and capacity to control in the form of currently exercisable options and rights are considered in determining when control or capacity to control exists.

4.1.4 Acquisition method

The acquisition method of accounting is applied to all business combinations. The acquisition method comprises the following steps:

- identifying the acquirer and determining the acquisition date;
- recognising and measuring the consideration transferred for the acquiree;
- recognising and measuring the identifiable assets acquired and liabilities assumed, including any NCI; and
- recognising and measuring goodwill or a gain from a bargain purchase.

Identifying the acquirer and determining the acquisition date

Identifying the acquirer is the first step of any business combination. The acquirer in the combination is the entity that obtains control of one or more businesses. The distinction is significant, because it is only the acquiree's identifiable net assets that are fair valued. The acquirer's net assets remain at existing carrying values.

Consideration transferred

Transaction costs are expensed and not included as part of the consideration transferred.

The acquirer must identify any transactions that are not part of what the acquirer and the acquiree exchange in the business combination, and it must separate them from the consideration transferred for the business. Examples include: the amount paid or received for the settlement of pre-existing relationships; and remuneration paid to employees or former owners for future services.

Contingent consideration

The purchase consideration might vary, depending on future events. The acquirer might want to make further payments only if the business is successful. The vendor, on the other hand, wants to receive the full value of the business. Contingent consideration in the O&G industry often takes the form of:

- royalties payable to the vendor as a percentage of future oil revenue;
- payments based on the achievement of specific levels of production or specific prices of oil; and
- payments on achievement of milestones in the different phases (that is exploration, development and production).

An arrangement containing a royalty payable to the vendor is different from a royalty payable to the tax authorities of a country. A royalty payable to the vendor in a business combination is often contingent consideration; essentially a type of earn-out. However, amounts described as royalties might often instead be the retention of a working interest. If so, different accounting will be applied. Judgement is required as to whether a royalty or a retained working interest exists.

The acquirer should fair value all of the consideration at the date of acquisition including the contingent consideration (earn-out). Since fair value takes account of the probabilities of different outcomes, there is no requirement for payments to be probable. Therefore, contingent consideration is recognised whether it is probable that a payment will be made or not.

This may well be a change for many O&G companies that have treated vendor-type royalties as period costs. Any subsequent payment or transfer of shares to the vendor should be scrutinised to determine if it is contingent consideration.

Contingent consideration can take the form of a liability or equity. If the earn-out is a liability (cash or shares to the value of a specific amount), any subsequent re-measurement of the liability is recognised in profit and loss. If the earn-out is classified as equity it is not remeasured, and any subsequent settlement is accounted for within equity.

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

IFRS 3 requires all identifiable assets and liabilities (including contingent liabilities) acquired or assumed to be recorded at their fair value. These include assets and liabilities that might not have been previously recorded by the entity acquired (e.g. 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 and supplier contracts, use rights (such as drilling, water, and hydrocarbon), and patented/unpatented technology.

Some of the common identifiable assets and liabilities specific to the O&G industry that might be recognised in a business combination, in addition to inventory or property, plant and equipment, include the following:

- exploration, development and production licences;
- O&G properties;
- purchase and sales contracts; and
- environmental/closure provisions.

Undeveloped properties/resources

Undeveloped properties and resources or exploration potential can present challenges when ascribing fair value to individual assets, particularly those properties still in the exploration phase for

which proven or probable reserves have not yet been determined. A significant portion of the consideration transferred might relate to the value of these undeveloped properties.

Management should consider similar recent transactions in the market and use market participant assumptions to develop fair values. The specific characteristics of the properties also need to be taken into account, including the type and volume of exploration and evaluation work on resource estimates previously carried out, the location of the deposits and expected future commodity prices. The challenges associated within this are discussed further in section 4.1.7.

Tax amortisation benefit

In many business combinations, especially related to O&G acquisitions, the fair value of assets acquired uses an after-tax discounted cash flow approach. Inherent in this approach is an amount for the present value of the income tax benefits of deducting the purchase price through higher future depreciation and depletion charges. This is often referred to as the tax amortisation benefit (TAB).

An asset's fair value in a business combination should reflect the price which would be paid for the individual asset if it were to be acquired separately. Accordingly, any TAB that would be available if the asset were acquired separately should be reflected in the fair value of the asset.

The TAB will increase the value of intangible and tangible assets and reduce goodwill. Assets that are valued via a market observable price rather than the use of discounted cash flows (DCF) should already reflect the general tax benefit associated with the asset. Where the fair value has been determined using a DCF model, the TAB should normally be incorporated into the model.

Key questions

There are key questions for management to consider in a business combination that can affect the values assigned to assets and liabilities, with a resulting effect on goodwill. These questions include:

- *Have all intangible assets, such as Geological and Geophysical information, O&G property, and exploration potential, been separately identified?* There could be tax advantages in allocating value to certain assets, and each will need to be assessed in terms of their useful lives and impact on post-acquisition earnings.
- *Have environmental and rehabilitation liabilities been fully captured?* The value that the acquirer would need to pay to a third party to assume the obligation could be significantly different from the value calculated by the target.
- *Does the acquiree have contracts at a price that is favourable or unfavourable to the market?* Such contracts would have to be fair valued as at the date of acquisition.
- *Do the terms of purchase provide for an ongoing royalty, other payments or transfer of equity instruments?* These arrangements could be contingent consideration that needs to be fair valued as at the date of acquisition.
- *Does the acquiree use derivative instruments to hedge exposures?* Post-combination hedge accounting for pre-combination hedging instruments can be complex. The acquirer will need to designate these and prepare new contemporaneous documentation for each hedging relationship.
- *Have all embedded derivatives been identified?* New ownership of the acquired entity might mean that there are changes in the original conclusions reached when contracts were first entered into.

The above questions provide a flavour of the issues that management should consider in accounting for business combinations, and they highlight the complexity of this area.

4.1.5 Goodwill in O&G acquisitions

Goodwill remains a residual in business combination accounting – that is, the difference between consideration transferred and the fair value of identifiable assets acquired and liabilities assumed. IFRS 3 has broadened the definition of a business and thus more O&G transactions might be business combinations. Past practice under some national GAAPs and earlier versions of IFRS was that little or no goodwill was recognised in business combinations in O&G. Any residual value after the initial fair value exercise might have been re-allocated to O&G properties (that is proved, probable and possible reserves). This approach has largely disappeared with the issuance of IFRS 3.

Management of the acquirer should carry out a thorough analysis and fair value exercise for all the identifiable tangible and intangible assets of the acquired business. Once this has been completed, any residual forms goodwill. Goodwill might also arise mechanically from the requirement to record deferred tax in a business combination, and this is further discussed below.

Goodwill can arise from several different sources. For example, goodwill might arise if a specific buyer can realise synergies from shared infrastructure assets (for example, oil pipelines) or oil extraction techniques that are not available to other entities. Goodwill might also represent access to new markets, community/ government relationships, portfolio management, technology, expertise, the existence of an assembled workforce and deferred tax liabilities. An O&G entity might be willing to pay a premium to protect the value of other O&G operations that it already owns, and this would also represent goodwill.

Goodwill could also arise from the requirements to recognise deferred tax on the difference between the fair value and the tax value of the assets acquired in a business combination. The fair value uplift to O&G properties and exploration assets is often not tax deductible and therefore results in a deferred tax liability.

The fair value attributed to some intangible assets could increase if their associated amortisation is deemed to be deductible for tax purposes. The TAB is discussed in section 4.1.4 above. The impact would be an increase in the value of the asset and a decrease in the value of goodwill.

Goodwill and non-controlling interests

IFRS 3 gives entities a choice on the measurement of NCI that arises in a less than 100% business combination. The choice is available on a transaction-by-transaction basis. An acquirer can recognise the NCI either at fair value, which leads to 100% of goodwill being recognised (full goodwill), or at the NCI's proportionate share of the acquiree's identifiable net assets (partial goodwill). This leads to goodwill being recognised only for the parent's interest in the entity acquired.

Bargain purchase

There might be situations where sum of the consideration paid by the acquirer, non-controlling interest and the previously held interest is less than the value of the identifiable net. This is called a 'bargain purchase'. This could happen when there is a forced sale, where difficult market conditions exist, or because some items in a business combination are not measured at fair value. If a bargain purchase is identified, the gain should be immediately recognised in the income statement.

The acquirer should ensure that it does have a gain on a bargain purchase, and that it has used all of the available evidence at the date of acquisition and reassessed the business combination accounting.

The acquirer re-assesses the identification and measurement of the acquiree's identifiable assets and liabilities.

A bargain purchase should only exist relating to a distressed transaction where the purchaser could immediately resell the business in an orderly exit transaction at a higher value than the consideration paid.

The acquirer should review the measurement of:

- identifiable assets and liabilities;
- non-controlling interest, if any;
- the acquirer's previously held equity interest, if any;
- consideration transferred.

The assumptions used in fair value measurement for the business combination should be consistent with the assumptions used in subsequent impairment tests.

4.1.6 Deferred tax

An entity recognises deferred tax on the fair value adjustments to the net assets of an acquired O&G company, including any increase in the value of O&G properties and/or exploration assets. No deferred tax liability is recognised on goodwill itself unless the goodwill is tax deductible. Tax deductible goodwill is rare and presents specific accounting issues. The tax base should reflect the manner in which the value of the asset will be realised. Few tax jurisdictions allow companies to claim tax deductions on acquired O&G properties if the asset will be realised through production of oil and gas. In such cases, it is likely that a large deferred tax liability will need to be recognised.

This deferred tax liability can result in the recognition of goodwill, because it reduces the net assets of the acquired entity. The extent of such goodwill will depend on the fair value of the O&G properties and the exploration assets, and it could be significant.

Tax losses

An acquired O&G entity might have tax losses. This can arise even if the entity is trading profitably, as a result of the carry-forward of exploration costs and allowances for capital projects. Such tax losses are recognised as an asset at the date of the business combination if it is probable that they will be utilised by the combined entity.

4.1.7 Provisional assessments of fair values

Acquirers have up to 12 months from the date of an acquisition to finalise the purchase price allocation. This is known as the 'measurement period'. Acquirers will frequently use this time to evaluate the acquired O&G properties and exploration assets. Any adjustments recognised during this period are recorded as part of the accounting for the initial business combination. Further adjustments beyond the 12-month window are recognised in profit and loss as a change in estimate. Where the 12-month window crosses a period end, there might be adjustments to fair values required in the following period. The comparative information for prior periods presented in the current financial statements should be revised as needed, including recognising any change in depreciation, amortisation or other income effects recognised based on the original accounting.

Adjustments to deferred tax assets will only affect goodwill if they are made within the 12-month period for finalising the business combination accounting, and if they result from new information about facts and circumstances that existed at the acquisition date. After the 12-month period,

adjustments are recorded as normal under IAS 12, through the income statement or the statement of changes in equity, as appropriate.

The process of determining a reliable value for assets still in the early phase of exploration can be challenging. The level of uncertainty in ascribing a value to such assets increases the likelihood of subsequent changes having an effect on reported profit.

4.1.8 Business combinations achieved in stages

A business combination achieved in stages is accounted for using the acquisition method at the acquisition date. Previously held interests are remeasured to fair value at the acquisition date, and a gain or loss is recognised in the income statement. The gain or loss would require disclosure in the financial statements. The fair value of the previously held interest then forms one of the components that are used to calculate goodwill, along with the consideration and non-controlling interest less the fair value of identifiable net assets.

4.1.9 Acquisitions of participating interests in jointly controlled assets

Jointly controlled assets that are not incorporated entities are a common method of undertaking development and production within the industry. Acquisition of interests in these assets where there are proven resources (and therefore in the development or production phase), is common. The acquirer needs to assess whether the activity of the joint operation constitutes a business. All principles of business combination accounting should be applied to the acquisition of an interest in the joint operation that constitutes a business.

The acquisition of an interest in jointly controlled assets that do not meet the definition of a business would not result in a business combination. As explained in section 4.1.2, an important consequence is that the acquisition would be treated as the purchase of an asset, with no goodwill or deferred tax arising.

Accounting for purchase of an interest in a non-producing field

Should the acquisition of an interest in a non-producing field be accounted for as a business combination?

Background

There are three participants in a jointly controlled asset, Omega, that is in the early exploration phase. A production licence has not yet been obtained. There are no proven reserves and no development plan in place. The ownership interest of the participants is as follows:

| | |
|----------|-----|
| Entity A | 40% |
| Entity B | 40% |
| Entity C | 20% |

The terms of the joint operating agreement (JOA) require unanimous approval of decisions relating to the exploration.

Entity A purchases entity C's interest of 20% and now holds 60% of the participating interest. Should entity A account for this as a business combination?

Solution

The field is in the early exploration phase. A production licence has not yet been obtained. There are no proven reserves and no development plan in place. The field is not a business. Acquisition of an interest in a joint operation that is not a business would represent an asset acquisition. The consideration for the interest will be capitalised, and no deferred tax or goodwill will arise.

Accounting for purchase of an interest in a producing field

Should the acquisition of an interest in a producing field be accounted for as a business combination?

Background

There are three participants in a jointly controlled asset, Infinity, that is a business. The ownership interest of the participants is as follows:

| | |
|----------|-----|
| Entity A | 40% |
| Entity B | 40% |
| Entity C | 20% |

The terms of the joint operating agreement (JOA) require unanimous approval of decisions relating to the development. The carrying value of the asset in entity A's financial statements is C15 million.

Entity A purchases entity B's interest of 40%. It has paid consideration equivalent to its fair value of C20 million. Entity A now holds 80% of the participating interest. Should entity A account for this as a business combination?

Solution

Yes. The producing field would represent a business. Acquisition of an interest in a joint operation that is a business represents a business combination.

A fair value assessment would be performed of the 'business', and the company would consolidate its 60% share of this. The total fair value of the asset has been assessed as C50 million. Entity A will recognise an asset of C35 million, which consists of the C20 million paid for entity B's share and C15 million for the carrying value of the 40% previously recognised. The previously held interest is not remeasured, because the company retained joint control.

Deferred tax will also need to be considered.

4.1.10 Restructuring costs

Major restructuring programmes often follow business combinations. These costs can only be recognised as part of the business combination if they were previously recognised by the acquiree. Any other costs (such as terminations subsequent to the business combination) must be recorded as an expense in the post-combination income statement of the acquired business. Similarly, any restructuring or other costs incurred by the acquirer itself cannot be included in the business combination.

4.2 Joint arrangements

4.2.1 Overview

Joint ventures and other similar arrangements (joint arrangements) are frequently used by oil and gas companies as a way to share the higher risks and costs associated with the industry or as a way of bringing in specialist skills to a particular project. The legal basis for a joint arrangement may take various forms; establishing a joint venture might be achieved through a formal joint venture contract, or the governance arrangements set out in a company's formation documents might provide the framework for a joint arrangement. The feature that distinguishes a joint arrangement from other forms of cooperation between parties is the presence of joint control. An arrangement without joint control is not a joint arrangement.

4.2.2 Joint control

Joint control is the contractually-agreed sharing of control over an economic activity. An identified group of venturers must unanimously agree on all key financial and operating decisions. Each of the parties that share joint control has a veto right: they can block key decisions if they do not agree.

Not all parties to the joint venture need to share joint control. Some participants may share joint control and other investors may participate in the activity but not in the joint control. Section 4.2.7 discusses the accounting for these participants.

Similarly, joint control may not be present even if an arrangement is described as a 'joint venture'. Decisions over financial and operating decisions that are made by 'simple majority' rather than by unanimous consent could mean that joint control is not present.

This is a complex area which will require careful analysis of the facts and circumstances. If joint control does not exist, the arrangement would not be a joint venture. Investments with less than joint control are considered further in section 4.2.7.

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 dissolution of the joint venture.

One of the venturers acting as operator of the joint venture does not prevent joint control. The operator's powers are usually limited to day-to-day operational decisions; key strategic financial and operating decisions remain with the joint venture partners collectively.

4.2.3 Classification of joint ventures

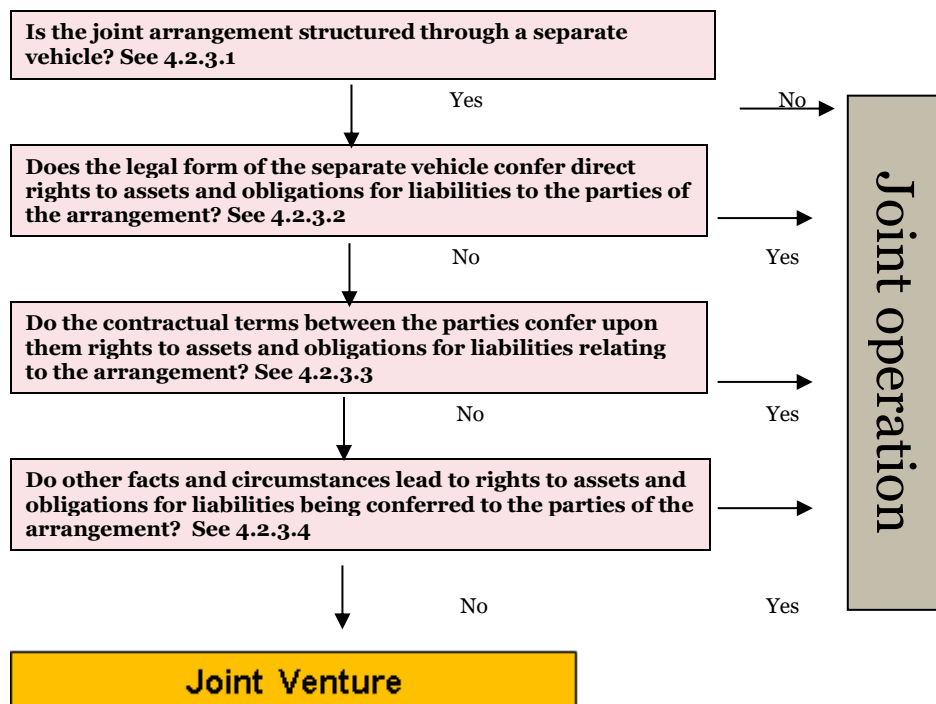
'Joint arrangement' is the term for all cooperative working arrangements where two or more parties have joint control.

| Term | IFRS 11 definition |
|-----------------|---|
| Joint operation | Parties have rights to the assets and obligations for the liabilities relating to the arrangement |
| Joint venture | Parties have rights to the net assets of the arrangement |

A jointly controlled entity may be either a joint operation or a joint venture. The classification of the joint arrangement is based on the rights and obligations of the parties to the arrangements.

Determination of the type of joint arrangement can be a complex decision under IFRS 11. Legal form remains relevant for determining the type of joint arrangement but is less important than under the previous standard. A joint arrangement that is not structured through a separate vehicle is a joint operation. However, not all joint arrangements in separate vehicles are joint ventures. A joint arrangement in a separate vehicle can still be a joint operation; classification depends on the rights and obligations of the venturers and is further influenced by the economic purpose of the joint arrangement.

Determining the classification of joint arrangements is a four step process as shown below:



Separate vehicles

The first step in determining the classification is to assess whether the arrangement is structured through a separate vehicle. A separate vehicle is a separately identifiable financial structure, including separate legal entities or entities recognised by statute, regardless of whether those entities have a legal personality.

The definition of a 'separate vehicle' is quite broad. It does not necessarily need to have a legal personality. Separate vehicles are generally separately identifiable financial structures having

separately identifiable assets, liabilities, revenues, expenses, financial arrangements, financial records etc.

Local laws and regulations also need consideration before determining whether a particular structure meets the definition of a 'separate vehicle'.

Joint arrangements not structured through a separate vehicle

An arrangement that is not structured through a separate vehicle is a joint operation. The parties determine in such contractual arrangements their rights to the assets, and their obligations for the liabilities, relating to the arrangement. These are classified as joint operations. Oil and gas joint working arrangements often do not operate through separate vehicles and so are classified as joint operations.

Joint arrangements structured through a separate vehicle

A joint arrangement that is structured through a separate vehicle can be either a joint venture or a joint operation depending on the parties' rights and obligations relating to the arrangement.

The parties need to assess whether the legal form of the separate vehicle, the terms of the contractual arrangement and, when relevant, any other facts and circumstances give them:

- a) rights to the assets and obligations for the liabilities relating to the arrangement (i.e. joint operation); or
- b) rights to net assets of the arrangement (i.e. joint venture).

Rights to assets and obligations for liabilities conferred by legal form

The second step in determining the classification of a joint arrangement is to assess the rights and obligations arising from the legal form of the separate vehicle.

If the legal structure of the arrangement is such that the parties have rights to assets and are obligated for the liabilities of the arrangement, then it is a joint operation. The local laws and regulations need to be carefully assessed in order to ascertain this.

The key question is whether the separate vehicle be considered in its own right i.e. are the assets and liabilities held in the separate vehicle those of the separate vehicle or are they the assets and liabilities of the parties?

Types of separate vehicle

Partnerships – in most cases general partnerships cannot be considered in their own right i.e. the partners have obligations for the liabilities and have rights to the assets of the partnership in the normal course of business. On the other hand, a limited liability partnership (LLP) may be considered in its own right since the partners are not obligated for the liabilities of the LLP and the assets of the LLP are its own assets.

Limited liability companies – in most jurisdictions these can be considered in their own right i.e. the assets and liabilities of the company are its own assets and liabilities. The creditors and lenders of the company do not have a right to claim payments from the shareholders. However, unlimited

liability companies may sometimes provide direct rights to assets and obligations for liabilities to the parties depending on the relevant facts and circumstances.

Unincorporated entities – when an arrangement is operated through this type of vehicle, in most cases the parties will have the right to assets and have obligations for the liabilities of the arrangement.

Local laws and regulations play a key role in the assessment of the rights and obligations conferred by the separate vehicle. The same legal form (such as a partnership) in different territories could give different rights and obligations depending on the local laws and regulations.

The contractual terms between the parties and, when relevant, other facts and circumstances can override the assessment of the rights and obligations conferred by the legal form.

Rights to assets and obligations for liabilities established by contract

The rights and obligations agreed to by the parties in their contractual terms are usually consistent with the rights and obligations conferred on the parties by the legal form of the separate vehicle.

The parties may enter into contractual terms which modify or reverse the rights and obligations conferred by the legal form of the arrangement. The contractual terms have to be carefully assessed to ensure the appropriate classification of a joint arrangement.

Indicators of a joint operation in contractual arrangements

Rights to assets

The parties share all interests (e.g. rights, title or ownership) in the assets in a specified proportion (e.g. in proportion to the parties' ownership interest in the arrangement or in proportion to the activity carried out through the arrangement that is directly attributed to them).

Obligations for liabilities

The parties share all liabilities, obligations, costs and expenses in a specified proportion as in the case of rights to assets.

Revenues and expenses

The contractual arrangement usually establishes the allocation of revenues and expenses on the basis of the relative performance of each party to the joint arrangement. For example, the contractual arrangement might establish that revenues and expenses are allocated on the basis of the capacity that each party uses in a refinery or smelter operated jointly, which could differ from their ownership interest in the joint arrangement.

In other instances, the parties may agree to share the profit or loss relating to the arrangement on the basis of a specified proportion such as the parties' ownership interest in the arrangement. This would not prevent the arrangement from being a joint operation if the parties have rights to the assets, and obligations for the liabilities, relating to the arrangement.

Indicators of a joint venture in contractual arrangements

Rights to assets

Generally the contractual terms establish that the assets acquired by the arrangement are those of the arrangement and the parties do not have any direct interests in the title or ownership of the assets.

Obligations for liabilities

The contractual terms establish that the arrangement is liable for the debts and obligation of the arrangement and that the parties are only liable to the extent of unpaid capital and guarantees. The creditors of the joint arrangement do not have a right of recourse against the joint venture parties.

Revenues and expenses

The contractual arrangement establishes each party's share in the net profit or loss relating to the activities of the arrangement.

The assessment of rights and obligations should be carried out as they exist in the “normal course of business” (para B14 of IFRS 11) i.e. the rights and obligations as they exist during the day-to-day operation of the company. Legal rights and obligations arising in circumstances which are other than in the “normal course of business” such as liquidation and bankruptcy are much less relevant.

‘Other facts and circumstances’ should be assessed before finally concluding on the classification of the arrangement as these can sometimes affect the rights and obligations conferred by the legal form and the contractual terms. ‘Other facts and circumstances’ are discussed in more detail below.

Impact of guarantees on classification of a joint arrangement

Parties to joint arrangements often provide guarantees to third parties on behalf of the arrangement when the arrangement is purchasing goods, receiving services or obtaining financing. Issuing a guarantee does not on its own mean that the arrangement is a joint operation.

All relevant facts and circumstances should be considered in determining the classification. Rights and obligations of the parties to a joint arrangement are assessed as they exist in the normal course of business. It is not appropriate to make a presumption that the arrangement will not settle its obligations and that the parties will be obligated to settle those liabilities because of the guarantee issued. This would not be seen as a normal course of business.

‘Other facts and circumstances’

This is the final step in determining the classification of a joint arrangement. Assessing ‘other facts and circumstances’ essentially means assessing the purpose and design of setting up the arrangement i.e. what was the objective or intent of the parties in setting up the arrangement?

Assessment of ‘other facts and circumstances’ grows more challenging as the arrangements between parties become increasingly complex. When arrangements are incorporated in limited liability

companies, classifying them as joint operations on the basis of ‘other facts and circumstances’ is not easy and is a high hurdle to cross. This is because classifying them as joint operations means that the corporate veil has to be pierced. The parties’ will then record assets and liabilities relating to the arrangement, although legally they neither have rights to the assets nor the obligation for the liabilities. Consideration should be given to all facts and circumstances before reaching a conclusion.

The IFRS IC has determined that the assessment of other facts and circumstances should be undertaken with a view towards whether those facts and circumstances create enforceable rights to assets and obligations for liabilities.

Listed below are some of the general characteristics of an arrangement with the purpose and design of a joint operation:

- Parties generally restrict the arrangement from selling the output to third parties to ensure that they have uninterrupted access to the output.
- There is a binding obligation on the parties to purchase substantially all of the output – if the parties did not have an obligation to take the output, the arrangement may sell the output to third parties, indicating that the purpose and design of the arrangement was not to provide all of its output to the parties. Monetary value of the output is more relevant than physical quantities. Nature of the output does not impact the assessment.
- The demand, inventory and credit risks relating to the activities of the arrangement are passed on to the parties and do not rest with the arrangement.
- The parties ensure that the output is purchased from the arrangement at a price that covers all the costs of the arrangement and it operates at a break-even level. Market price might not provide cash flows at sufficient level. Selling output at a market price does not prevent classifying the arrangement as a joint operation. The key is to assess the purpose and design of the arrangement. It may not be necessary for the arrangement to operate at a break-even level. If the arrangement is designed to provide all the output to the parties, the price at which the output is purchased by the parties may become a less relevant factor in determining the classification.
- The arrangement does not generally have any borrowings and the parties are substantially the only source of cash flows. Arrangements may have borrowings for financing their working capital requirements or for capital expansion. As long as the arrangement is designed to provide all the output to the parties, it means that the arrangement will not be able to make the interest payments and the principal repayments without receiving funds from the parties. This may indicate that the arrangement continues to be a joint operation.

‘Other facts and circumstances’ scenarios

Each of the scenarios below has the following facts and assumptions:

- joint control exists; and
- the legal structure of the separate vehicle and the contractual terms do not give the parties rights to assets and obligations for liabilities.

The initial indicators may suggest a joint venture, however other facts and circumstances are analysed to see how they may affect the classification of the arrangement.

| Scenarios | Classification | Analysis |
|--|------------------------|--|
| <p>The arrangement produces a product and the parties are obligated to take all of the output in the ratio of their shareholding.</p> <p>The price of output is set by the parties at a level such that the arrangement operates at break-even level.</p> <p>The arrangement is prohibited from selling the output to third parties.</p> | <p>Joint operation</p> | <p>The design of the arrangement is to provide all its output to the parties. It is dependent on the parties for its cash flows to ensure continuity of operations. The parties get substantially all the economic benefits from the assets of the arrangement. It is a joint operation.</p> |
| <p>Same facts as above except that the product is a commodity like oil which is readily saleable in the market i.e. if the parties do not buy it can be easily sold to a third party.</p> | <p>Joint operation</p> | <p>Similar to above, it is a joint operation. The fact that the product is readily saleable becomes less relevant because there is an obligation on the arrangement to sell all of its output to the parties.</p> |

| Scenarios | Classification | Analysis |
|---|---------------------------------------|---|
| <p>The arrangement produces two products – oil and gas.</p> <p>100% of oil is taken by one party and 100% of gas is taken by the other party at market value.</p> <p>Since these are purchased by the parties at market value there is a residual profit or loss left in the arrangement which is distributed by way of dividends to the parties in the proportion of their shareholding.</p> | <p>Likely to be a joint operation</p> | <p>The parties don't have to set up a joint arrangement for an interest in the same product. They may have interest in different products but may set up a joint arrangement for reasons like costs saving, similar manufacturing processes, etc.</p> <p>It appears that this arrangement is dependent on the parties for cash flows and the parties take all output. This is a strong indicator that the arrangement may be a joint operation.</p> <p>Before determining the classification, consideration should be given to all facts and circumstances. Certain other factors may impact classification, including:</p> <ul style="list-style-type: none"> • whether the parties have a contractual obligation to take all of the output – if so, then it is a joint operation; • the relative values of the products purchased compared to the proportion of investments made by the parties; • the value of one of the products may be relatively lower and the investor who purchases that product may get compensated in some other way such as share of profits made from sales to the other party. |

| Scenarios | Classification | Analysis |
|--|--------------------------------------|--|
| <p>Parties have the right of first refusal to buy the output but they are not obligated to take the output.</p> <p>The arrangement was set up three years ago. In the first year the parties take all of the output in the ratio of their shareholding.</p> <p>In the second year, the product is sold to third parties.</p> <p>In the third year, the parties take all of the output but in a ratio different from their shareholding.</p> | <p>Likely to be a joint venture.</p> | <p>The following factors indicate that the arrangement is most likely a joint venture:</p> <ul style="list-style-type: none"> • there is no obligation on the arrangement to sell its output to the parties. This indicates that the purpose and design of the arrangement was not to provide all of the output to the parties; • in the past output has been sold to third parties. This proves that the arrangement is not substantially dependent on the parties for its cash flows. <p>All facts and circumstances should be considered before determining the classification. The design of the arrangement may be to provide all of the output to the parties. However in a particular year, due to certain practical considerations, the arrangement sells output to third parties or the parties take varying level of outputs. From the next year they may revert to taking their share of outputs. In such cases, emphasis should be given to the purpose and design of the arrangement.</p> |
| <p>Two parties set up an arrangement to drill for oil. The oil produced is sold to third parties.</p> <p>As per the contractual terms:</p> <ul style="list-style-type: none"> • all the gross cash proceeds from revenue of the arrangement are transferred to the parties on a monthly basis in proportion of their shareholding; • the parties agree to reimburse the arrangement for all its costs in proportion of their shareholding based on cash calls. | <p>Likely to be a joint venture</p> | <p>In this case, it is clear that the purpose and design of the arrangement is not to provide all of its output to the parties.</p> <p>The arrangement is selling the product to third parties and generating its own cash flows.</p> <p>Transferring gross proceeds of revenues to the parties and making cash calls for incurring its costs does not indicate that the parties have rights to assets and obligations for liabilities of the arrangement. It is merely a funding mechanism. It is no different from the parties having an interest in the net results of the arrangement.</p> |

| Scenarios | Classification | Analysis |
|---|--------------------|---|
| Two parties set up a joint arrangement. One of the parties takes 100% of the gas produced at market prices and the other party only takes its share of the profits/loss made by the entity. | Judgement required | <p>All facts and circumstances have to be considered before determining the classification. Assessment of the economic rationale behind such an arrangement might give an indication of the purpose and design of the arrangement.</p> <p>An assessment should be made of whether one of the parties actually controls the arrangement or if there is an IFRIC 4 arrangement involved.</p> <p>If it is concluded that there is joint control, it seems that the arrangement has some indicators of a joint operation. This is because the arrangement does not sell to third parties and is dependent on one of the parties for its continuous cash flows. However, one of the parties does not consume any output.</p> |

Re-assessment of classification

The rights and obligations of parties to joint arrangements might change over time. This might happen, for example, as a result of a change in the purpose of the arrangement that might trigger a reconsideration of the terms of the contractual arrangements. Consequently, the assessment of the type of joint arrangement needs to be a continuous process, to the extent that facts and circumstances change.

4.2.4 Accounting for joint operations (JOs)

Investors in a joint operation are required to recognise the following:

- its assets, including its share of any assets held jointly;
- its liabilities, including its share of liabilities incurred jointly;
- its revenue from the sale of its share of the output arising from the joint operation;
- its share of the revenue from the sale of the output by the joint operation;
- its expenses, including its share of any expenses incurred jointly

The share of assets and liabilities is not the same as proportionate consolidation. ‘Share of assets and liabilities’ means that the investor should consider their interest or obligation in each underlying asset and liability under the terms of the arrangement – it will not necessarily be the case that they have a single, standard percentage interest in all assets and liabilities.

An investor should not additionally account for its shareholding in joint operations. It should account for the activity of the JO in its own financial statements.

4.2.5 Accounting for joint ventures (JVs)

IFRS 11 requires equity accounting for all joint arrangements classified as joint ventures. Investors who previously had a choice between equity accounting and proportionate consolidation for a jointly controlled entity will no longer have that choice.

The key principles of the equity method of accounting are described in IAS 28 *Investments in associates and joint ventures*:

- investment in the JV is initially recognised at cost;
- changes in the carrying amount of investment are recognised based on the venturer's share of the profit or loss of the JV after the date of acquisition;
- the venturer only reflects their share of the profit or loss of the JV; and
- distributions received from a JV reduce the carrying amount of the investment.

The results of the joint venture are incorporated by the venturer on the same basis as the venturer's own results – i.e. using the same GAAP (IFRS) and the same accounting policy choices. The growing use of IFRS and convergence with US GAAP has helped in this regard but the basis of accounting should be set out in the formation documents of the joint venture.

Joint venture uses a different GAAP

A venture uses IFRS. Are accounting adjustments required before it can incorporate the results of a joint venture that reports under US GAAP?

Background

Entity J is a joint venture that prepares its accounts under US GAAP as prescribed in the joint venture agreement. One of the investors, entity C, prepares its consolidated financial statements under IFRS. C's management believes that for the purpose of applying the equity method, the US GAAP financial statements of J can be used.

Must C's management adjust entity J's US GAAP results to comply with IFRS before applying the equity method?

Solution

Yes. The results must be adjusted for all material differences. Para 17 of IAS 1 requires that all information contained in IFRS financial statements should be prepared according to IFRS. Para 36 of IAS 28 requires C's management to make appropriate adjustments to J's US GAAP results to make them compliant with IFRS requirements. There is no exemption in IFRS for impracticability.

4.2.6 Contributions to joint arrangements

Entities can make a policy choice in these types of transaction until the amendments to IFRS 10 and IAS 28 *Sale or contribution of assets between an investor and its associate and joint venture* are adopted or become effective.

Participants frequently contribute assets such as cash, non-monetary assets or a business to a joint arrangement on formation. Contributions of assets are a partial disposal by the contributing party. The party to the arrangement receives in return a share of the assets contributed by the other participants. Accordingly, the contributor should recognise a gain or loss on the partial disposal. The

gain is measured as the proportionate share of the fair value of the assets contributed by the other participants less the portion of the book value of the contributor's disposed asset now attributed to the other participants.

The participant recognises its share of an asset contributed by other participants at its share of the fair value of the asset contributed. For a joint operation this is classified in the balance sheet according to the nature of the asset. For a joint venture, 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 participants contributes a business to a joint arrangement; however, one of the assets recognised will normally be goodwill, calculated in the same way as in a business combination.

Contributions to jointly controlled entities

If a joint venture uses the fair value of all contributed assets in its own financial statements, can this be reflected in the venturer's own financial statements through equity accounting?

Background

Entities A and B have brought together their petrol stations in a certain region in order to strengthen their market position and reduce costs. They established entity J and contributed the petrol stations to J. A receives 60% of the shares in J, and entity B receives 40%.

Entity J has recognised the contribution of the petrol stations from entities A and B at fair value. Entity J is compelled to do this by local company law as shares issued must be backed by the fair value of assets recognised. Effectively, J follows the 'fresh start' method of accounting for its formation.

Entity A deems J to be a joint venture and accounts for its interest using the equity method. A's management wants to include its share of J's net assets and profits and losses on the same basis on which they are accounted for in entity J, without adjustment. They point out that Entity J has used an acceptable method under IFRS of accounting for its formation.

Entity A has not adopted the indefinitely deferred amendments to IFRS 10 and IAS 28 regarding contributions to a joint arrangement (discussed below).

Can A's management do this?

Solution

Yes, there is a policy choice available to A in certain circumstances because of the conflict in the accounting standards described below. A can choose partial recognition of the gain or loss, being the difference between 40% of the fair value of its petrol stations contributed and 40% of their carrying amount plus its 60% share of the fair value of the petrol stations contributed by B. This is the approach set out in IAS 28. A may also recognise 100% of the gain arising on its disposal of its petrol station business following IFRS 10 – see narrative below.

The example above is based on guidance provided in IAS 28, which was incorporated when IFRS 11 was written and incorporated the guidance that was in SIC-13 *Jointly controlled entities – non-monetary contributions by venturers*. There is an inconsistency between this guidance and IFRS 10

Consolidated financial statements when the contribution to the jointly controlled entity is considered to represent a business.

IFRS 10 has different guidance on the loss of control of a business. Any investment a parent has in the former subsidiary after control is lost is measured at fair value at the date that control is lost and any resulting gain or loss is recognised in profit or loss in full.

The IASB issued amendments to IFRS 10 and IAS 28 *Sale or contribution of assets between an investor and its associate and joint venture* in September 2014. Under these amendments the gain or loss on a contribution to the jointly controlled entity that represents a business should be recognised by the investor in full. As of the date of this publication, the mandatory effective date of the amendments is deferred indefinitely. Earlier application is allowed.

4.2.7 Investments with less than joint control

Some co-operative arrangements may appear to be joint arrangements 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 of each venturer. If an entity doesn't qualify as a joint venture, each investor will account for its investment either using equity accounting in accordance with IAS 28 (if it has significant influence) or at fair value as a financial asset in accordance with IAS 39.

An investor may also participate in a joint operation but not have joint control. The investor should account for their rights to assets and obligations for liabilities. If they do not have rights to assets or obligations for liabilities they should account for their interest in accordance with the IFRS applicable to that interest.

Investors may have an undivided interest in a tangible or intangible asset where there is no joint control and the investors 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 a shared pipeline network and an investor with a 20% interest has the right to use the network. 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.

Identifying a joint venture

Is an entity automatically a joint venture if more than two parties hold equal shares in an entity?

Background

Entity A, B, C and D (venturers) each hold 25% in entity J, which owns a refinery. Decisions in J need to be approved by a 75% vote of the venturers.

Entity A's management wants to account for its interest in J using proportional consolidation in its IFRS consolidated financial statements because J is a joint venture. Can A's management account for J in this way?

Solution

No. A cannot account for J using its share of revenue and assets because J is not jointly controlled. The voting arrangements would require unanimous agreement between those sharing the joint control of J to qualify as a joint venture. The voting arrangements of J allow agreement of any combination of three of the four partners to make decisions.

Each investor must therefore account for its interest in J as an associate since they each have significant influence but they do not have joint control. Equity accounting must therefore be applied.

4.2.8 Changes in ownership in a joint arrangement

The IASB issued amendments to IFRS 10 and IAS 28 *Sale or contribution of assets between an investor and its associate and joint venture* in September 2014. Under these amendments the gain or loss on a contribution to the jointly controlled entity that represents a business should be recognised by the investor in full. The gain or loss on a contribution that does not represent a business should be recognised to the extent of the unrelated investors' interest in the joint venture. As of the date of this publication, the effective date of the amendments has been deferred indefinitely. Earlier application is allowed.

A participant in a joint arrangement may increase or decrease its interest in the arrangement. The appropriate accounting for an increase or decrease in the level of interest in the joint arrangement will depend on the type of joint arrangement and on the nature of the new interest following the change in ownership.

Changes in ownership – Joint operations

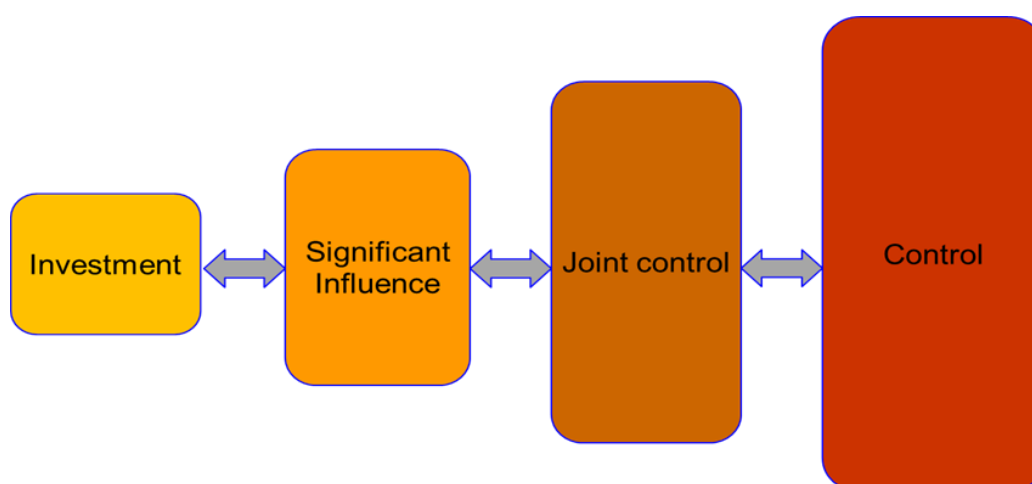
The accounting for a change in the ownership will depend on whether the assets under the arrangement represent a business and the level of control which exists after the change in ownership. If the operation meets the definition of a business and control is obtained, this represents a business combination and the pre-existing interest held will be considered disposed of and revalued to its fair value. The accounting for business combinations is discussed in section 4.1. If control is not obtained and the asset remains jointly controlled, the consideration paid for any additional interest is capitalised as the cost of that interest.

Reductions in the interest in jointly controlled assets will result in derecognising an amount of carrying value equivalent to the proportionate share disposed, regardless of whether joint control remains or not.

Changes in ownership – Joint ventures

Accounting for increases in interest in a joint venture will depend on the level of control post acquisition. If control is obtained, a business combination has taken place. The carrying amount previously recognised under equity accounting or share of assets and liabilities would be derecognised, acquisition accounting applies and the entity would be fully consolidated. This would require a fair value exercise, remeasurement of the previously held interest and measurement of non-controlling interest and goodwill. There may also be a gain or loss to recognise in the income statement.

A partial disposal of an equity accounted interest that results in no change in joint control or a change to significant influence results in the entity derecognising a proportion of the carrying amount of the investment. It will recognise any gain or loss arising on the disposal in the income statement. The entity does not remeasure the retained interest.



4.2.9 Accounting by the joint arrangement

The preceding paragraphs describe the accounting by the investor in a joint venture.

Accounting by the joint venture

The joint venture itself will normally prepare its own financial statements for reporting to the joint venture partners and for statutory and regulatory purposes. 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 or businesses to the joint venture in exchange for their equity interest in the JV. An asset contributed to a joint venture in exchange for issuing shares to a venturer is a transaction within the scope of IFRS 2 *Share-based payments*. These assets are recognised at fair value in the financial statements of the joint arrangement. However, the accounting for the receipt of a business contributed by a venturer is not specifically addressed in IFRS as it is outside the scope of IFRS 2 and IFRS 3.

Two approaches have developed in practice. 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.

Accounting by the joint operation

The joint operation needs to reflect rights and obligations of operators in JO's reported assets and liabilities.

4.2.10 Farm outs

A 'farm out' occurs when a venturer (the 'farmor') assigns an interest in the reserves and future production of a field to another party (the 'farmee'). This is often in exchange for an agreement by the farmee to pay for both its own share of the future development costs and those of the farmor. There may also be a cash payment made by the farmee to the farmor. This is a "farm in" when considered from the farmee's perspective. This typically occurs during the exploration or development stage and is a common method entities use to share the cost and risk of developing properties. The farmee hopes that their share of future production will generate sufficient revenue to compensate them for performing the exploration or development activity.

Accounting by the farmor

Farm out agreements are largely non-monetary transactions at the point of signature for which there is no specific guidance in IFRS. Different accounting treatments have evolved as a response. The accounting depends on the specific facts and circumstances of the arrangement, particularly the stage of development of the underlying asset.

Assets with proven reserves

If there are proven reserves associated with the property, the farm-in should be accounted for in accordance with the principles of IAS 16. The farm out will be viewed as an economic event, as the farmor has relinquished its interest in part of the asset in return for the farmee delivering a developed asset in the future. There is sufficient information for there to be a reliable estimate of fair value of both the asset surrendered and the commitment given to pay cash in the future.

The rights and obligations of the parties need to be understood while determining the accounting treatment.

The consideration received by the farmor in exchange for the disposal of their interest is the value of the work performed by the farmee plus any cash received. This is presumed to represent the fair value of the interest disposed of in an arm's length transaction.

The farmor should de-recognise the carrying value of the asset attributable to the proportion given up, and then recognise the 'new' asset to be received at the expected value of the work to be performed by the farmee. After also recording any cash received as part of the transaction, a gain or loss is recognised in the income statement. The asset to be received is normally recognised as an intangible asset or 'other receivable'. When the asset is constructed, it is transferred to property, plant and equipment.

Assessing the value of the asset to be received may be difficult, given the unique nature of each development. Most farm out agreements will specify the expected level of expenditure to be incurred on the project (based on the overall budget approved by all participants in the field development). The agreement may contain a cap on the level of expenditure the farmee will actually incur. The value recognised for the asset will often be based on this budget. A consequence is that the value of the asset will be subject to change as the actual expenditure is incurred, with the resulting adjustments affecting the gain or loss previously recognised. The stage of development of the asset and the reliability of budgeting will impact the volatility of subsequent accounting.

Assets with no proven reserves

The accounting is not as clear where the mineral asset is still in the exploration or evaluation stage. The asset would still be subject to IFRS 6 *Exploration for and evaluation of mineral resources* rather than IAS 16. The reliable measurement test in IAS 16 for non-cash exchanges may not be met. Neither IFRS 6 nor IFRS 11 gives specific guidance on the appropriate accounting for farm outs.

Several approaches have developed in practice by farmers:

- recognise only any cash payments received and do not recognise any consideration in respect of the value of the work to be performed by the farmee and instead carry the remaining interest at the previous cost of the full interest reduced by the amount of any cash consideration received for entering the agreement. The effect will be that there is no gain recognised on the disposal unless the cash consideration received exceeds the carrying value of the entire asset held;
- follow an approach similar to that for assets with proven reserves, recognising both cash payments received and value of future asset to be received, but only recognise the future asset when it is completed and put into operation, deferring gain recognition until that point; or
- follow an approach similar to that for assets with proven resources, recognising both cash payments received and value of future asset to be received, and recognise future asset receivable when the agreement is signed with an accompanying gain in the income statement for the portion of reserves disposed of.

All three approaches are used today under current IFRS. There can be volatility associated with determining the value of the asset to be received as consideration for a disposal in a farm out of assets with proven resources. This volatility is exacerbated for assets which are still in the exploration phase. Prevalent industry practice follows the first approach outlined above.

Accounting by the farmee

The farmee will only recognise costs as incurred, regardless of the stage of development of the asset.

The farmee is required to disclose its contractual obligations to construct the asset and meet the farmor's share of costs.

The farmee should follow its normal accounting policies for capitalisation, and also apply them to those costs incurred to build the farmor's share.

Accounting for a farm out

Background

Company N and company P participate jointly in the exploration and development of an oil and gas deposit located in Venezuela. Company N has an 18% share in the arrangement, and company B has an 82% share. Companies N and P have signed a joint arrangement agreement that establishes the manner in which the area should operate. N and P have a joint operation under IFRS 11. The assets of the joint operation comprise the oil and gas field, machinery and equipment. There are no proven reserves.

The companies have entered into purchase and sale agreements to each sell 45% of their participation to a new investor – company R. Company N receives cash of C4 million and company P receives cash of C20 million. The three companies entered into a revised ‘joint development agreement’ to establish the rights and obligations of all three parties in connection with the funding, development and operations of the asset.

The composition of the interests of the three companies is presented in the table below:

| | Company N | Company P | Company R | Total |
|---------------------------|------------|-------------|-----------|-------------|
| Before transaction | 18% | 82% | – | 100% |
| After transaction | 10% | 45% | 45% | 100% |
| Cash received | C4 million | C20 million | – | C24 million |

Each party to the joint development agreement is liable in proportion to their interest for costs subsequent to the date of the agreement. However, 75% of the exploration and development costs attributable to companies N and P must be paid by company R on their behalf. The total capital budget for the exploration and development of the asset is C200 million. Company N’s share of this based on its participant interest would be C20 million; however, company R will be required to pay C15 million of this on behalf of company N.

The carrying value of the asset in Company N’s financial statements prior to the transaction was C3 million.

Question

How should company N account for such transaction?

Solution

This transaction has all the characteristics of a farm out agreement. The cash payments and the subsequent obligation of company R to pay for development costs on behalf of companies N and P appear to be part of the same transaction. Companies N and P act as farmers and company R acts as the farmee. The structure described is a joint operation. Company N should account for its share of the assets and liabilities and share of the revenue and expenses.

The gain on disposal could be accounted for by company N using one of three approaches, as follows:

1. Recognise only cash payments received.

Company N will reduce the carrying value of O&G asset by the C4 million cash received. The C1 million excess over the carrying amount is credited to the income statement as a gain. The C15 million of future expenditure to be paid by company R on behalf of company N is not recognised as an asset. As noted above, this approach would be consistent with common industry practice.

2. Recognise cash payments plus the value of the future assets at the agreement date.

Company N will recognise the C4 million as above. In addition, it will recognise a 'receivable' or intangible asset for the future expenditure to be incurred by company R on company N's behalf, with a further gain of this amount recognised in the income statement. Company N would have to assess the expected value of the future expenditure. Although one method to estimate this would be the budgeted expenditure of C15 million, company N would need to assess whether this would be the actual expenditure incurred. Any difference in the final amount would require revision to the asset recognised and also the gain, creating volatility in the income statement.

3. Recognise cash payment plus the value of future assets received when construction is completed.

Company N will recognise the C4 million cash received as in '1.' above. When the future assets are completed, these are recognised in the balance sheet, and a gain of the same amount is recognised in the income statement. This approach would avoid the volatility issue associated with approach '2'.

4.2.11 Unitisation agreements

Unitisation usually occurs in the exploration or development stage of O&G assets. Entities may own assets or exploration rights in adjacent areas, and enter into a contract to combine these into a larger area and share the costs of exploration, development and extraction. The entity will receive in exchange a share of the expected future output of the larger area. The unitised field is usually a joint operation. Unitisations are often required by governments to reduce the overall cost of extraction through a more efficient deployment of infrastructure.

The share of output allocated to each participant will depend on the contribution their existing asset made to the total production of this area. This is known as a 'unitisation'. A preliminary assessment of the allocated interest is made on the initial unitisation and the entity will be responsible for future expenditure for the area in accordance with its allocated interest. The interest will be subsequently amended as more certainty is obtained over the final output of each component and redeterminations are made. Adjustments to future production entitlement or cost contributions may be made accordingly. Cash payments may be made between the participants where there is insufficient production or development remaining to true up contributions to date.

The initial unitisation is accounted for as a contribution of assets. No change is recorded in the carrying amount of existing interests unless cash payments have been made on unitisation. The value of the asset being received is equivalent to the value of the asset being given up. If a cash payment has

been paid or received, it is adjusted against the carrying value of the oil and gas asset. This will also be the case when a redetermination of the unitisation is performed.

The unitisations and redeterminations will also affect the relevant reserves base to be used for the purposes of the DD&A calculation. The carrying value of the oil and gas asset is depreciated over any revised share of reserves on a prospective basis. The entity will also be required to reassess the decommissioning obligation associated with the asset.

Redetermination of a unitisation

How should an entity account for a redetermination of a unitisation?

Background:

Company A and B owned the adjoining oil prospects Alpha and Delta respectively. Both prospects were in the exploration phase with no proven reserves. The companies entered into an agreement to develop the prospects jointly and the combined area, Omega, which is considered to be a joint operation. The initial unitisation agreement stated that each was entitled to 50% of the output of the combined area. This allocation was subject to future redetermination when the exploration of Alpha and Delta was complete and proven reserves were determined. Additional redetermination would take place on an ongoing basis after that as production commenced and reserve estimates were updated.

The exploration of the two prospects was completed. Both were found to have proven reserves and based on these results the following redetermination was performed:

| | Company A | Company B | Total |
|---------------------------------------|------------|------------|-------------|
| Initial unitisation | 50% | 50% | 100% |
| Redetermination | 40% | 60% | 100% |
| Exploration cost to date | C5 million | C5 million | C10 million |
| Future development expenditure | | | C40 million |

The companies have agreed that they will take a share of future production in line with the new determination of interests. Additionally, the true-up of costs incurred to date will be made via adjustments to future expenditure rather than an immediate cash payment.

Prior to redetermination company A had capitalised the C5 million cost incurred as an exploration asset, and transferred this to tangible assets when proven reserves were discovered. How should company A account for this redetermination?

Solution

Company A has incurred expenditure of C1 million greater than the share required by the revised allocation of interest. In theory, it has a C1 million receivable from company B. The agreement between the companies indicates that this will be true-up via adjustment to future development expenditure i.e. company A will only be responsible for C15 million of future spend rather than C16 million (C40 million*40%). It would be appropriate for company A to retain this C5 million asset as a development asset with no adjustment for the C1 million. It should consider whether the change in the reserve estimates indicates any impairment has occurred in the carrying value of the

asset. Based on the revised share of future production and the development costs still to come, impairment would be unlikely.

4.3 Production sharing agreements (PSAs)

4.3.1 Overview

The effect of new revenue standard IFRS 15 on the accounting for PSAs is discussed in section 7.2.2. IFRS 15 is effective on 1 January 2018.

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 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. There are as many forms of PSA and royalty agreements as there are combinations of national, regional and municipal governments in oil producing areas.

An oil and gas entity in a typical PSA will undertake exploration, supply the capital, develop the resources found, build the infrastructure and lift the natural resources. The oil and gas entity (usually referred to as the operator) will have the right to extract resources over a specified period of time; this is typically the full production life of the field such that there would be minimal residual value of the asset at the end of the PSA. The terms of the PSA are likely to include asset decommissioning requirements. The oil and gas entity will be entitled to a share of the oil produced which will allow the recovery of specified costs ('Cost oil') plus an agreed profit margin ('Profit oil'). The government will retain title to all of the hydrocarbon resources and often the legal title to all fixed assets constructed to exploit the resources.

The residual value of the fixed assets in most cases would be minimal and the operator would decommission them under the terms of the PSA. The company is viewed as having acquired the right to extract the oil in the future when it performs the development work under the PSA. The development expenditure is capitalised according to the requirements of IFRS 6 and IAS 16.

The government will take a substantial proportion of the output in PSAs. The oil may be delivered in product or paid in cash under an agreed pricing formula.

An entity should consider its overall risk profile in determining whether it has a service agreement or a working interest. Certain PSAs may be more like service arrangements whereby the government compensates the entity for exploration, development and construction activities. These are arrangements where the PSA is substantially shorter than the expected useful life of the production asset or are explicit cost plus arrangements. The entity thus bears the risks of performing this contract rather than traditional exploration and development risks. Expenditure incurred on the exploration and development plus a profit margin is usually capitalised as a receivable from the government rather than an interest in the future production of the field.

A concession or royalty agreement is much the same as a PSA arrangement where the entity bears the exploration risk. The entity will usually retain legal title to its assets and does not directly 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 concession agreements 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 PSA 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 royalty agreements based on changes in market conditions or environmental factors.

The PSA 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 considered when estimating the life of the agreement.

The legal form of the PSA or concession should not impact the principles underpinning 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 accounting policies where the entity is exposed to the majority of the economic risks and has access to the probable future economic benefits of the assets.

4.3.2 Entity bears the exploration risk

Cost capitalisation

The entity follows a similar approach to non-PSA projects when it bears the exploration risk of the contract. It will capitalise expenditure in the exploration and development phase in accordance with the requirements of IFRS 6, IAS 16 and IAS 38.

The reserves used for depreciating the constructed assets should be those attributable to the reporting entity for the period of the PSA or concession. 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.

A PSA is usually a separate CGU for impairment testing purposes once in production. The entity tests for impairment during the exploration and evaluation phase using the guidance in IFRS 6. Once in the development and production phases the guidance in IAS 36 applies.

Offshore field PSA for 25 years

The legal form of the PSA should not impact the recognition of exploration and evaluation (E&E) assets or production assets. How should those assets be accounted for?

Background

Entity A is party to a PSA related to an offshore field. The term of the agreement is 25 years. Entity A will operate the assets during the term of the PSA but the government retains title to the assets constructed. A is entitled to full cost recovery. However, if the resources produced in the future do not cover the costs incurred, the government will not reimburse A.

Entity A's management proposes to account for the expenditure as a financial receivable rather than as property, plant and equipment because the government is retaining the title of the assets constructed. Is this appropriate?

Solution

No. Entity A controls the assets during the life of the PSA through its right to operate them. The construction costs that meet the recognition criteria of IFRS 6, IAS 38 or IAS 16 should be recognised in accordance with those standards:

- where the entity is exposed to the majority of the economic risks and has access to the probable future economic benefits of the assets; and

- the period of the PSA is longer than the expected useful life of the majority of the constructed assets; and
- the probable mineral resources at current prices provide evidence that E&E, development and fixed asset investment will be recovered through the cost recovery regime of the PSA.

All assets recognised are then accounted for under entity A's usual policies for subsequent measurement, depreciation, amortisation, impairment testing and de-recognition. The assets should be fully depreciated or amortised on a units-of-production basis by the date that the PSA ends.

Revenue recognition

In PSAs where an entity bears the exploration risk, it will record its share of oil or gas as revenue (both cost oil and profit oil) only when the oil or gas is produced and sold.

The entity records revenue only when oil production commences and only to the extent of the oil to which it is entitled and sells. 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.

An entity follows the same approach to revenue recognition for royalty agreements.

Revenue in PSAs (1)

How is revenue recognised under a PSA?

Background

The upstream company (or contractor) typically bears all the costs and risks during the exploration phase. The government (or the government-owned oil company) shares in any production. The upstream company generally receives two components of revenue; cost oil and profit oil. Cost oil is a 'reimbursement' for the costs incurred in the exploration phase and some (or all) of the costs incurred during the development and production phase. Profit oil is the company's share of oil after cost recovery or as a result of applying a profit factor. The PSA typically specifies, among other items, which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period.

Total revenue of the PSA is recognised upon the delivery of the volumes produced to a third party (i.e. the purchaser of the volumes) based on the price as set forth in the PSA. The price could be either a market-based price or a fixed price depending on the specific terms of the PSA. The revenue of the PSA is then split between the parties based on the specific sharing terms of the PSA. The formation of a PSA does not commonly create an entity that would qualify as a joint venture under IFRS.

The issue is not usually recognition of revenue – the oil has been delivered to third parties and the criteria in IAS 18 paragraph 14 are met. The question is how the revenue from oil sold should be split between the operator, the government oil company and any others.

Solution

The operator is entitled to the oil it has earned as reimbursement for costs (exploration and its share of development and production) and its share of profit oil. The government's share of oil does not form part of revenue even if the operator collects the funds and remits them to the

government oil company. Any royalties or excise taxes that are collected on behalf of the government or any other agency of the state do not form revenue of the operator because of the explicit guidance in IAS 18 paragraph 8.

Revenue in PSAs (2)

How is revenue in a PSA split between the participating interests?

Solution:

The example below sets out how the revenue from a PSA is split between the operator, the government oil company and the taxation authorities. The government's royalty is 10% of production, the operator has a profit share of 55% and the government oil company's share is 45%. Cost oil is limited to 60% after the government's royalty; any unrecovered costs can be carried forward to future years.

Cost oil components in order of priority are:

- 1) operating expenses (share based on profit share;
- 2) exploration costs (all incurred by the operator);
- 3) development costs (share based on profit share percentage); and
- 4) profit oil.

Assumptions:

| | |
|---|-----------|
| Exploration costs incurred | \$50,000 |
| Development costs incurred in Y1 | \$80,000 |
| Operating costs in Y1 | \$450,000 |
| Production volumes (same as volumes sold) | 30,000 |
| Price | \$97.00 |

| | Total | Gov | Upstream com | GOE |
|--------------------------------|--------------|------------|-------------------------|------------|
| Revenue | \$2,910,000 | | | 100% |
| Royalty (10%) | \$291,000 | \$291,000 | | |
| Remaining | \$2,619,00 | | | |
| Limit on cost oil (60%) | \$1,571,400 | | | |
| Cost oil: | | | | |
| Operating | \$450,000 | | \$247,500 | \$202,500 |

| | | | | |
|---------------------------|-------------|-----------|-------------|-------------|
| Exploration | \$50,000 | | \$50,000 | – |
| Development | \$80,000 | | \$44,000 | \$36,000 |
| Total cost oil | \$580,000 | | \$341,500 | \$238,500 |
| Profit oil | \$2,039,000 | | \$1,121,450 | \$917,550 |
| Total revenue | \$2,910,000 | \$291,000 | \$1,462,950 | \$1,156,050 |
| Applicable volumes | 30,000 | 3,000 | 15,082 | 11,918 |

The above example is a simple example of the allocation methodology. The applicable volumes are determined by dividing the allocated revenue by the price of the volumes sold.

4.3.3 Entity bears the contractual performance risk

Cost capitalisation criteria

An entity may be primarily exposed to performance risk rather than reserves risks under a PSA. The entity can continue to capitalise E&E and development costs, but although the costs of constructing the fixed assets are capitalised, they are not classified as PPE. The entity instead would 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/IFRS 9 rather than IAS 16.

Impairment assessment

The asset recognised will be accounted as a receivable. Therefore, the impairment testing rules on financial assets in IAS 39/IFRS 9 would be applicable.

Revenue recognition

If the entity bears the risks of performing the contract rather than the actual exploration activity, expenditure incurred on the exploration and development of the asset is capitalised as a receivable from the government rather than as a fixed asset. When the outcome of the contract can be reliably estimated, the percentage of completion method will be used to determine the amount of revenue to be recognised. The expected profit margin will be included in this calculation.

Revenue in PSAs (3)

Background

Government 'V' believes they might find oil reserves on the western coast of the country, designated 'Beta'. After the process, entity 'A' was awarded with the offshore block. The government and company A signed a 15-year PSA to explore, develop and exploit this block under the following terms:

- Company 'A' will undertake exploration, development and production activities. Government 'V' will remunerate A for performance of the contracted construction services regardless of the success of the exploration and hold title to the assets constructed.
- National law indicates that the title of all hydrocarbons found in the country remains with government 'V'.
- Government 'V' will reimburse for all expenditures incurred by company 'A' at the following milestones: – Completion of seismic study programme
 - Approval of exploration work programme
 - Completion of development work programme
 - Commencement of commercial productionme
- Reimbursement is based on approved costs incurred plus an uplift of 5%.
- Reimbursement will be performed in the form of oil produced. Quantities provided will be based on market price. Where insufficient quantities are produced, the government can settle the amount due in cash or oil from another source.

How will entity 'A' recognise revenue on this project?

Solution

The terms of the agreement are such that company A carries a 'contract performance' risk rather than bearing the risk of exploration. Accordingly, costs will be capitalised as a recoverable from the government. There are multiple performance obligations within the agreement, and the company can only recognise revenue as each of these obligations is achieved. As the terms provide that approved costs can be recovered with a 5% uplift, the company will initially carry the costs incurred as work in progress. When the entity is able to reliably estimate the outcome of the contract, it may use the percentage of completion method to recognise revenue, which will include the expected uplift of 5% on costs incurred.

4.3.4 Decommissioning in PSAs

Decommissioning of oil and gas production assets may be required by law, the terms of operating licences or an entity's stated policy and past practice. All of these create an obligation and thus a liability under IFRS.

PSAs sometimes require that a decommissioning fund be created with the objective of settling decommissioning costs to be incurred in the future. The PSA may require that contributions to these funds be made by participating entities on an annual basis until the date of decommissioning or allow them to be made on a voluntary basis prior to the decommissioning date.

The decommissioning arrangements can have a number of structures:

- the operating entity is expected to perform the decommissioning activity using the established fund;
- the participating entities are required to pay for the decommissioning activity and claim for reimbursement from the fund; and

- the government has the right to take control of the asset at the end of the PSA term (there may still be reserves to produce), take over the decommissioning obligation and be entitled to the decommissioning fund established.

IFRIC 5 is applicable to funds which are both administered separately and where the contributor's right to access the assets is restricted.

The participants should recognise their obligation to pay the decommissioning costs as a liability and recognise their interest in the decommissioning fund separately. They should determine the extent of their control over the fund (full, joint or significant influence) and account for their interest in the fund in accordance with the relevant accounting standard.

4.3.5 Taxes on PSAs

A crucial question arises about the taxation of PSAs – when are amounts paid to the government as an income tax (part of revenue), when are amounts a royalty (excluded from revenue) and when are amounts to be treated as a production cost. 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?

Classification as income tax or royalty

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 net 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.

Classification of profit oil as income tax or royalty (1)

The upstream company or operator generally receives two components of revenue, most often described as cost oil and profit oil. Cost oil is calculated as a 'reimbursement' for the costs incurred in the exploration phase and some (or all) of the costs incurred during the development and production phase. Profit oil is the company's share of oil after cost recovery or as a result of applying a profit factor. The PSC typically specifies, among other items, which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period (see section 4.3.2 for a worked example).

Is a share of profit oil an income tax or royalty?

Background

Mammoth Oil has a PSC in Small Republic in Africa. The PSC agreement calls for a 10% royalty of gross proceeds of all revenue to be paid to the Ministry of Taxation. The cost oil is calculated as 10% of exploration costs, plus 10% of costs of production assets plus all current operating costs subject to a ceiling. The profit oil is then split 50% to Mammoth and 50% to the National Oil

Company. The PSC calls for a further payment to the National Oil Company if Mammoth's share of profit oil exceeds its cost oil and is calculated at 10% of the excess in these circumstances.

Management has deemed the further payments as an income tax because it is calculated on a formula that includes items described as profit and costs. The amounts are included in revenue and income tax expense. Is this treatment appropriate?

Solution

No. The further payment by the National Oil Company is simply a further apportionment of the profit oil and thus is excluded from revenues. It may be described as an 'income tax' in the PSC but it is not an income tax as described in IAS 12.

Classification of profit oil as income tax or royalty (2)

The upstream company or operator generally receives two components of revenue, most often described as cost oil and profit oil. Cost oil is calculated as a 'reimbursement' for the costs incurred in the exploration phase and some (or all) of the costs incurred during the development and production phase. Profit oil is the company's share of oil after cost recovery or as a result of applying a profit factor. The PSC typically specifies, among other items, which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period (see section 4.3.2 for a worked example).

Is a share of profit oil an income tax or royalty?

Background

Mammoth Oil has a PSC in Utopia. The PSC agreement calls for a 10% royalty of gross proceeds of all revenue to be paid to the Ministry of Taxation. The cost oil is calculated as 10% of exploration costs, plus 10% of costs of production assets plus all current operating costs subject to a ceiling. The profit oil is then split 50% to Mammoth and 50% to the National Oil Company.

The PSC is explicit that the operations of Mammoth Oil in Utopia are subject to the tax rules and regulation of Utopia. The company files a tax return and pays income tax under the normal tax rules. The tax regulations include a 10% surcharge on any income tax that is due under the ordinary tax rules. The PSC requires the National Oil Company to pay this surcharge on behalf of Mammoth and notify Mammoth that it has been paid. The tax counsel of Mammoth has legal advice that Mammoth is liable for the tax until it is paid; if the National Oil Company does not pay, Mammoth must pay the tax and then attempt to recover it from National Oil Company.

Management has deemed this an income tax and is including it in revenue and income tax expense. Is this treatment appropriate?

Solution

Yes. The payment by the National Oil Company qualifies as an income tax. It is based on taxable profits as defined in the tax code. Mammoth Oil is liable for the tax until it is paid by National Oil Company. It is appropriately included as revenues and income tax expense. The tax rate used to calculate deferred tax assets and liabilities should include the amount of the tax surcharge. The fact

that the government calls the payment ‘a royalty’ does not determine the accounting; it is the nature of the payment that is relevant to its classification.

Tax paid in kind

Many PSAs specify that income taxes owed by the entity are to be 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. Volume-based levies are usually accounted for as royalty or excise tax within operating results. See section 4.6 for further details.

‘Tax paid on behalf’ (POB)

POBs can arise under a PSA where the upstream entity is the operator of fields and the government entity is the national oil company that holds the government’s interest in the PSA. POB arrangements are varied, but generally arise when the government entity will pay the income tax due by the foreign upstream entity to the government on behalf of the foreign upstream entity. The crucial issue in accounting for tax POB arrangements is to determine 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, under a tax holiday scenario, 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 in section 4.6.3 *Taxes paid in cash or in kind*.

4.4 Decommissioning

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 or has done so in the past, 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 arise during the operating life of an installation. The associated costs of remediation/restoration can be significant. The accounting treatment for decommissioning costs is therefore critical.

4.4.1 Decommissioning provisions

A provision is recognised when an obligation exists to perform the clean-up [IAS 37 para 14]. 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. However, there is some diversity in practice as to whether the entire expected liability is recognised when activity begins, or whether it is recognised in increments as the development activity progresses. There is also diversity in whether decommissioning liabilities are recognised during the exploration phase of a project. The asset and liability recognised at any particular point in time needs to reflect the specific facts and circumstances of the project and the entity’s obligations.

Decommissioning provisions are measured at the present value of the expected future cash flows that will be required to perform the decommissioning [IAS 37 para 45]. The obligation does not change in substance if the platform produces 10,000 barrels or 1,000,000.

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 [IAS 16 para 16(c)]. 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 (typically UOP). 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.

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. The future cash flows expected to be incurred in performing the decommissioning may be denominated in a foreign currency. When this is relevant the foreign currency future cash flows should be discounted at a rate relevant for that currency. The present value is translated into the entity's functional currency using the exchange rate at the balance sheet date.

4.4.2 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 [IAS 37 para 59]. This includes changes in the exchange rate when some or all of the expected future cash flows are denominated in a foreign currency. 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 [IFRIC 1 para 5] However, the adjustments to the asset are restricted. The asset cannot decrease below zero and cannot increase above its recoverable amount [IFRIC 1 para 5]:

- if the decrease in 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.

4.4.3 Deferred tax on decommissioning provisions

The amount of the asset and liability recognised at initial recognition of decommissioning are generally viewed as being outside of scope of the current 'initial recognition exemption (IRE)' in IAS 12 [paras 15 and 24]. The amount of accretion in the provision from unwinding of the discount gives rise to a book/tax difference and will result in a further deferred tax asset, subject to an assessment of recoverability. The IFRS IC considered a similar question at its April and June 2005 meetings of whether the IAS 12 IRE applied to the recognition of finance leases. IFRS IC acknowledged that there was diversity in practice in the application of the IRE for finance leases but decided not to issue an interpretation because of the IASB's short-term convergence project with the FASB. Accordingly, some entities might take an alternative view that the IAS 12 IRE should be applied for finance leases and decommissioning liabilities. However, a consistent policy should be adopted for deferred tax accounting for decommissioning liabilities and finance leases [IAS 8 para 13].

4.4.4 Decommissioning funds

Many oil and gas entities contribute to a separate fund established to help fund decommissioning and environmental obligations. These funds may be required by regulation or law or may be voluntary.

Typically, a fund is separately administered by independent trustees who invest the contributions received by the fund in a range of assets, usually debt and equity securities. The trustees determine how contributions are invested, within the constraints set by the fund's governing documents, and any applicable legislation or other regulations. The oil and gas entity then obtains reimbursement of actual decommissioning costs from the fund as they are incurred. However, the oil and gas entity may only have restricted access or no access to any surplus of assets of the fund over those used to meet eligible decommissioning costs.

IFRIC 5 *Rights to interests arising from decommissioning, restoration and environmental rehabilitation funds* provides guidance on the accounting treatment for these funds in the financial statements of the oil and gas entity. Management must recognise its interest in the fund separately from the liability to pay closure and environmental costs. Offsetting is not appropriate unless the contributor is not liable to pay decommissioning costs even if the fund fails to pay.

Management must determine whether it has control, joint control or significant influence over the fund and account for the fund accordingly. In the absence of these, rights to receive assets of the fund are accounted for as a reimbursement of the entity's closure and environmental obligation, at the lower of the amount of the decommissioning obligation recognised and the entity's share of the fair value of the net assets of the fund.

Any movements in a fund accounted for as a reimbursement are recognised in the income statement. The movements in the fund (based on the IFRIC 5 measurement) are assessed separately from the measurement of the provision (under IAS 37).

Accounting for performance guarantees

Background

In Ukraine, upstream gas entity A's subsidiary has recognised a closure and rehabilitation provision in respect of an abandonment liability for a field.

Entity A has also been required by law to place a parental performance guarantee equivalent to the estimated total amount required to fulfil the abandonment liabilities at the end of the life of the field it operates.

How should entity A account for this performance guarantee?

Solution

The performance guarantee should be disclosed in the consolidated financial statements as security for the obligation. The related decommissioning liability has already been accounted for under IAS 37.

4.4.5 Termination benefits

Payments made to employees in connection with the closure of a field must be accounted for under IAS 19 *Employee benefits*.

If it is certain that a field's hydrocarbon reserves will be exhausted at the end of the life of the field, it often follows from this that redundancy costs will arise unless employees can be relocated to other projects.

IAS 19 restricts when termination benefits can be recognised, with a liability only recognised when the entity is demonstrably committed to the redundancies by having:

- a detailed formal plan for the terminations; and
- no realistic possibility of withdrawal.

IAS 37 also sets out criteria for when a 'restructuring provision' can be accrued which requires a constructive obligation to arise.

Termination benefits can generally only be recognised when the closure date has been announced, specific plans are established, and other recognition criteria are met.

4.5 Impairment of development, production and downstream assets

4.5.1 Overview

The oil and gas industry is distinguished by the significant capital investment required and volatile commodity prices. 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 [IAS 36 para 9]. 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 2.3.7.

Impairments are recognised if a CGU's carrying amount exceeds its recoverable amount [IAS 36 para 6]. Recoverable amount is the higher of fair value less costs to sell (FVLCO) and value in use (VIU).

4.5.2 Impairment indicators

Entities must use judgement in order to assess whether an impairment indicator has occurred. If an impairment indicator is concluded to exist, IAS 36 requires that the entity perform an impairment test.

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

Impairment indicators (1)

Is a decline in market prices of oil and gas always an indicator of impairment?

Background

An entity has producing oil and gas fields. There has been a significant decline in the prices of oil and gas during the last six months.

Is such a decline in the prices of oil and gas an indicator of impairment of the field?

Solution

Price decreases are not automatically impairment indicators. The nature of oil and gas assets is that they often have a long useful life and the price point at which producing fields become uneconomic varies widely. Commodity price movements can be volatile and move between troughs and spikes.

Price reductions can assume more significance over time. If a decline in prices is expected to be prolonged and for a significant proportion of the remaining expected life of the field, an impairment indicator will likely have occurred.

Short-term market fluctuations may not be impairment indicators if prices are expected to return to higher levels within the near future. Such assessments can be difficult to make, with price forecasts becoming difficult where a longer view is taken. Entities should approach this area with care. In particular, entities should consider any downward movements carefully for fields which are high cost producers.

Impairment indicators (2)

Might a change in government be an indicator of impairment?

Background

An upstream company has a production sharing contract (PSC) in a small country in equatorial Africa. The company's investment in the PSC assets is substantial. There is a coup in the country and the democratically elected government is replaced by a military regime. Management of the national oil company (NOC), partner in the PSC, is replaced. The NOC has been paying income tax on behalf of the operator of the PSC.

New management of the NOC announces that it will no longer pay the income taxes on behalf of the operator. The operator will be required to pay income taxes and the petroleum excess profits tax from its share of the PSC profit oil. The combined effective tax rate is 88%.

The operator of the PSC expects that operating costs will increase principally due to increased wages and bonuses for expatriate employees and will not be recovered under the terms of the PSC.

Does the change in government constitute an indicator of impairment?

Solution

Yes. The change in government is a change in the legal and economic environment that will have a substantial negative impact on expected cash flows. The PSC assets should be tested for impairment.

Impairment indicators (3)

What are some common potential indicators of impairment in the oil and gas industry?

Solution

- significant reductions in estimates of reserves;
- a significant decline in the market capitalisation of the entity or other entities producing the same commodity;
- a decline in long-term market prices for oil and gas;
- a significant adverse movement in foreign exchange rates;
- a significant increase in production costs;
- a large cost overrun on a capital project such as an overrun during the development and construction of new wells;
- operation issues which may require significant capital expenditure to remediate;
- a significant increase in the expected cost of dismantling assets and restoring the site, particularly towards the end of a field's life;
- a significant revision of the plan for the development of the field;
- significant reductions in estimates of probable reserves;
- production difficulties;
- problems with securing infrastructure necessary to transport product to market;
- adverse changes in government regulations and environmental law, including a significant increase in the tax or royalty burden payable;
- increased security or political risk for the relevant area.

Impairment indicators can also be internal in nature. Evidence that an asset or CGU has been damaged or become obsolete is likely to be an impairment indicator; for example a refinery destroyed by fire is, in accounting terms, an impaired asset. Changes in development costs, such as a well requiring significant rework, or significantly increased decommissioning costs, may also be impairment indicators. Other common indicators 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 higher level.

4.5.3 Cash generating units

A CGU is the smallest group of assets that generates cash inflows largely independent of other assets or groups of assets [IAS 36 para 6]. A field and its supporting infrastructure assets in an upstream entity will often be identified as a CGU. 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.

Identifying the CGU (1)

What is the CGU in upstream oil and gas operations?

Background

Entity GBO has upstream operations in a number of locations around the world. The majority of operations are in production-sharing contracts for single fields or major projects. However it owns a number of properties in the Gulf of Mexico. The fields are supported by a shared loading platform and connected to a pipeline to the loading platform.

Management considers that the CGU for impairment testing purposes is a region or country. Is management's proposal appropriate?

Solution

No. Each field is generally capable of generating cash inflows largely independently from the other fields. It is unlikely that an outage on one field would require the shut-down of another field. However, where this would be the case then it would be appropriate to group such fields together.

The Gulf of Mexico fields might meet this criterion if all depend on the shared loading platform to generate future cash flows. Thus if all these fields would have to be shut-down if the shared loading platform was out of operation, then it could be argued that the fields it serves do not generate cash flows independently from each other. However, if alternative loading facilities are readily available, then each field should be treated as a separate cash generating unit and the shared loading platform should be treated as a common asset and allocated to each CGU.

Identifying the CGU (2)

What is the CGU in retail petroleum operations?

Background

The company owns retail petrol stations across Europe. It monitors profitability on a regional basis for larger countries such as Spain, Italy, France, Germany and the UK. Geographically smaller countries such as Greece, Austria, Switzerland and Portugal are monitored on a country basis. The costs of shared infrastructure for supply, logistics and regional management are grouped with the regions or countries that they support.

Station and regional managers are compensated based on performance of their station or stations, cash flow and profitability information is available at the level of the individual stations.

Management considers that the CGU for impairment testing purposes is a region or country. Is management's proposal appropriate?

Solution

No. The regions and countries are not CGUs. The lowest level at which largely separate cash flows are generated is at the level of an individual petrol station. Management assesses business

performance on a station-specific basis to compensate station managers and on a regional basis to assess return on investment incorporating shared infrastructure assets.

When impairment testing is required because of the presence of impairment indicators, petrol stations should be individually tested for impairment. The cash flows of the stations are then grouped for the purposes of assessing impairment of shared infrastructure assets.

4.5.4 Shared assets

Several fields located in the same region may share assets (for example, pipelines to transport gas or oil onshore, port facilities or processing plants). Judgement is involved in determining how such shared assets should be treated for impairment purposes. Factors to consider include:

- whether the shared assets generate substantial cash flows from third parties as well as the entity's own fields – if so, they may represent a separate CGU;
- how the operations are managed.

Any shared assets that do not belong to a single CGU but relate to more than one CGU still need to be considered for impairment purposes. There are two ways to do this and management should use the method most appropriate for the entity. Shared assets can be allocated to individual CGUs or the CGUs can be grouped together to test the shared assets.

Under the first approach, the assets should be allocated to each individual CGU or group of CGUs on a reasonable and consistent basis. The cash flows associated with the shared assets, such as fees from other users and expenditure, form part of the cash flows of the individual CGU.

The second approach has the group of CGUs that benefit from the shared assets grouped together to test the shared assets. The allocation of any impairment identified to individual CGUs should be possible for shared assets used in the processing or transportation of the output from several fields and, for example, could be allocated between the fields according to their respective reserves/resources.

4.5.5 Fair value less cost of disposal (FVLCOB)

Fair value less cost of disposal 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 FVLCOB 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.

FVLCOB is less restrictive in its application than VIU and can be easier to work with. It is more commonly used in practice, particularly for recently acquired assets. The underlying assumptions in a FVLCOB model are usually, but not always, closer to those that management have employed in their own forecasting process. The output of a FVLCOB calculation may feel intuitively more correct to management.

The assumptions and other inputs used in a DCF model for FVLCOB should incorporate observable market inputs as much as possible. The assumptions should be both realistic and consistent with what a typical market participant would assume. Assumptions relating to forecast capital expenditures that enhance the productive capacity of a CGU can therefore be included in the DCF model, but only to the extent that a typical market participant would take a consistent view. The amount calculated for FVLCOB is a post-tax recoverable amount. It is therefore compared against the carrying amount of the CGU on an after-tax basis; that is, after deducting deferred tax liabilities relating to the CGU/group of CGUs. This is particularly relevant in upstream businesses when testing

goodwill for impairment. A major driver of goodwill in upstream acquisitions is the calculation of deferred tax on the reserves and resources acquired. Marginal tax rates in the 80% to 90% region are not unheard of, thus the amount of goodwill can be substantial. The use of FVLCOB can alleviate the tension of substantial goodwill associated with depleting assets.

Post-tax cash flows are used when calculating FVLCOB using a discounted cash flow model. The discount rate applied in FVLCOB should be a post-tax market rate based on a market participant's weighted average cost of capital.

4.5.6 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 [IAS 36 para 6]. 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 include expenditure necessary to maintain the current performance of the asset [IAS 36 para 44]. The cash flows used in the VIU calculation are based on management's most recent approved financial budgets/ forecasts. The assumptions used to prepare the cash flows should be based on reasonable and supportable assumptions. Assessing whether the assumptions are reasonable and supportable is best achieved by benchmarking against market data or performance against previous budgets.

The discount rate used for VIU is pre-tax and applied to pre-tax cash flows [IAS 36 para 55]. This is often the most difficult element of the impairment test, as pre-tax rates are not available in the market place. Arriving at the correct pre-tax rate is a complex mathematical exercise. Computational short cuts are available if there is a significant amount of headroom in the VIU calculation. However, grossing up the post-tax rate seldom gives an accurate estimate of the pre-tax rate.

Period of projections

The cash flow projections used to determine VIU can include specific projections for a maximum period of five years, unless a longer period can be justified. A longer period will often be appropriate for oil and gas assets based on the proven and probable reserves and expected annual production levels. After the five-year period a VIU calculation should use assumptions consistent with those used in the final period of specific assumptions to arrive at a terminal value. Assumptions on the level of reserves expected to be produced should be consistent with the latest estimates by reserve engineers, annual production rates should be consistent with those for the preceding five years, and price and cost assumptions should be consistent with the final period of specific assumptions.

Commodity prices in VIU

Estimates of future commodity prices will need to be included in the cash flows prepared for the VIU calculation. Management usually take a longer-term approach to the commodity price; this is not always consistent with the VIU rules. Spot prices are used unless there is a forecast price available as at the impairment test date. In the oil and gas industry there are typically forward price curves available and in such circumstances these provide a reference point for forecast price assumptions. Those forecast prices should be used for the future periods covered by the VIU calculation. Where the forward price curve does not extend far enough into the future, the price at the end of the forward curve is generally held steady, unless there is a compelling reason to adjust it.

The future cash flows relating to the purchase or sale of commodities might be known from forward purchase or sales contracts. Use of these contracted prices in place of the spot price or forward curve price for the contracted quantities will generally be appropriate.

However, some forward purchase and sales contracts will be accounted for as derivative contracts at fair value in accordance with IAS 39 / IFRS 9 and are recognised as current assets or liabilities. They are therefore excluded from the IAS 36 impairment test. The cash flow projections used for the VIU calculation should exclude the pricing terms of the sales and purchase contracts accounted for in accordance with IAS 39 / IFRS 9.

Foreign currencies in VIU

Foreign currencies may be relevant to impairment testing for two reasons:

- a) when all the cash flows of a CGU are denominated in a single currency that is not the reporting entity's functional currency; and
- b) when the cash flows of the CGU are denominated in more than one currency.

a) CGU cash flows differ from entity's functional currency

All future cash flows of a CGU may be denominated in a single currency, but one that is different from the reporting entity's functional currency. The cash flows used to determine the recoverable amount are forecast in the foreign currency and discounted using a discount rate appropriate for that currency. The resulting recoverable amount is translated into the entity's functional currency at the spot exchange rate at the date of the impairment test [IAS 36.54].

b) CGU cash flows are denominated in more than one currency

Some of the forecast cash flows may arise in different currencies. For example, cash inflows may be denominated in a different currency from cash outflows. Impairment testing involving multiple-currency cash flows can be complex and may require consultation with specialists.

The currency cash flows for each year for which the forecasts are prepared should be translated into a single currency using an appropriate exchange rate for the time period. The spot rate may not be appropriate when there is a significant expected inflation differential between the currencies. The forecast net cash flows for each year are discounted using an appropriate discount rate for the currency to determine the net present value. If the net present value has been calculated in a currency different from the reporting entity's functional currency, it is translated into the entity's functional currency at the spot rate at the date of the impairment test [IAS 36.54].

The use of the spot rate, however, can generate an inconsistency, to the extent that future commodity prices denominated in a foreign currency reflect long-term price assumptions but these are translated into the functional currency using a spot rate. This is likely to have the greatest impact for operations in countries for which the strength of the local currency is significantly affected by commodity prices. Where this inconsistency has a pronounced effect, the use of FVLCOD may be necessary.

Assets under construction in VIU

The VIU cash flows for assets that are under construction and not yet complete should include the cash flows necessary for their completion and the associated additional cash inflows or reduced cash outflows. An oil or gas field that is part-developed is an example of a part-constructed asset. The VIU cash flows should therefore include the cash flows to complete the development to the extent that they are included in the original development plan and the associated cash inflows from the expected sale of the oil and gas.

4.5.7 Interaction of decommissioning provisions and impairment testing

Decommissioning provisions and the associated cash flows can be either included or excluded from the impairment test, provided the carrying amount of the asset and the cash flows are treated consistently. IAS 36 requires the carrying amount of a liability to be excluded from the carrying amount of a CGU unless the recoverable amount of the CGU cannot be determined without consideration of that liability [IAS 36 paras 76, 78]. This typically applies when the asset/CGU cannot be separated from the associated liability.

Decommissioning obligations are closely linked to the asset that needs to be decommissioned, although the cash flows associated with the asset may be independent of the cash flows of the decommissioning liability.

The VIU cash flow model uses a discount rate that is specific to the assets being tested, reflects time value of money and the return investors would require to invest in the asset. The performance of the asset will have a number of uncertainties associated with it; demand, price and operational risk among others. The cash outflows associated with a decommissioning obligation have different uncertainties associated with them, but these are more around amount and timing rather than occurrence or performance risk. Future sales might be uncertain but the need to restore at the end of the asset's life is not. These cash outflows should be discounted using the risk free rate required by IAS 37.

There is no guidance in the impairment standard on using FVLCOD as the recoverable amount for a CGU with a non-separable liability.

- One approach could be to produce a single cash flow model that provides a fair value of a CGU that includes the cash outflows for the decommissioning obligation. This approach is consistent with how a market participant would think about determining the fair value of the business. Timing of the decommissioning should be considered. Cash outflows for the decommissioning that will commence many years in the future would be incorporated in the later period in the cash flow model and have less impact on the recoverable amount determined. As a field approaches the end of its life and cash outflows are expected to begin within the next few years, these cash outflows would have more impact on the recoverable amount.
- An alternative approach would be to calculate the fair value of the asset excluding the cash outflows to satisfy the decommissioning obligation. The liability would be calculated separately using market participant assumptions rather than the IAS 37 approach. The liability measurement should reflect the amount the entity would need to pay to a third party to assume the obligation. This is likely to produce a higher value for the liability than under IAS 37. The amount determined for the liability would then be deducted from the amount determined for the asset to produce a 'net' fair value. This second approach is likely to be appropriate when the end of the life of the field is within the foreseeable future, less than five years or so.

The recoverable amount under FVLCOD is then compared to the carrying amount of the CGU including the decommissioning obligation measured under IAS 37.

Interaction of decommissioning provision and impairment testing

How is a decommissioning provision included in an impairment test?

Background

Entity A incurs expenditure of C100 constructing an oil production platform. The present value of the decommissioning obligation at the date on which the platform is put into service is C25. The present value of the future cash inflows from expected production is C180. The present value of the future cash outflows from operating the platform is C50, and the present value of the future cash outflows from performing the decommissioning of the platform is C25.

Solution

The following example illustrates the results of both the inclusion and exclusion of the decommissioning liability in the carrying amount of the CGU and the cash flow projections.

The net present value of future cash flows associated with operating the field is as follows:

| VIU calculation | Including | Excluding |
|---|------------------|------------------|
| Cash inflows from sale of oil produced | 180 | 180 |
| Operating cash outflows | (50) | (50) |
| Cash outflows from decommissioning at end of field life | (25) | – |
| Net present value of cash flows (recoverable amount) | 105 | 130 |
| Carrying amount of PPE (including cost of future decommissioning) | 125 | 125 |
| Carrying amount of decommissioning provision | (25) | – |
| Net carrying amount of CGU | 100 | 125 |

Determination of carrying amount

The recoverable amount in both cases exceeds the carrying amount of the assets and hence, no impairment charge is required. However, if the discount rate used for arriving at the cash outflows from decommissioning is different from that used for the carrying amount of decommissioning provision, a difference in their values could arise.

4.5.8 Goodwill impairment testing

IAS 36 requires goodwill to be tested for impairment at least annually and tested at the lowest level at which management monitors it. The lowest level cannot be higher than the operating segment to which goodwill belongs under IFRS 8 *Operating segments*.

The grouping of CGUs for impairment testing should reflect the lowest level at which management monitors the goodwill. If that is on an individual CGU basis, testing goodwill for impairment should be performed on that individual basis. However, when management monitors goodwill based on a group of CGUs, the impairment testing of the goodwill should reflect this.

Goodwill is tested for impairment annually and when there are impairment indicators. Those indicators might be specific to an individual CGU or group of CGUs.

IAS 36 requires a bottom up then top down approach for impairment testing, and the order in which the testing is performed is crucial. The correct approach is particularly important if there is goodwill, indefinite lived assets, shared assets or corporate assets. First, any individual CGUs with indicators of impairment must be tested and the impairment loss recorded in the individual CGU. Then CGUs can be grouped for the purposes of testing shared assets, indefinite lived intangibles, goodwill and corporate assets. The amended carrying values of any individual CGUs that have been adjusted for an impairment charge are used as part of the second stage of the impairment test.

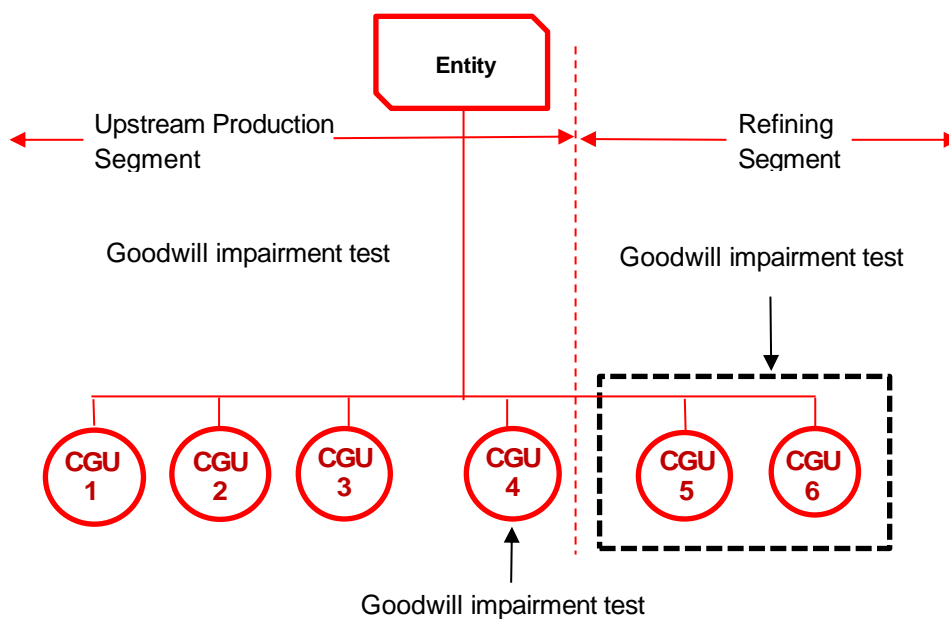
If the impairment test shows that the recoverable amount of the group of CGUs exceeds the carrying amount of that group of CGUs (including goodwill), there is no impairment to recognise. However, if the recoverable amount is less than the combined carrying value, the group of CGUs and the goodwill allocated to it is impaired. The impairment charge is allocated first to the goodwill balance to reduce it to zero, and then pro rata to the carrying amount of the other assets within the group of CGUs.

Goodwill is also tested for impairment when there is an indicator that it is impaired, or when there is an indicator that the CGU(s) to which it is allocated is impaired. When the impairment indicator relates to specific CGUs, those CGUs are tested for impairment separately before testing the group of CGUs and the goodwill together.

Impairment testing of goodwill

At what level is goodwill tested for impairment?

The diagram below illustrates the levels at which impairment testing may be required. The entity has two operating segments, Upstream Production and Refining. The Upstream Production segment comprises four producing fields which each represent CGUs; the Refining segment comprises two refineries which represent separate CGUs. There is goodwill allocated to each CGU. The goodwill within the Upstream Production segment is monitored in two parts. The goodwill allocated to CGUs 1, 2 and 3 is monitored on a collective basis; the goodwill allocated to CGU 4 is monitored separately. The goodwill within the Refining segment is monitored at the Refining level – that is, goodwill allocated to CGUs 5 and 6 is monitored on a combined basis.



If there is an impairment indicator for CGU 2, the CGU is tested for impairment separately, excluding the goodwill allocated to it. Any impairment loss calculated in this impairment test is allocated against the assets within the CGU. This allocation of the impairment charge is made on a pro rata basis to the carrying value of the assets within the CGU. The testing of CGU 2 at this level excludes goodwill, so no impairment is allocated against goodwill in this part of the impairment test.

After recording any impairment arising from testing CGU 2 for impairment, CGUs 1, 2 and 3 and the goodwill allocated to them is then tested for impairment on a combined basis. Any impairment loss calculated in this impairment test is allocated first to the goodwill. If the impairment charge in this test exceeds the value of goodwill allocated to CGUs 1, 2 and 3, the remaining impairment charge is allocated against the fixed and intangible assets of CGUs 1, 2 and 3 pro rata to the carrying value of the assets within those CGUs.

A similar approach is taken for CGU 4. However, because no other CGU is combined with CGU 4 for goodwill impairment testing, there is no need to test CGU 4 for impairment separately from the goodwill allocated to it.

4.5.9 Impairment reversals

The actual results in subsequent periods should be compared with the cash flow projections (used in impairment testing) made in the previous year. Where performance has been significantly better than previously estimated, this is an indicator of potential impairment reversal. Impairment charges are reversed (other than against goodwill) where the increase in the recoverable amount arises from a change in the estimates used to measure the impairment. Estimates of variables, such as commodity prices, reflect the expectations of those variables over the period of the forecast cash flows, rather than changes in current spot prices. The use of medium to long-term prices for commodities means that impairment charges and reversals tend not to reflect the same volatility as current spot prices. Impairment reversals should only be recognised where there has been a clear increase in the service potential of a CGU and not simply due to headroom created by the passage of time; for instance, the unwind in discount rates, further DD&A charges or other similar items.

4.6 Royalties and income taxes

Petroleum taxes generally fall into two main categories – those that are calculated on profits earned (income taxes) and those calculated on 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. In some countries the authorities may also charge ‘production taxes’: charges which are based on a specified tax rate per quantity of oil or gas extracted regardless of whether that oil or gas is subsequently sold. Such taxes may be recognised as operating expenses.

4.6.1 Petroleum taxes – royalty and excise

Petroleum taxes that are calculated by applying a tax rate to volume or a measure of revenue which has not been adjusted for expenditure do not fall within the scope of IAS 12 *Income taxes* and are not income taxes. Determining whether a petroleum tax represents an income tax can require judgement.

Petroleum taxes outside the scope of IAS 12 do not form part of revenue or give rise to deferred tax liabilities. Revenue-based and volume-based taxes are recognised when the revenue is recognised [IAS 18 para 8]. 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. No deferred tax is calculated. The smoothing of the estimated total tax charge over the life of a field is not appropriate [IAS 37 paras 15, 36].

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.

4.6.2 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 [IAS 12 para 5]. The profit measure used to calculate the tax is that required by the 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 Petroleum Resource Rent Tax.

Classification as income tax or royalty

Does Petroleum Revenue Tax (PRT) in Utopia fall within the scope of IAS 12?

Background

Entity A has an interest in an oil field in Utopia. The field is subject to PRT levied by the government of Utopia.

The determination of the amount of PRT payable by an entity is set out in the tax legislation created by the Utopian government. The PRT payable by an entity is calculated based on the profits earned from the production of oil.

The profits against which PRT is calculated are determined by legislation. The PRT taxable profit is calculated as the revenue earned from the sale of oil, on an accruals basis, less the costs incurred to produce and deliver the oil to its point of sale.

The deductible costs permitted by the legislation include all direct costs of production and delivery. Capital-type costs are allowable as incurred – there is no spreading/amortisation of capital costs as occurs in financial reporting or corporation tax calculations.

The non-deductible costs are financing costs, freehold property costs and certain other types of costs. However, an additional allowance ('uplift') against income is permitted in place of interest costs. The uplift deduction is calculated as 35% of qualifying capital expenditure.

Solution

PRT falls within the scope of IAS 12. PRT is calculated by applying the PRT tax rate to a measure of profit that is calculated in accordance with the PRT tax legislation.

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 [IAS 12 paras 15, 24]. 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 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 (e.g. 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 [IAS 12 paras 47, 51].

Should deferred tax be recognised on super deductions receivable on income tax?

Background

Entity A has an interest in an oil field and the field is subject to Petroleum Revenue Tax (PRT) levied by the government of Utopia. Entity A receives 'uplift' in respect of the cost of the qualifying capital expenditures for PRT purposes. Uplift provides entity A with an additional deduction against profits chargeable to PRT of 35% of qualifying capital expenditures. Entity A is able to recognise a deduction of 100% of the costs of qualifying capital expenditure in calculating profits subject to PRT when the tax authorities agree the deductibility.

A further 35% deduction is allowed when the tax authorities agree that the specific expenditure qualifies for uplift. The test for deductibility for the 35% uplift is more restrictive than the test for the base 100% deduction. The deductions are made in full against the calculation of profits subject to PRT in the period in which the respective agreements are received from the tax authorities. The cumulative amount of depreciation charged for financial reporting purposes under IFRS remains at 100% over the life of the asset, i.e. the regulations allow for a higher deduction to be charged than the depreciation charge over the life of the asset.

The following is an illustration of how super deduction works.

Say the company has developed four assets A, B, C and D having a capital cost of 1000, 1500, 2000 and 2500 GBP respectively. All these assets are qualifying capital expenditures and assets A and C qualify for an additional deduction (uplift) of 35%. In such case the following will be the amounts deductible:

| Asset allowed | Capital cost (GBP) | Amount of deduction | Uplift |
|---------------|--------------------|---------------------|--------------|
| A | 1,000 | 1,350 = 1,000 + 350 | 35% of 1,000 |
| B | 1,500 | 1,500 | Not eligible |
| C | 2,000 | 2,700 = 2,000 + 700 | 35% of 2,000 |
| D | 2,500 | 2,500 | Not eligible |

Deduction for uplift is allowed in the year in which the tax authorities agree that the specific expenditure qualifies for uplift, which may be different from the year in which the capital expenditure is incurred or the year in which the 100% deduction is claimed.

At what value should A's management recognise deferred PRT in respect of the capital assets?

Solution

The portion of the PRT tax base relating to the uplift arises on initial recognition of the asset. As per paragraph 24 of IAS 12, a deferred tax asset shall be recognised for all deductible temporary differences to the extent that it is probable that taxable profit will be available against which the deductible temporary difference can be utilised, unless the deferred tax asset arises from the initial recognition of an asset or liability in a transaction that:

- is not a business combination; and
- at the time of the transaction, affects neither accounting profit nor taxable profit (tax loss).

From the above, it can be seen that the deferred PRT would be covered under the IRE, and deferred taxes on the same would not be recognised. The availability of the super deduction would

have been factored into any final price agreed between the seller and buyer for the transaction. Accordingly, the cost of the acquisition to the purchaser would represent its full value and no additional uplift should be made to this in respect of the super deduction. US GAAP allows a gross up of the asset and a related deferred tax liability in respect of such a super deduction; however, this is not permitted under IAS 12.

4.6.3 Taxes 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.

4.6.4 Deferred tax and acquisitions of participating interests in jointly controlled assets

The deferred tax consequences of the acquisition of a participating interest in a jointly controlled asset are discussed in section 4.1.9.

4.6.5 Discounting of petroleum taxes

Tax liabilities are measured at the amount expected to be paid to the taxation authorities and accordingly would not be discounted. Accordingly, petroleum taxes which fall within the scope of IAS 12 would not be discounted. Petroleum taxes outside the scope of IAS 12 can be measured after considering the effects of discounting.

4.6.6 Royalties to non-governmental bodies and retained interests

Petroleum 'taxes' do not always relate to dealings with government authorities. Sometimes arrangements with third parties are such that they result in the payment of a royalty. For example, one party may own the licence to a field which is used by an operating party on the terms that, once the operator starts producing, it must pay the licence holder a percentage of its profits or a percentage of production.

In cases where the licence holder receives a fixed payment per unit extracted or sold, it would generally be in the nature of royalty. However, if the licence holder is entitled to a portion of the oil or gas extracted, it could potentially mean that the licence holder retains an interest in the field.

It would be important to consider whether the license holder has a claim on the profits of the entity or on its net assets. If the license holder retains an interest in the net assets of the entity, it would have to be accounted for under the relevant IFRS.

4.7 Functional currency

4.7.1 Overview

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.

4.7.2 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. Management should focus on the primary economic environment in which the entity operates when determining the functional currency. The denomination of selling prices is important but not determinative. 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. Although entities may buy and sell in dollar denomination, they are not exposed to the US economy unless they are exporting to the US or another economy closely tied to the US.

Dollar denomination is a pricing convention rather than an economic driver. Instead, the main influence on the entity is demand for the products and ability to produce the products at a competitive margin, which will be dependent on the local economic and regulatory environment. Accordingly, it is relatively common for oil and gas entities to have a functional currency which is their local currency rather than the US dollar, even where their sales prices are in dollars.

Functional currency is determined on an entity-by-entity basis for a multi-national group. It is not unusual for a multi-national oil and gas company to have many different functional currencies within the group.

There are primary indicators of functional currency: the currency of sales prices, the currency of the country that will consume and regulate the products, and the currency of the cost of labour.

It is difficult to identify a single country whose competitive forces and regulations mainly determine selling prices in oil and gas. If the primary indicators do not provide an obvious answer to the functional currency question, 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.

How to determine the functional currency of an entity with products normally traded in a non-local currency (1)

What is the functional currency of an entity which is based in Saudi Arabia but prices all products sold in US dollars?

Background

Entity A operates an oil refinery in Saudi Arabia. All of the entity's income is denominated and settled in US dollars. Refined product is primarily exported by tanker to the US. The oil price is subject to worldwide supply and demand, and crude oil is routinely traded in US dollars around

the world. Around 55% of entity A's cash costs are imports or expatriate salaries denominated in US dollars. The remaining 45% of cash expenses are incurred in Saudi Arabia and denominated and settled in riyal. The non-cash costs (depreciation) are US dollar denominated, as the initial investment was in US dollars.

Solution

The factors point toward the functional currency of entity A being the US dollar. The product is primarily exported to the US. The revenue analysis points to the US dollar. The cost analysis is mixed. Depreciation (or any other non-cash expenses) is not considered, as the primary economic environment is where the entity generates and expends cash. Operating cash expenses are influenced by the riyal (45%) and the US dollar (55%). Management is able to determine the functional currency as the US dollar, as the revenue is clearly influenced by the US dollar and expenses are mixed.

How to determine the functional currency of an entity with products normally traded in a non-local currency (2)

What is the functional currency of an entity which is based in Russia but prices all products sold in US dollars?

Background

Entity A operates a producing field and an oil refinery in Russia and uses its product to supply independent petrol stations in Moscow. All of the entity's income is denominated in US dollars but is settled in a mixture of dollars and local currency. Around 45% of entity A's cash costs are expatriate salaries denominated in US dollars. The remaining 55% of cash expenses are incurred and settled in roubles.

Solution

The factors point toward the functional currency of entity A being the Russian Rouble. Although selling prices are determined in dollars, the demand for the product is clearly dependent on the local economic environment in Russia. Although the cost analysis is mixed based on the level of reliance on the Moscow marketplace for revenue and margin management is able to determine the functional currency as the Russian rouble.

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 often used as the basis for determining the functional currency.

4.7.3 Change in functional currency

Once the functional currency of an entity is determined, it should be used consistently, unless significant changes in economic facts, events and conditions indicate that the functional currency has changed.

Oil and gas entities at different stages of operation may reach a different view about their functional currency. A company which is in the exploration phase may have all of its funding in US dollars and

be reliant on its parent company. It may also incur the majority of its exploration costs in US dollars (the availability of drilling rigs may require these to be sourced from the US). At this stage it may conclude US dollars as being the functional currency.

However, when it reaches the development phase, its transactions may be predominantly denominated in local currency as it is more reliant on the local workforce and suppliers to perform the development activity. The functional currency may then change to being the local currency.

The functional currency may then change again when the project reaches the production phase and revenue is generated in US dollars. As explained above, a selling price in dollars would not automatically mean that the functional currency is US dollars and factors such as the territory the company sells to and marketplace in which it operates would have to be considered. This does, however, illustrate that determination of the functional currency can be an ongoing process and conclusions may change depending on the current facts and circumstances.

4.8 Leasing

In January 2016 the IASB issued IFRS 16 *Leases*. The new standard is effective on 1 January 2019. The new standard is discussed in section 7.3. This section deals with the current requirements of IAS 17 *Leases*.

4.8.1 Overview

IAS 17 excludes application to leases to explore for or use oil, natural gas and similar non-regenerative resources. The exemption includes exploration and prospecting licences. IAS 17 is, however, applicable to other arrangements that are in substance a lease, and this would include the plant and machinery used to perform the exploration activity.

Many oil and gas entities enter into other arrangements that convey a right to use specific assets and these may need to be classified as leases. Examples of such arrangements include:

- service agreements;
- throughput arrangements;
- tolling contracts;
- energy-related contracts; and
- transportation service contracts.

4.8.2 When does a lease exist?

IFRIC 4 *Determining whether an arrangement contains a lease* establishes criteria for determining whether a contract should be accounted for as a lease.

The following conditions must be met for an arrangement to be considered a lease:

- fulfilment of the arrangement is dependent on the use of a specific asset; and
- the arrangement conveys the right to use the asset.

Use of a specific asset

A specific asset is identified either explicitly or implicitly in an arrangement. A specific asset is implicitly identified when:

- it is not economically feasible or practical for the supplier to use alternative assets;

- the supplier only owns one suitable asset for the performance of the obligation;
- the asset used needs to be at a particular location or is specialised; or
- the supplier is a special purpose entity formed for a limited purpose.

An arrangement that involves the use of assets located at or near an oil or gas field, where the geographical isolation precludes any practical form of substitution of the assets, would often meet this test.

Right to use the specific asset

Payment provisions under an arrangement should be analysed to determine whether the payments are made for the right to use the asset, rather than for the actual use of the asset or its output. This requires a consideration of whether any of these conditions are met:

- the purchaser has the ability (or right) to operate or direct others to operate the asset in a manner it determines while obtaining (or controlling) more than an insignificant amount of the output of the asset;
- the purchaser has the ability (or right) to control physical access to the asset while obtaining (or controlling) more than an insignificant amount of the output of the asset; and
- the purchase price is not a fixed/market price per unit of output, and it is remote that any third party will take more than an insignificant amount of the output of the asset.

Arrangements in which an oil and gas entity takes substantially all of the output from a dedicated asset will often meet one of the above conditions, resulting in treatment as a lease. This occurs sometimes in the oil and gas industry because of the remote location of fields.

Reassessment of whether an arrangement contains a lease

The reassessment of whether an arrangement contains a lease after inception is required if any of the following conditions are met:

- a change is made to the contractual terms, other than renewals and extensions;
- a renewal option is exercised or an extension is agreed that had not been included in the initial arrangement;
- a change is determined in relation to the assessment of whether fulfilment is dependent on a specified asset; or
- there is a substantial change to the asset.

The above conditions require arrangements to be continued to be assessed for treatment as a lease; however, a change in the determination of whether other parties obtain more than an insignificant amount from an asset is not a reassessment trigger.

For example, where a third party previously identified as obtaining more than an insignificant amount of an assets output shuts production, the entity continuing to operate is not required to reassess the arrangement under IFRIC 4.

4.8.3 Accounting for a lease

When an arrangement is within the scope of IFRIC 4, cash flows under the arrangement must be separated into their respective components. The components frequently include the right to use the asset, service agreements, maintenance agreements, and fuel supply. The payments for the right to use the asset are accounted for as a lease in accordance with the guidance in IAS 17. This includes the classification of the right of use as either an operating lease or a finance lease. The accounting for the other components is in accordance with the relevant guidance in IFRS.

Operating lease

If an arrangement contains an operating lease, the specific asset leased remains on the balance sheet of the lessor. Operating lease payments are recognised by the lessee on a straight line basis over the life of the lease.

Finance lease

If an arrangement contains a finance lease, the specific asset leased is recorded on the balance sheet of the lessee and not the lessor. The lessor recognises a lease receivable which falls within the scope of IAS 39's derecognition and impairment provisions.

The impact of this accounting treatment to the lessee is a gross up on the Statement of Financial Position of both assets and liabilities, whilst earnings will be impacted by the depreciation of the leased asset as well as an imputed interest charge. As a result of the finance lease accounting treatment, the earnings profile and key financial ratios may be materially impacted.

4.8.4 Presentation and disclosure

IAS 17 contains detailed disclosure requirements for leases. Common disclosures required include:

- a general description of an entity's significant lease arrangements;
- the total of future minimum lease payments and the present value for each of the following periods:
 - no later than one year;
 - later than one year and not later than five years; and
 - later than five years; and
- the carrying amount of assets held under finance leases.

4.9 Operating segments

4.9.1 Overview

Oil and gas companies often operate in a range of geographic locations and, in many cases, produce a diverse range of commodities from numerous fields. The core principle of segment reporting is to provide information to the users of financial statements to enable them to evaluate the nature, economic environments and financial effects of the business activities in which a company operates. Entities are often managed on a geographic or even product group basis. Financial reporting requirements for segment reporting are covered in IFRS 8.

Certain entities that do not have public debt or equity and are not in the process of registering any public securities may choose not to present segmented information.

4.9.2 What is an operating segment?

An operating segment is defined as a component of an entity:

- that engages in business activities from which it may earn revenues and incur expenses;
- for which discreet financial information is available; and
- whose operating results are regularly reviewed by the chief operating decision maker (CODM) of the entity to make decisions about resources to be allocated to the segment and assess a segment's performance.

A development project or exploration project will not necessarily earn revenues but it might still constitute an operating segment.

4.9.3 Identifying operating segments: ‘The management approach’

The concept of defining segments at the level of review of the CODM is commonly referred to as the ‘management approach’. The key benefits of this approach are that detailed segment information can be reported more frequently at a low incremental cost to prepare that allows a user to better understand an entity as they are able to see an entity through the eyes of management.

Identification of operating segments typically involves a four-step process:

1. Identify the CODM
2. Identify the business activities (these could be different fields or wider geographic regions as well as development/exploration or Corporate head office)
3. Determine whether discrete information is available for the business activities
4. Determine whether that information is reviewed by the CODM

The CODM defines a function and not necessarily a position or title – examples of the CODM include the Chief Executive Officer, the Chief Operating Officer and a group of executives or directors functioning in the CODM capacity.

4.9.4 Aggregation of operating segments

Two or more operating segments may be aggregated into a single operating segment for reporting purposes if the segments have similar economic characteristics and the segments are similar in each of the following respects:

- a) the nature of the products and services;
- b) the nature of the production processes;
- c) the type or class of customer for their products and services;
- d) the methods used to distribute their products or provide their services; and
- e) if applicable, the nature of the regulatory environment.

The ability of an entity to aggregate its segments based on the ‘similar economic characteristics’ criteria requires judgement to be applied to each set of facts and circumstances.

Aggregation of operating segments (1)

Background

An entity has three conventional gas fields in one region using the same pipeline. Production processes and cash costs are similar and marketing of the product is performed centrally (and sold based on the LME price). The CODM reviews information for the individual fields.

Each of the three fields is an operating segment. Can they be aggregated into a single reportable segment?

Solution

Yes, the aggregation criteria are met due to the similarity of economic characteristics (products, processes and financial and operating risks).

Aggregation of operating segments (2)

Background

An entity has two fields in the same region. One is a conventional field and the other is a field requiring hydraulic fracturing. The operating costs are quite different for each field. One field produces oil and the other produces a combination of oil and gas. The CODM reviews information for each of the fields and investors are provided with reserves and operational information for each field.

Each of the fields is an operating segment. Can the two fields be aggregated into a single reportable segment?

Solution

It is unlikely that the fields would be aggregated due to the differences in products and processes. They do not have similar economic characteristics and would be two reportable segments.

The aggregation of such segments is for presentation purposes only, it does not affect the level at which goodwill is tested for impairment (i.e. the maximum level that goodwill can ever be tested at is the level of an operating segment prior to aggregation).

4.9.5 Minimum reportable segments

After identifying operating segments and aggregating those that met the aggregation criteria, an entity should determine which operating segments or aggregations of operating segments meet the quantitative thresholds for separate disclosure as reportable segments. An entity must report information separately if any of the following quantitative thresholds is met:

- a) Reported revenues, including sales to external customers and intersegment sales/transfers are 10% or more of the combined internal and external revenue of all operating segments.
- b) The absolute amount of the reported profit or loss is 10% or more of the greater, in absolute amounts, of the combined reported profit of all operating segments that did not report a loss and the combined reported loss of all reporting segments that reported a loss.
- c) Its assets are 10% or more of the combined assets of all operating segment.

Identifying reportable segments

Background

A company has the following operating segments. The revenues (internal and external), profits and assets are set out below.

| Segments | Total revenue | | Profit / (loss) | | Total assets | |
|----------|-------------------|-----|------------------|-----|-------------------|-----|
| A | 11,000,000 | 36% | 2,000,000 | 50% | 25,000,000 | 37% |
| B | 7,500,000 | 25% | 1,000,000 | 25% | 15,500,000 | 23% |
| C | 3,000,000 | 10% | (1,000,000) | 25% | 10,500,000 | 15% |
| D | 3,500,000 | 11% | (500,000) | 13% | 7,000,000 | 10% |
| E | 4,000,000 | 13% | 600,000 | 15% | 7,000,000 | 10% |
| F | 1,500,000 | 5% | 400,000 | 10% | 3,500,000 | 5% |
| | <u>30,500,000</u> | | <u>2,500,000</u> | | <u>68,500,000</u> | |

How many reportable segments does entity A have?

Solution

Segments A, B, D and E clearly satisfy the revenue and assets test (so there is no need to consider the profits test in these cases) and are reportable segments.

Segment C does not satisfy the revenue test but does satisfy the asset test and the profits test and is also a reportable segment.

Segment F does not satisfy the revenue or the assets test but does satisfy the profits test.

Therefore all six segments represent reportable segments and should not be aggregated.

If the total external revenue reported by reportable segments is less than 75% of the entity's revenue, additional operating segments will need to be identified as reportable segments until at least 75% of the entity's revenue is included in reportable segments.

4.9.6 Disclosure

Entities are required to disclose information consistent with the core principles of segment reporting. The disclosure requirements are summarised in the table below.

| Reference to disclosure requirements | Required disclosures |
|---|--|
| General information | <ul style="list-style-type: none"> • Factors used to identify the reportable segments. • Types of product/service from which each reportable segment derives its revenue. |
| Information about the reportable segment: profit or loss, revenue, expenses, assets, liabilities and the basis of measurement | <p>For each reportable segment an entity should disclose:</p> <ul style="list-style-type: none"> • A measure of profit or loss. • A measure of total assets or liabilities if this is regularly provided to the CODM. • A number of specific disclosures, such as revenues from external customers if they are included in segment profit or loss and presented regularly to the CODM. • Explanation of the measurement of the segment disclosures. • The basis of accounting for transactions between reportable segments. • The nature of differences between the measurements of segment disclosures and comparable items in the entity's financial report. |
| Reconciliation | Totals of segment revenue, segment profit or loss, segment assets and segment liabilities and any other material segment items to corresponding totals within the financial statements. |
| Entity-wide disclosures (required even if only one segment reported) | <ul style="list-style-type: none"> • Revenues from external customers for each product and service, or each group of similar products and services. • Revenues from external customers attributed to the entity's country of domicile and attributed to all foreign countries from which the entity derives revenues. • Revenues from external customers attributed to an individual foreign country, if material. • Non-current assets (other than financial instruments, deferred tax assets, post-employment benefit assets, and rights arising under insurance contracts) located in the entity's country of domicile and in all foreign countries in which the entity holds assets. • Non-current assets in an individual foreign country, if material. • Extent of reliance on major customers, including details if any customer's revenue is greater than 10% of the entity's revenue. |

4.10 Consolidation

This section focuses on the requirements of IFRS 10 and the definition and guidance with regard to 'control'.

4.10.1 Control

IFRS 10 confirms consolidation is required where control exists. The standard redefines control: where an investor has the power and exposure to variable returns and the ability to use that power it controls the investee.

Factors to be assessed by oil and gas entities to determine control include:

- the purpose and design of an investee;
- whether rights are substantive or protective in nature;
- existing and potential voting rights;
- whether the investor is a principal or agent; and
- relationships between investors and how they affect control.

Only substantive rights are considered in the assessment of power – protective rights, designed only to protect an investor's interest without giving power over the entity and which may only be exercised under certain conditions, are not relevant in the determination of control.

Potential voting rights are "rights to obtain voting rights of an investee, such as those within an option or convertible instrument." Potential voting rights with substance should be considered when determining control. This is a change from the previous standard where all and only presently exercisable rights were considered in the determination of control.

The 'principal versus agent' determination is also important. Parties in oil and gas arrangements will often be appointed to operate the project on behalf of the investors. A principal may delegate some of its decision authority to the agent, but the agent would not be viewed as having control when it exercises such powers on behalf of the principal.

Economic dependence in an arrangement, such as a refinery which relies on crude oil to be provided by a specific supplier, is not uncommon, but is not a priority indicator. If the supplier has no influence over management or decision-making processes, dependence would be insufficient to constitute power.

5. Financial instruments, including embedded derivatives

IFRS 9 has been finalised and is mandatorily applicable (with some minor exemptions) from 2018. Early adoption is available. This guidance is based on the current requirements of IAS 39 and does not address any changes that may be necessary once IFRS 9 is applicable. The requirements of IFRS 9 are discussed in section 7.1.

5.1 Overview

The accounting for financial instruments can have a major impact on an oil and gas entity's financial statements. Some entities have specific energy trading activities and those are discussed in section 5.7. Many entities 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 the interaction with the revenue and leasing standards and from 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.

5.1.1 Scope of IAS 39

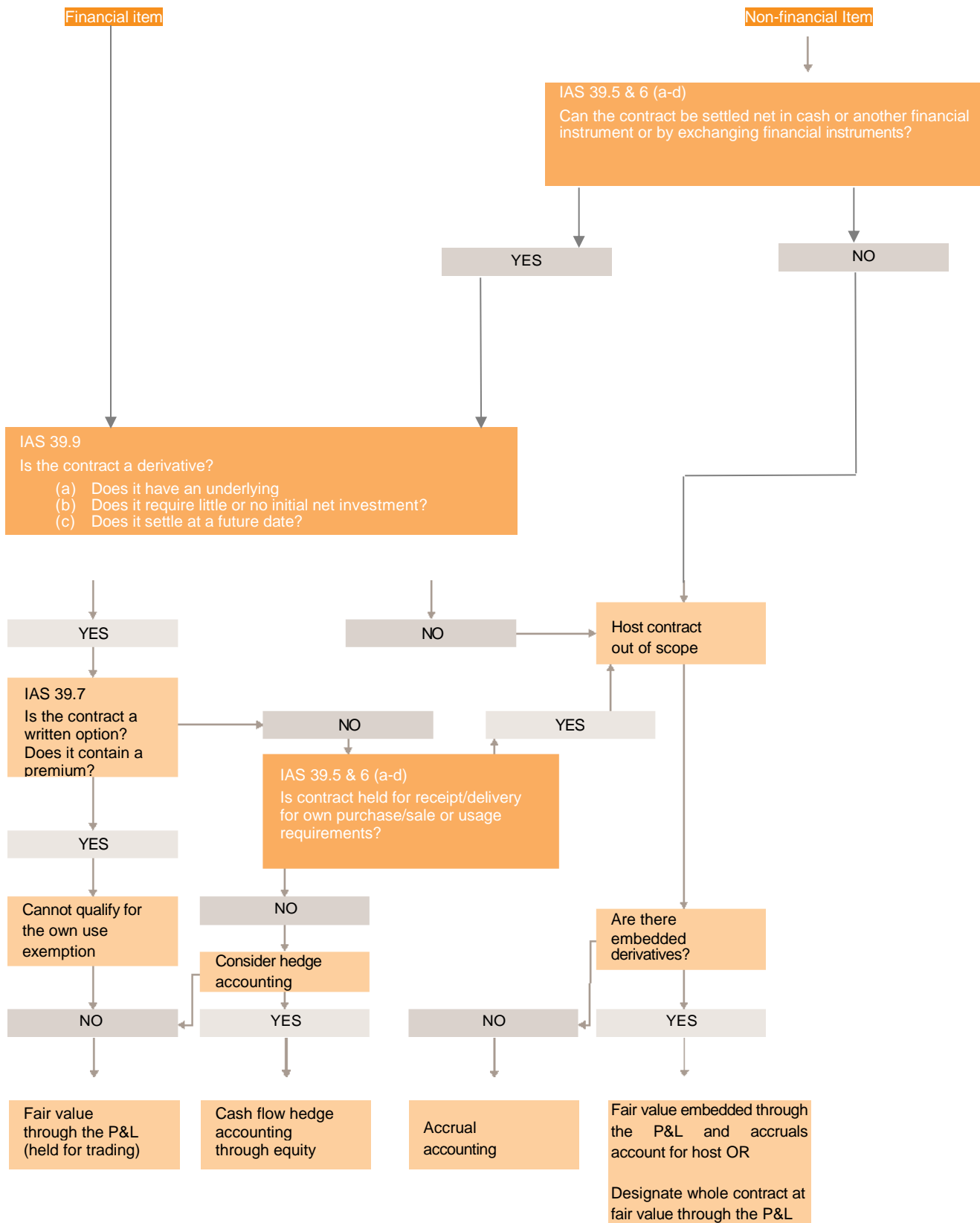
Contracts to buy or sell a non-financial item, such as a commodity, that can be settled net in cash or another financial instrument, or by exchanging financial instruments, are within the scope of IAS 39. They are accounted for as derivatives and are marked to market through the income statement. Contracts 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. Some practical considerations for the own use assessment are included in section 5.7.

The 'net settlement' notion in IAS 39.6 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; or
- (d) the commodity that is the subject of the contract is readily convertible to cash [IAS 39.6].

The process for determining the accounting for a commodity contract can be summarised in the following decision tree:

Commodity contract decision tree (IAS 39)



5.1.2 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 (in cash or by exchanging another financial instrument) can prevent an entire category of contracts from qualifying for the 'own use' treatment (i.e. all similar contracts must then be recognised as derivatives at fair value). A level of judgement will be required in this area as net settlements caused by unique events beyond management's control may not necessarily prevent the entity from applying the 'own use' exemption to all similar contracts. This should be assessed on a case by case situation. Judgement will also be required on what constitutes 'similar' in the context of the 'own use' assessment – contracts with 'similar' legal terms may be 'dissimilar' if they are clearly segregated from each other from inception via book structure.

A contract that falls into IAS 39.6(b) or (c) 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) are evaluated to see if they qualify for 'own use' treatment.

Many contracts for commodities such as oil and gas meet the criterion in IAS 39.6(d) (i.e. 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 critical in determining the appropriate treatment of its commodity contracts. It is important to match the own use contracts with the physical needs for a commodity by the entity. A well-managed process both around forecasting these physical levels and matching them to contracts is very important.

'Own use' contracts

Background

Entity A, the buyer, is engaged in power generation and entity B, the seller, produces natural gas. Entity A has entered into a ten year contract with entity B for purchase of natural gas.

Entity A extends an advance of USD 1 billion to Entity B which is the equivalent of the total quantity contracted for ten years at the rate of USD 4.5 per MMBtu (forecasted price of natural gas). This advance carries interest of 10% per annum which is settled by way of supply of gas.

As per the agreement, predetermined/fixed quantities of natural gas have to be supplied each month. There is a price adjustment mechanism in the contract such that upon each delivery the difference between the forecasted price of gas and the prevailing market price is settled in cash.

If entity B falls short of production and does not deliver gas as agreed, entity A has the right to claim penalty by which entity B compensates entity A at the current market price of gas.

Is this contract an 'own use' contract?

Solution

The 'own use' criteria are met. There is an embedded derivative (being the price adjustment mechanism) but it does not require separation. See further the discussion of embedded derivatives at section 5.4.

The contract seems to be net settled because the penalty mechanism requires entity B to compensate entity A at the current prevailing market price. This will meet the condition in IAS 39.6(a). The expected frequency/ intention to pay a penalty rather than deliver does not matter as the conclusion is driven by the presence of the contractual provision. Further, if natural gas is readily convertible into cash in the location where the delivery takes place, the contract will be considered net settled.

However, the contract will still qualify as 'own use' as long as it has been entered into and continues to be held for the expected counterparties' sales/usage requirements. However, if there is volume flexibility then the contract is to be regarded as a written option. A written option is not entered into for 'own use'.

Therefore, although the contract may be considered net settled (depending on how the penalty mechanism works and whether natural gas is readily convertible into cash in the respective location), it can still claim an 'own use' exemption provided the contract is entered into and is continued to held for the parties' own usage requirements.

'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.

A written option to buy or sell a non-financial item that can be settled net cannot be considered to be entered into 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. This is because an option written by the entity is outside its control as to whether the holder will exercise it or not. Such contracts are, therefore, always within the scope of IAS 32 and IAS 39 [IAS 32.10; IAS 39.7]. Volume adjustment features are also common, particularly within commodity and energy contracts and are discussed within section 5.3.

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:

- 1) the embedded derivative(s) does not significantly modify the cash flows of the contract; or
- 2) it is clear with little or no analysis that separation of the embedded derivative is prohibited [IAS 39.11A].

Further discussion of embedded derivatives is presented in section 5.4.

5.2 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. Liquefied Natural Gas (LNG) continues to be a growing market and is discussed in section 5.5.

Some of these contracts may be within the scope of IAS 39 if they contain net settlement provisions and do not get 'own use' treatment. These contracts are measured at fair value using the valuation guidance in IFRS 13 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 the price that would be received to sell an asset or paid to transfer a liability (an exit price) by market participants at the measurement date under current market conditions. The valuation of a contract should:

- (a) select inputs that market participants would consider in setting a price, making maximum use of relevant observable inputs and relying as little as possible on unobservable or entity-specific inputs;
- (b) identify the principal or most advantageous market;
- (c) be consistent with accepted economic methodologies for pricing financial instruments; and
- (d) if using unobservable inputs, calibrate the valuation technique(s) to ensure they reflect observable market data e.g. by using prices from any observable current market transactions in the same instrument.

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.

5.2.1 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:

- (a) is evidenced by a quoted price in an active market for an identical asset or liability; or
- (b) is based on valuation techniques whose variables include only data from observable markets [IAS 39 AG 76].

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.

5.3 Volume flexibility (optionality), including 'Take or pay' arrangements

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 the purchaser volume flexibility may have created a written option. Volume flexibility to the extent that a party can choose not to take any volume and instead pay a penalty is referred to as a 'Take or pay' contract. Such flexibility will often prevent the supplier from claiming the 'own use' exemption.

A contract containing a written option must be accounted for in accordance with IAS 39 if it can be settled net in cash, e.g., when the item that is the subject of the contract is readily convertible into cash. Contracts need to be considered on a case-by-case basis in order to determine whether they contain written options.

The nature of end user commodity contracts is that they often have volume optionality but they are accounted for as 'own use'. Although they may include volume flexibility they will not contain a true 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. Therefore it would be 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. Any penalty payable for non-performance by the buyer may well amount to the receipt of a premium. Another factor which may be used to determine if a premium exists is whether usage of a volume option by the purchaser is driven by market conditions or their own physical requirements. In practice, it may be difficult to determine the rationale for the behaviour of a counterparty, but an assessment of the liquidity of the market may provide assistance. A volume option in a contract delivered to a tradable market is more likely than not to cause the contract to fail the 'own use' test.

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 by net settlement of this contract as defined in IAS 39.6.

5.4 Embedded derivatives

Long-term commodity purchase and sale contracts frequently contain a pricing clause (i.e. 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 (i.e. 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 just the embedded derivative. In these situations, the entire combined contract must be measured at fair value under IAS 39, 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.

5.4.1 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.

Management should consider how other contracts for that particular commodity are normally priced in the absence of an active market price for a particular commodity. A pricing formula will often emerge as a commonly used 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.

Embedded derivatives

Entity A enters into a gas delivery contract with entity B, which is based in a different country. There is no active market for gas in either country. The price specified in the contract is based on Tapis-crude, which is the Malaysian crude price used as a benchmark for Asia and Australia. Does this pricing mechanism represent an embedded derivative?

Background

Management has a contract to purchase gas. There is no market price. The contract price for gas is therefore linked to the price of oil, for which an active market price is available. Oil is used as a proxy market price for gas. Is management’s solution acceptable?

Solution

No. The indexation to oil does not constitute an embedded derivative. The cash flows under the contract are not modified. Management can only determine the cash flows under the contract by reference to the price of oil.

5.4.2 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 required when there is a significant change in the terms of the contract and in examples given below but is prohibited in all other cases. 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 and also when an entity acquires a subsidiary that holds a contract with an embedded derivative. The date of purchase or acquisition is treated as the date when the entity first becomes party to the contract. Therefore from the new owner's perspective an embedded derivative may now require separation if market conditions have changed since the original assessment date by the entity.

5.5 LNG contracts

The LNG market has been developing and becoming more active over recent years. This development has been mostly emphasised by the fact that more LNG contracts are currently managed with a dual objective:

- to provide a security of supply via long-term bilateral contracts, and
- to benefit from the potential arbitrage between various gas networks across the world which are not connected otherwise.

The application of the 'own use' exemption could become quite complex particularly for the definition of net settlement. The principles of IAS 39.5 to 39.7 should be still applied; however, there may be some practical challenges to this. The explanation of how energy trading units operate in section 5.7 provides some of the practical considerations.

In the absence of a global LNG reference price, most contracts are currently priced based on other energy indices (e.g. Henry Hub Natural gas index, Brent Oil index, etc.). An assessment of the existence of embedded derivatives is required in order to determine whether they are 'closely related' to the host contract at the inception of the contract. In practice it is not uncommon that the pricing within LNG contracts is considered to be closely related if it is based on proxy pricing typical to the industry.

5.6 Hedge accounting

| |
|--|
| Hedge accounting under IFRS 9 is discussed in section 7.1.6. |
|--|

5.6.1 Principles and types of hedging

Entities often manage exposure to financial risks (including commodity price risks) by deciding to which risk, and to what extent, they should be exposed, by monitoring the actual exposure and taking steps to reduce risks to within agreed limits, often through the use of derivatives.

The process of entering into a derivative transaction with a counterparty in the expectation that the transaction will eliminate or reduce an entity's exposure to a particular risk is referred to as hedging. Risk reduction is obtained because the derivative's value or cash flows are expected, wholly or partly, to move inversely and, therefore, offset changes in the value or cash flows of the 'hedged position' or item. Hedging in an economic sense, therefore, concerns the reduction or elimination of different financial risks such as price risk, interest rate risk, currency risk, etc, associated with the hedged position. It is a risk management activity that is now commonplace in many entities.

Once an entity has entered into a hedging transaction, it will be necessary to reflect the transaction in the financial statements of the entity. Accounting for the hedged position should be consistent with the objective of entering into the hedging transaction, which is to eliminate or reduce significantly

specific risks that management considers can have an adverse effect on the entity's financial position and results. This consistency can be achieved if both the hedging instrument and the hedged position are recognised and measured on symmetrical bases and offsetting gains and losses are reported in profit or loss in the same periods. Without hedge accounting, mismatches would occur under recognition and measurement standards and practices set out in IFRS. Hedge accounting practices have been developed to avoid or mitigate these mismatches.

Hedge accounting rules allow modifying the normal basis for recognising gains and losses (or revenues and expenses) on associated hedging instruments and hedged items so that both are recognised in profit or loss in the same accounting period. Hedge accounting gives management the opportunity to eliminate or reduce the income statement volatility that otherwise would arise if the hedged items and hedging instruments were accounted for separately, without regard to the hedge's documented and designated business purpose.

IAS 39 defines three types of hedge:

- a) Cash flow hedge – a hedge of the exposure to variability in cash flows that (i) is attributable to a particular risk associated with a recognised asset or liability (such as all or some future interest payments on variable rate debt) or a highly probable forecast transaction and (ii) could affect profit or loss. This is the most common type of a hedge in the oil and gas industry.
- b) Fair value hedge – a hedge of the exposure to changes in fair value of a recognised asset or liability or an unrecognised firm commitment, or an identified portion of such an asset, liability or firm commitment, that is attributable to a particular risk and could affect profit or loss.
- c) Hedge of a net investment in a foreign operation as defined in IAS 21.

To comply with the requirements of IAS 39 hedges must be:

- documented from inception of the hedge relationship;
- expected to be highly effective; and
- demonstrated to have been highly effective in mitigating the hedged risk in the hedged item.

There is no prescribed single method for assessing hedge effectiveness. Instead, a company must identify a method that is appropriate to the nature of the risk being hedged and the type of hedging instrument used. The method an entity adopts for assessing hedge effectiveness depends on its risk management strategy. A company must document at the inception of the hedge how effectiveness will be assessed and then apply that effectiveness test on a consistent basis for the duration of the hedge. The hedge must be expected to be effective at the inception of the hedge and in subsequent periods and the actual results of the hedge should be within a range of 80-125% (i.e. changes in the fair value or cash flows of the hedged item should be between 80% and 125% of the changes in fair value or cash flows of the hedging instrument). The effective part of a cash flow hedge and a net investment hedge is recognised in Other Comprehensive Income and the effective part of a fair value hedge is adjusted against the carrying amount of the hedged item. Any ineffectiveness of an effective hedge must be recognised in the income statement. The requirement for testing effectiveness can be quite onerous.

Effectiveness tests need to be performed for each hedging relationship at least as frequently as financial information is prepared, which for listed companies could be up to four times a year. Experience shows that the application of hedge accounting is not straightforward, particularly in the area of effectiveness testing, and a company looking to apply hedge accounting to its commodity hedges needs to invest time in ensuring that appropriate effectiveness tests are developed.

Companies that combine commodity risk from different business units before entering into external transactions to offset the net risk position typically have to designate the hedged item as a part of one of the gross positions, as IAS 39 does not permit a net position to be designated as a hedged item.

5.6.2 Cash flow hedges and ‘highly probable’

Hedging of commodity-price risk or its foreign exchange component is often based on expected cash inflows or outflows related to forecasted transactions, and therefore are cash flow hedges. Under IFRS, only a highly probable forecast transaction can be designated as a hedged item in a cash flow hedge relationship. The hedged item must be assessed regularly until the transaction occurs. If the forecasts change and the forecasted transaction is no longer expected to occur, the hedge relationship must be ended immediately and all retained hedging results in the hedging reserve must be recycled to the income statement. Cash flow hedging is not available if an entity is not able to forecast the hedged transactions reliably.

Entities that buy or sell commodities (e.g. energy companies) may designate hedge relationships between hedging instruments, including commodity contracts that are not treated as ‘own use’ contracts, and hedged items. In addition to hedges of foreign currency and interest rate risk, energy companies primarily hedge the exposure to variability in cash flows arising from commodity price risk in forecast purchases and sales.

5.6.3 Hedging of non-financial Items

It is difficult to isolate and measure the appropriate portion of the cash flows or fair value changes attributable to specific risks other than foreign currency risks. Therefore, a hedged item which is a non-financial asset or non-financial liability may be designated as a hedged item only for:

- a) foreign currency risks;
- b) in its entirety for all risks; or
- c) all risks apart from foreign currency risks

In practice the main sources of ineffectiveness in hedging non-financial items arise from differences in location and differences in grade or quality of commodities delivered in the hedged contract compared to the one referenced in the hedging instrument along with fair value movements on other components of the contract such as transport or refining costs.

5.6.4 Reassessment of hedge relationships in business combinations

An acquirer re-designates all hedge relationships of the acquired entity on the basis of the pertinent conditions as they exist at the acquisition date (i.e., as if the hedge relationship started at the acquisition date). Since derivatives previously designated as hedging derivatives would have been entered into by the acquired entity before the acquisition, these contracts are unlikely to have a zero fair value at the time of the acquisition. For cash flow hedges in particular, this is likely to lead to more hedge ineffectiveness in the financial statements of the post-acquisition group and also to more hedge relationships failing to qualify for hedge accounting as a result of failing the hedge effectiveness test.

Some of the option-based derivatives that the acquired entity had designated as hedging instruments may meet the definition of a written option when the acquiring entity reassesses them at the acquisition date. Consequently, the acquiring entity won't be able to designate such derivatives as hedging instruments.

5.7 Centralised trading units

Many entities have established centralised trading or risk management units in response to the increasing volatility and further sophistication of energy markets. The operation of such a central trading unit may be similar to the operation of the trading units of banks.

The scale and scope of the unit's activities may vary from market risk management through to dynamic profit optimisation. An integrated entity with significant upstream and downstream operations is particularly exposed to the movements in the prices of commodities such as different oil grades, fuel products and gas (LNG). The trading unit's objectives and activities are indicative of how management of the company operates the business. The central trading unit often operates as an internal market place in larger integrated businesses. The centralised trading function thus 'acquires' all of the entity's exposure to the various commodity risks, and is then responsible for hedging those risks in the external markets.

Some centralised trading departments are also given the authority to enhance the returns obtained from the integrated business by undertaking a degree of speculative trading. A pattern of speculative activity or trading directed to profit maximisation is likely to result in many contracts failing to qualify for the 'own use' exemption.

A centralised trading unit therefore undertakes two classes of transaction:

- a) Transactions that are non-speculative in nature: for example, the purchase of oil to meet the physical requirements of the physical assets and the sale of any fuel produced by a refinery. Contracts for such an activity are sometimes held in a 'physical book'.
- b) Transactions that are speculative in nature, to achieve risk management returns from wholesale trading activities. Contracts for such activity are sometimes held in a 'trading book' and often involve entering into offsetting sales and purchase contracts that are settled on a net basis. Those contracts and all similar contracts (i.e. all contracts in the trading book) do not qualify for the 'own use' exemption and are accounted for as derivatives.

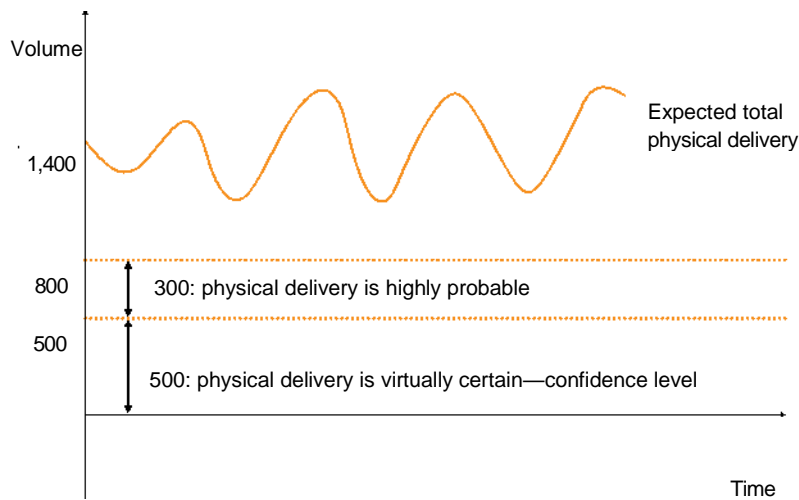
A company that maintains separate physical and trading books needs to maintain the integrity of the two books to ensure that the net settlement of contracts in the trading book does not 'taint' similar contracts in the physical book, thus preventing the 'own use' exemption from applying to contracts in the physical book. Other entities may have active energy trading programmes that go far beyond mitigation of risk. This practice has many similarities to the trading activities of other commodities, such as gold, sugar or wheat.

A contract must meet the 'own use' requirements to be included in the 'own use' or physical book. Contracts must meet the physical requirements of the business at inception and continue to do so for the duration of the contract as discussed in section 5.1.2.

Practical requirements for a contract to be 'own use' are:

- At inception and through its life, the contract has to reduce the market demand or supply requirements of the entity by entering into a purchase contract or a sale contract respectively.
- The market exposure is identified and measured following methodologies documented in the risk management policies of production and distribution. These contracts should be easily identifiable by recording them in separate books.
- If the contract fails to reduce the market demand or supply requirements of the entity or is used for a different purpose, the contract will cease to be accounted for as a contract for 'own use' purposes.
- Own-use treatment could be applied at a gross level, i.e. sale of the oil production does not have to be offset against purchases of oil by the refinery in order to determine an 'own use' level.

- The number of own-use contracts would be capped by reference to virtually certain production and distribution volumes ('confidence levels') to avoid the risk of 'own use' contracts becoming surplus to the inherent physical requirements. If in exceptional circumstances the confidence levels proved to be insufficient, they would have to be adjusted.



The only reason that physical delivery would not take place at the confidence level would be unforeseen operational conditions beyond control of the management of the entity (such as a refinery closure due to a technical fault). Entities would typically designate contracts that fall within the confidence level (with volumes up to 500 in the above diagram) as 'own use', contracts with physical delivery being highly probable (up to 800) as 'all in one' hedges and other contracts where physical delivery is expected but is not highly probable (over 800) as at fair value through profit or loss.

We would expect the result of the operations that are speculative in nature to be reported on a net basis on the face of the income statement. The result could be reported either within revenue or preferably as a separate line (e.g. trading margin) above gross operating profit. Such a disclosure would provide a more accurate reflection of the nature of trading operations than presentation on a gross basis.

Under IFRS 15 the transactions would not meet the definition of revenue from customers and should not be disclosed as such. Refer to 7.2.3.3 for the accounting of these operations.

6. First time adoption

IFRS 1 *First time adoption of IFRSs* provides transition relief and guidance for entities adopting IFRS and it is regularly updated and amended by the IASB. The amendments either update IFRS 1 for new standards and interpretations or address newly identified issues. However, keeping abreast of these changes can be challenging.

Entities in the oil and gas industry face many of the same transition issues as entities in other industries. This section focuses on the specific transition issues and reliefs provided by IFRS 1 that are of particular importance in the industry.

6.1 Deemed cost

Many upstream oil and gas companies used a variant of full cost under local GAAP and will need to make some changes on to IFRS. Successful efforts or a field-by-field based approach needs more detailed information; entities using full cost may not have maintained the detailed records to allow reconstruction of historical cost carrying amounts.

IFRS1 contains specific relief for entities that have previously used full cost accounting. The relief enables a first-time adopter to measure oil and gas assets at the date of transition to IFRS at a 'deemed cost' basis. Exploration and evaluation assets are measured at the carrying value determined under the entity's previous GAAP, this becomes deemed cost for IFRS purposes. The full cost pools are adjusted for the specific allocation of exploration and evaluation. The adjusted cost is then allocated across producing assets and assets under development based on a reasonable method. The assets are then tested for impairment at the date of transition.

This relief applies only to assets used in the exploration, evaluation, development or production of oil and gas. There is a broader 'deemed cost' exemption which can be applied on an asset-by-asset basis to all tangible assets. The broader exemption allows an entity to assess the deemed cost as being:

- the fair value of the asset; or
- a previous GAAP revaluation as deemed cost if the revaluation was broadly comparable to fair value, or to the IFRS cost or depreciated cost adjusted to reflect changes in a price index.

Few first-time adopters have chosen to use the fair value approach. Those that have used it have done so selectively as permitted under the standard. Fair value as deemed cost often results in a significant increase in carrying value with the corresponding credit adjusting retained earnings. There is also a higher depreciation charge in subsequent years.

There is also an exemption that allows the use of fair value for intangible assets at transition to IFRS. However, it requires there to be an active market in the intangible assets as defined in IAS 38; this criterion is not met for common intangibles in the oil and gas industry such as licenses and patents.

6.2 Componentisation

IFRS requires that major assets are depreciated using a componentisation approach. The requirement for component depreciation is the major reason that full cost pools must be allocated to field-size groups of assets. Component depreciation may represent a significant change from practice under national GAAP for oil and gas companies for both upstream and downstream assets.

Refineries are a particular downstream asset where implementing the component approach creates challenges. These are large, complex assets and if detailed asset records have not previously been maintained it can be a major exercise to try to recreate this information. Entities can use the deemed cost exemption previously described if a fair value for the refinery can be determined. It may also be possible to identify the significant components that will require replacement or renewal through

looking at capital budgets and planned replacements. The depreciated carrying amount at transition to IFRS could be estimated through considering replacement cost and timing and making appropriate adjustments.

The deemed cost exemption is only available on initial transition. Subsequent acquisitions will need to follow the componentisation rules prospectively. These are discussed in more detail in sections 2.8.3 and 3.5.

6.3 Decommissioning provisions

Decommissioning provisions are recognised at the present value of expected future cash flows, discounted using a pre-tax discount rate. The discount rate should be updated at each balance sheet date if necessary and should reflect the risks inherent in the asset.

The requirements for a pre-tax rate and periodic updating can also result in differences on adoption of IFRS. An entity's previous GAAP may not have required an obligation to be recognised, allowed a choice of rate or not required the rate to be updated.

Changes in a decommissioning liability are added to or deducted from the cost of the related asset under IFRIC 1. There is an optional short cut method for recognition of decommissioning obligations and the related asset at the date of first time adoption. The entity calculates the liability in accordance with IAS 37 as of the date of transition (the opening balance sheet date). The related asset is derived by discounting the liability back to the date of installation of the asset from the opening balance sheet date. This estimated asset amount at initial recognition is then depreciated to the date of transition using the appropriate method.

Use of the full cost exemption described in section 6.1 means that the IFRIC 1 exemption cannot be used. The entity must measure the decommissioning liability at the date of transition to IFRS and recognise any difference from the carrying amount under previous GAAP as an adjustment to retained earnings.

6.4 Functional currency

IFRS distinguishes between the functional currency and the presentation currency. An entity can choose to present its financial statements in any currency; the functional currency is that of the primary economic environment in which an entity operates. Functional currency must be determined for each entity in the group and is the currency of the primary economic environment in which the specific entity operates. Functional currency is determined by the denomination of revenue and costs and the regulatory and economic environment that has the most significant impact on the entity.

A first-time adopter must determine the functional currency for each entity in the group. Changes of functional currency on adoption of IFRS are not unusual as previous GAAP may have required the use of the domestic currency or allowed a free choice of functional currency. This can result in a significant amount of work to determine the opening balance sheet amounts for all non-monetary assets. An entity needs to determine the historical purchase price in functional currency for all non-monetary assets. These amounts may have been recorded in US dollars, for example. There is no exemption in IFRS 1 for this situation, although use of the fair value as deemed cost exemption may prove less complex and time consuming than reconstruction of historical cost.

Other common foreign currency challenges for oil and gas entities on adoption of IFRS include the impact of hyper-inflation, revaluations of fixed assets in a currency other than the functional currency and the impact on hedging strategies. These can involve significant time and effort to address and need to be considered early during the planning process for transition to IFRS.

IFRS 1 does provide an exemption that allows all cumulative translation differences in equity for all foreign operations to be reset to nil at the date of transition. This exemption is used by virtually all entities on transition to IFRS as the alternative is to recast the results for all foreign operations under IFRS for the history of the entity.

6.5 Assets and liabilities of subsidiaries, associates and joint ventures

A parent or group may well adopt IFRS at a different date from its subsidiaries, associates and joint ventures ('subsidiaries'). Adopting IFRS for the group consolidated financial statements means that the results of the group are presented under IFRS even if the underlying accounting records are maintained under national GAAP, perhaps for statutory or tax reporting purposes.

IFRS 1 provides guidance on a parent adopting IFRS after one or more of its subsidiaries and for subsidiaries adopting after the group. When a parent adopts after one or more subsidiaries, the assets and liabilities of the subsidiary are measured at the same carrying value as in the IFRS financial statements of the subsidiaries after appropriate consolidation and equity accounting adjustments.

A subsidiary that adopts after the group can choose to measure its assets and liabilities at the carrying amounts in the group consolidated financial statements as if no consolidation adjustments (excluding purchase accounting adjustments) were made, or as if the subsidiary were adopting IFRS independently.

6.6 Financial instruments

Embedded derivatives are discussed in section 5.4. Upon adoption of IFRS, an entity must assess whether an embedded derivative is required to be separated from a 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 any reassessment is required.

Therefore, if an entity became a party to a contract containing an embedded derivative prior to the transition date, and the entity is still a party to the contract, the embedded derivative must be recognised as of the IFRS transition date. This would include contracts where the definition of a derivative was not met under previous GAAP.

The embedded derivative would then be measured at fair value using facts and circumstances in existence as of the transition date.

6.7 Impairment

A first time adopter should apply IAS 36 regardless of whether there are any indicators of impairment, to test goodwill for impairment at the date of transition to IFRS, based on conditions at the transition date. Any impairment loss at that date should be recorded in retained earnings.

In addition, IFRS requires that impairment losses be reversed if the circumstances leading to the impairment charge have changed and cause the impairment to be reduced. Some local GAAPs would not have allowed this approach.

6.8 Borrowing costs

The cost of borrowing should be capitalised for qualifying assets. Previous GAAP may also have allowed an entity to expense borrowing costs. IAS 23 *Borrowing costs* is mandatory from the date of transition; however, an entity can choose to adopt it with effect from an earlier date.

Transitioning entities must determine the date from which they will apply the standard, identify all qualifying projects commencing after that date and capitalise costs accordingly. The deemed cost exemption described in section 6.1 above may provide some relief where an entity does not have the

detailed records to perform this for all qualifying assets. IFRS 1 also provides a separate exemption from restating any borrowing cost component capitalised under a previous GAAP – instead, for qualifying assets under construction at the date of transition, IAS 23 requirements are only applied to borrowing costs incurred after that date.

An entity's previous GAAP may also have allowed the capitalisation of borrowing costs for investments accounted for using the equity method of accounting. An investment in an associate or joint venture would not meet the IAS 23 definition of a qualifying asset. The associate or joint venture may only capitalise borrowing costs if they have their own borrowings and a qualifying asset.

Therefore, an entity should consider whether it needs to make any adjustments to reverse previously capitalised interest on transition.

6.9 Disclosure requirements

A first-time adopter is required to present disclosures that explain how the entity's financial statements were affected by the transition from previous GAAP to IFRS. These include:

- an opening balance sheet, prepared as at the transition date, with related footnote disclosure;
- reconciliation of equity reported in accordance with previous GAAP to equity in accordance with IFRS;
- reconciliation of total comprehensive income in accordance with IFRSs to the latest period in the entity's most recent annual financial statements;
- sufficient disclosure to explain the nature of the main adjustments that would make it comply with IFRS.

If the entity used the deemed cost exemption, the aggregate of the fair values used and aggregate adjustment to the carrying amounts reported under previous GAAP.

IAS 36 disclosures if impairment losses are recognised in the opening balance sheet.

Some common adjustments applicable to first-time adopters of the oil and gas industry are:

- use of deemed cost as fair value for assets;
- depletion for oil and gas properties on the UOP method under IFRS;
- reversal of impairment losses recognised under previous GAAP;
- componentisation approach for major refineries based on the capitalisation criteria of major turnarounds under IFRS;
- derivative contracts that do not qualify for hedging under IFRS;
- downstream petroleum product inventory valued using FIFO or weighted average method as opposed to LIFO;
- consequential adjustments to deferred tax under IFRS produced by some of the previous adjustments.

7. New standards – IFRS 9, 15 and 16

The IASB has been very active over the last several years. This section focuses on those standards which have been issued and are not yet effective as of 1 January 2017. Ongoing projects which have not been finalised will be examined in separate publications as the development of those standards progresses.

No decision has been taken on next steps for the Extractive Activities project. It will be considered as part of the wider agenda consultation.

7.1 IFRS 9

IFRS 9 *Financial instruments* addresses classification and measurement, hedging and impairment of financial assets and liabilities. It replaces the existing guidance under IAS 39 from 1 January 2018. Early adoption is permitted. IFRS 9 is generally applied retrospectively (with some exceptions for hedge accounting). Comparative periods do not need to be restated. Entities are permitted to restate comparatives if they can do so without the use of hindsight. If an entity does not restate comparatives, it should adjust the opening balance of its retained earnings for the effect of applying the standard in the year of initial application.

For debt instruments, IFRS 9 emphasises the entity's business model and characteristics of the instruments' contractual cash flows. Debt instruments may be classified as fair value through profit or loss, fair value through other comprehensive income or at amortised cost depending on the assessment of these criteria. For equity instruments where the company does not have significant influence, control, or joint control, the entity may choose irrevocably upon initial recognition to classify the instrument at fair value through OCI or fair value through profit and loss. The fair value through OCI category allows for regular dividends to be accounted for through the income statement, but does not allow for recycling of gains and losses recorded in OCI (i.e. there is no recycling of OCI for equity instruments on sale and no testing for impairment).

For financial liabilities designated at fair value through profit and loss, changes in fair value due to an entity's own credit risk would be recorded in OCI rather than net income. This only applies to financial liabilities designated through profit and loss, so would not apply to instruments mandatorily recorded at fair value such as derivative liabilities.

IFRS 9 introduces a new 'expected loss' impairment model which considers more forward looking information in establishing a provision for impairment against debt instruments carried in categories other than fair value through profit and loss. All such debt instruments should have a provision against them, but the amount of the provision may vary from 12 months of expected credit losses to lifetime expected credit losses depending on the circumstances set out in the standard.

Hedge accounting has been substantially revised. Although the types of relationship remain the same (cash flow hedge, fair value hedge, and net investment hedge), different risks may be eligible for designation under the new standard. For example, in certain circumstances non-financial risk components can be designated where they form part of a non-financial hedged item. In addition, there has been substantial relaxation of required effectiveness thresholds, although hedge ineffectiveness continues to be recognised in the income statement.

In addition, there is a new option where an entity may choose not to apply the 'own use' exception for certain non-financial contracts that have net settlement characteristics and where such designation would reduce or eliminate an accounting mismatch. That is, certain contracts that would meet the 'own use' exception can be treated as derivative contracts and recorded at fair value through profit or loss.

7.1.1 How does classification impact the oil and gas sector?

The effect of IFRS 9 on the financial reporting of oil and gas entities is expected to vary significantly depending on an entity's business model, investment objectives, and the nature of the instruments it holds.

7.1.2 What are the key changes for financial assets?

Classification of an instrument under IFRS 9 depends on:

- a) the objective of the business model for the portfolio in which the instrument is held; and
- b) the contractual cash flows under the instrument solely represent payments of principal and interest.

It should be noted that the first test 'business model' would generally be evaluated at a level of aggregation of multiple instruments (e.g. an investment portfolio). The level at which the business model is evaluated will often require significant judgement. The second criteria is generally evaluated for each instrument.

The new standard removes the requirement to separate embedded derivatives from a financial asset. In practice, we expect many contracts that would have contained embedded derivatives under the former standard to be measured at fair value through profit or loss under IFRS 9. For example, convertible bonds held by oil and gas entities would likely fail the solely payment of principal and interest criterion discussed above which would in turn necessitate that they be carried at fair value through profit and loss.

All equity investments should be measured at fair value under IFRS 9. However, management has an irrevocable option chosen at initial recognition to present in other comprehensive income unrealised and realised fair value gains and losses on equity investments that are not held for trading. For an oil and gas company, this may include an interest in a listed junior explorer. Such designation is available on an instrument-by-instrument basis and is irrevocable. There is no subsequent recycling to the income statement of fair value gains and losses on disposal. Dividends from such investments will continue to be recognised in the income statement. This election avoids downside losses being booked to the income statement but also prevents fair value gains from being recorded in income, so entities should carefully weigh whether this election is appropriate for a particular instrument.

IFRS 9 eliminates the exemption from recording certain investments in unquoted equity securities at cost. Under IFRS 9 all equity instruments (public or private) would be carried at fair value, but there is a limited exception for situations where an entity can demonstrate that the cost of an instrument is equivalent to its fair value. Therefore, entities that have significant investments in private companies which have not been recording the investments at fair value may be significantly impacted.

7.1.3 How could current practice change for oil and gas entities?

| Type of instrument/ Categorisation of instrument | Accounting under IAS 39 | Accounting under IFRS 9 | Insight |
|---|---|---|---|
| Investments in equity instruments that are not held for trading purposes (e.g. equity securities of a listed entity). | Usually classified as 'available for sale' with gains/losses deferred in other comprehensive income (but may be measured at fair value through profit or loss depending on the instrument). | Measured at fair value with gains/losses recognised in the income statement or through other comprehensive income if irrevocably elected. Dividends generally continue to be recognised in profit or loss. | Equity securities that are not held for trading can be classified and measured at fair value with gains/losses recognised in other comprehensive income with such gains/losses not subject to recycling to the income statement. This means no charges to the income statement for significant or prolonged impairment on these equity investments, which will reduce volatility in the income statement as a result of the fluctuating share prices. |
| Available for sale debt instruments (e.g. corporate bonds). | Recognised at fair value with gains/losses deferred in other comprehensive income. | Would qualify for fair value through OCI treatment where the instruments have solely payments of principal and interest contractual cash flows and where they are held in a business model with a dual intention of holding for sale or collection of contractual cash flows. | Determining whether the debt instrument meets the solely payment of principal and interest test can be challenging in practice. It involves determining what the bond payments represent. If they represent more than principal and interest on principal outstanding (for example, if they include payments linked to a commodity price), this would need to be classified and measured at fair value with changes in fair value recorded in the income statement. |
| Convertible instruments (e.g. convertible bonds) | Embedded conversion option split out and separately recognised at fair value. The underlying debt instrument is usually measured at amortised cost. | The entire instrument is measured at fair value with gains/losses recognised in the income statement. | Many entities found the separation of conversion options and the requirement to fair value the instrument separately challenging. However, management should be aware that the |

| Type of instrument/ Categorisation of instrument | Accounting under IAS 39 | Accounting under IFRS 9 | Insight |
|--|-----------------------------|---|--|
| | | (Note there is no change for the issuer.) | entire instrument will now generally be measured at fair value. This may result in a more volatile income statement as it will need to have fair value gains/ losses recognised not only on the conversion option, but on the entire instrument. |
| Held-to-maturity investments (e.g. government bonds) | Measured at amortised cost. | Measured at amortised cost where the business model is to hold for collection and where the solely payments of principal and interest contractual cash flow criterion is met. | <p>Certain bonds may contain features incompatible with the solely payments of principal and interest test (e.g. commodity linkage or certain types of prepayment features) and need to be classified at fair value through profit or loss.</p> <p>As the test for business model is a 'portfolio test' there may be less tainting of the amortised cost category where insignificant or unexpected sales occur.</p> |

7.1.4 What are the key changes for financial liabilities?

The main concern in revising IAS 39 for financial liabilities was potentially showing, in the income statement, the impact of 'own credit risk' for liabilities recognised at fair value – that is, fluctuations in value due to changes in the liability's credit risk. This can result in gains being recognised in income when the liability has had a credit downgrade, and losses being recognised when the liability's credit risk improves. Many users found these results counterintuitive, especially when there is no expectation that the change in the liability's credit risk will be realised.

IFRS 9 changes the accounting for financial liabilities that an entity chooses to account for at fair value through profit or loss, using the fair value option. For such liabilities, changes in fair value related to changes in own credit risk are presented separately in other comprehensive income (OCI).

A common reason for electing the fair value option is where entities have embedded derivatives that they do not wish to separate from the host liability. Entities may elect the fair value option where they

have accounting mismatches with assets that are required to be held at fair value through profit or loss.

Financial liabilities that are required to be measured at fair value through profit or loss (as distinct from those that the entity has chosen to measure at fair value through profit or loss) continue to have all fair value movements recognised in profit or loss with no transfer to OCI. This includes all derivatives (such as foreign currency forwards or interest rate swaps), or an entity's own liabilities that it classifies as being held for trading.

Amounts in OCI relating to own credit are not recycled to the income statement even when the liability is derecognised and the amounts are realised. However, the standard does allow transfers within equity.

7.1.5. Accounting for commodity contracts

IFRS 9 introduces an option to designate an 'own use' contract at fair value through profit or loss if it can be net settled as if it were a financial instrument and if this reduces an accounting mismatch e.g. because there is an offsetting contract that must be fair valued. Deciding whether an 'own use' contract meets the criteria to fair value can be complex, particularly for companies which refine/construct underlying commodities into more complex products. If only physical settlement is permitted under the contract, there must be a liquid market for the underlying commodity such that it is readily convertible to cash. [IFRS 9 para 2.5].

IFRS 9 also permits designation of a hybrid contract at fair value through profit or loss if the host is not an asset within IFRS 9's scope and the embedded derivative would otherwise be separable. [IFRS 9 4.1.4 and 4.3.5]

7.1.6 Hedge accounting

Contemporaneous designation and documentation from inception is required for the hedging relationship to meet the hedge effectiveness requirements. These requirements are similar to those under IAS 39 but are phrased differently in IFRS 9.

Hedge documentation should set out how the hedge effectiveness requirements will be assessed. This would include demonstrating that there is an economic relationship between the hedged item and the hedging instrument. In many cases this assessment may be performed on a qualitative basis, though in complex situations quantitative assessments may be required. Entities also need to consider whether credit risk is expected to dominate a hedging relationship and whether the hedge ratio used is appropriate in the circumstances. These assessments should be made each reporting period. Ineffectiveness continues to be measured in profit and loss using the same methodology as the former standard.

IFRS 9 allows for hedging non-financial portions where they are separately identifiable and reliably measurable. Certain risk components may be contractually specified (e.g. Brent + \$7). Other risk components may not be contractually specified and would need to be evaluated in the context of the particular market structure (e.g. evaluating whether the spot market pricing mechanism for a location is based on a particular benchmark). Although this may allow more risk components to be eligible for hedge accounting, demonstrating that non-contractual risk components separately identifiable and reliably measurable can be challenging and sometimes will require modelling of historical data points.

IFRS 9 also makes the accounting for options designated in cash flow hedging relationships more favourable. Under the former standard, generally entities could only designate the intrinsic value of options in a hedging relationship and would record movement in time value of such options through profit and loss, creating significant earnings volatility. Under IFRS 9, an entity can treat an option

premium as a cost of the hedging relationship and defer certain time value changes in OCI throughout the life of the hedging relationship.

Aggregated positions including a derivative may qualify as a hedged item. For example, an entity with a Sterling functional currency may have forecasted sales of oil in USD. The entity may choose initially to hedge the commodity risk of such a purchase in USD (i.e. to fix the sales price in USD) using a forward oil sale derivative contract. Subsequently, the entity may choose to hedge the foreign currency risk associated with the fixed USD cash flows using a Sterling/USD forward contract. The hedged item is the aggregated forecasted sale plus the forward oil sale contract.

It may be possible to fair value 'own use' contracts under IFRS 9 and avoid the complications of hedge accounting.

7.2 Revenue recognition – IFRS 15

7.2.1 How does it impact the oil and gas sector?

Entities in the oil and gas industry can enter into complex contractual arrangements relating to the sale of products or services. These transactions include partnerships with other entities and arrangements for which the consideration is based on future production, agency arrangements, transportation services, provisionally-priced commodity sales contracts and long-term take-or-pay arrangements. The complexities around pricing and delivery are likely to be affected by the new standard, including requirements to identify separate performance obligations and determine the extent to which transaction prices are subject to the risk of significant reversal. The decision of when to recognise revenue and how to measure it under the new standard could become more challenging.

There is also a significant increase in the disclosure required.

7.2.2 Scope

The new revenue standard applies to contracts with customers and does not exclude extractive activities from its scope. Oil and gas entities will need to use judgement as they evaluate whether or not the parties in the transaction have a vendor-customer relationship, and therefore fall within the scope of IFRS 15.

Definition of a customer

A customer is a party that contracts with an entity to obtain goods or services that are the output of that entity's ordinary activities. The scope includes transactions with collaborators or partners if the collaborator or partner obtains goods or services that are the output of the entity's ordinary activities. It excludes transactions where the parties are participating in an activity together and share the risks and benefits of that activity.

Production sharing arrangements

Governments are increasingly using production sharing arrangements (PSAs) to facilitate the exploration and production of their country's hydrocarbon resources by using the expertise of a commercial oil and gas entity. It can be challenging to determine whether the government is a customer, and therefore whether the arrangement is within the scope of IFRS 15. Under a typical PSA, an oil and gas entity will be responsible for all of the exploration costs, as well as some or all of the development and production costs associated with the hydrocarbon interest. In return, the oil and gas

entity is usually entitled to a share of the production, which will allow the recovery of specified costs plus an agreed profit margin.

PSAs, including royalty agreements, are becoming more complex and the terms might vary even within the same jurisdiction. Governments often write specific legislation or regulations for each significant new field. Each PSA should be evaluated and accounted for in accordance with the substance of the arrangement to determine whether the government meets the definition of a customer and is within the scope of the standard:

- A PSA in which the government is not a customer is outside the scope of the new standard. The oil and gas entity would recognise the construction of its own tangible assets and would apply other relevant guidance including guidance on property, plant and equipment, intangible assets and exploration. Revenue would be recognised when the oil and gas entity delivers its share of production to its customers. The cost of the share of production delivered to the government would be an operating cost.
- A PSA in which the government is a customer is in the scope of the new standard. The proposed guidance requires the operator to recognise revenue for the delivery of services, which might include exploration or construction services, in exchange for future production. The future production would be variable non-cash consideration and would affect the measurement of revenue.

Product exchanges

IFRS 15 scopes out non-monetary exchanges, specifically “non-monetary exchanges between entities in the same line of business to facilitate sales to customers other than the parties to the exchange (for example an exchange of oil to fulfil demand on a timely basis in a specified location).” Non-monetary exchanges should be accounted for based on other guidance (paragraph 24 of IAS 16 *Property, plant and equipment* is relevant for non-monetary exchanges of property, plant or equipment).

Non-monetary exchanges between entities in the same line of business to facilitate sales to the end customer are outside the scope of IFRS 15, even if the products are not the same. This might increase the number of transactions outside the scope of the standard.

IFRS 15 also requires that there be a contract with a customer before revenue is recognised. A contract must be approved by a customer and fulfil other conditions such as enforceability at law and collectability. Furthermore, a contract with a customer only exists if it has commercial substance (that is, the entity’s future cash flows are expected to change as a result of the contract). Arrangements not meeting the conditions of a ‘contract with a customer’ would be outside the scope of the standard and revenue should likely not be recorded.

Interaction with other standards

Contracts that are within the scope of other guidance under IFRS, such as financial instruments, are outside the scope of the new standard.

Elements of contracts within the scope of IFRS 16 *Leases* are also outside the scope of the revenue standard. However, a contract may contain a lease and other non-lease elements that are within the scope of IFRS 15.

The standard provides application guidance for evaluating contracts with repurchase arrangements that will assist oil and gas entities in determining whether the arrangement is a sale to a customer, a financing arrangement or a lease. This may impact some tolling agreements with refineries.

7.2.3 Oil and gas balances – overlift and underlift

It is not clear if other parties in a collaborative arrangement will meet the definition of a customer in the standard. Underlift and over-lift transactions might therefore be outside the scope of the standard. Entities will need to make an assessment as to whether an overlifter is a customer, and this judgement should consider all facts and circumstances including the purpose of the arrangement and transactions.

Even if an overlifter meets the definition of a customer, transactions might still be outside the scope of the standard because the transaction is a non-monetary exchange between entities in the same line of business. The accounting might therefore differ from the model applied under current guidance if there is no net cash settlement alternative.

Scope

Contractual arrangements that bind the participating parties and specify their entitlement to the output (usually in proportion to each party's equity interest) are common in the oil and gas industry. These arrangements allow parties to take shares of output in a given period which are different from their entitlement. The contractual arrangement creates an 'obligation' for the underlifter to deliver output to the overlifter.

The obligation would be satisfied and revenue recognised by the underlifter when the output is lifted by the overlifter only if the transaction is in the scope of IFRS 15 because:

- the overlifter meets the definition of a customer in the standard; and
- the transaction is not a non-monetary exchange between entities in the same line of business.

If the overlifter does not meet the definition of a customer or the transaction is a non-monetary exchange, the transaction would be outside the scope of the standard; the underlifter would not recognise revenue from a contract with a customer (that is, arising for the application of IFRS 15) until it took its share of the output and sold it to a third party in a subsequent period.

The underlifter might still recognise a receivable in the scope of IFRS 9 at the time of lifting even when the transaction is outside the scope of the new standard.

Management would need to determine where in the income statement to recognise the credit. The credit would not be recorded within revenue from contracts with customers, as it is outside the scope of the standard. However, it might be recognised as other revenue or other income.

Settlement of the IFRS 9 receivable would occur when the underlifter takes its entitlement in the next period. The receivable is derecognised, and the debit recognised as inventory if the output is retained or as cost of sales if sold to customers.

The overlifter would recognise revenue when it delivered the output it actually lifted to its customers.

Determining the transaction price

Settlement by the overlifter to the under-lifter is usually made via a change in the lifting schedule, which allows the underlifter to take additional liftings in the future.

The additional liftings will be 'non-cash consideration', which will be measured at fair value where the overlifter meets the definition of a customer, and the transaction is not a non-monetary exchange between entities in the same line of business.

The accounting and presentation for the transaction will be similar to current IFRS if an overlifter does meet the definition of a customer, unless the transaction is a non-monetary exchange. When determining the transaction price, the standard requires that non-cash consideration is measured at fair value.

The accounting and presentation for an under-lift might be different from current practice if an overlifter does not meet the definition of a customer. The entity should use judgement in selecting an accounting policy that is relevant and reliable. If the transaction is not a non-monetary exchange, this accounting policy might reflect the principles of the new revenue standard. However, an entity should ensure that any income classified as revenue is consistent with the definition of revenue in the Framework.

The accounting should be based on other guidance, such as IAS 16 *Property, plant and equipment* if the transaction is a non-monetary exchange.

The underlifter will need to recognise the receivable at fair value where the overlifter does not meet the definition of a customer or the transaction is a non-monetary exchange, but the underlifter recognises a receivable in the scope of IFRS 9.

The entity is likely to use an alternative approach and not deplete its PP&E for the volume relating to the underlift if there is no receivable in the scope of IFRS 9.

7.2.4 Agency relationships

The indicators under the new standard are similar to the existing guidance but are provided in a new context. The indicators are designed to help entities determine if they obtain control of the goods or services before transferring control of those goods or services to the customer. The complexity of determining whether the entity is acting as principal or agent appears to be increasing within the industry, particularly in relation to entities that provide value-added services to entities that extract oil and gas such as transportation and distribution.

Principal versus agent considerations

To determine whether an entity is acting as principal or agent the following should be considered:

- an entity must first identify the specified good or service being provided to the customer;
- the unit of account for the principal versus agent assessment is each performance obligation in a contract;
- the indicators in the standard help an entity evaluate whether it is the principal (that is, whether it controls a good or service before it is transferred to a customer); and
- an entity should assess whether it controls services performed by another party (e.g. a subcontractor).

An entity is the principal in an arrangement if it obtains control of the goods or services of another party in advance of transferring control of those goods or services to the customer.

Obtaining title momentarily before transferring a good or service to a customer does not necessarily constitute control.

An entity is an agent if its performance obligation is to arrange for another party to provide the goods or services.

Indicators that the entity is an agent include:

- the other party is primarily responsible for delivering goods or services;
- the entity does not have inventory risk;
- the entity does not have latitude in establishing prices.

An agent recognises revenue for the fee earned for facilitating the transfer of goods or services. Its consideration is the 'net' amount retained after paying the principal for the goods or services that were provided to the customer.

7.2.5 Delivery – cost, insurance and freight versus free on board

An entity will recognise revenue when (or as) a good or service is transferred to the customer and the customer obtains control of that good or service. Control of an asset refers to an entity's ability to direct the use of and obtain substantially all of the remaining benefits (that is, the potential cash inflows or savings in outflows) from the asset.

In both CIF and FOB approaches, contractual terms mean that risk and title and therefore control of the commodity normally pass at the ship's rail. However, the timing of revenue recognition could change under the new standard, depending on the terms of trade. The difference between the shipping terms only affects which party is responsible for freight costs.

Cost, insurance and freight (CIF)

Identifying separate performance obligations

The new standard will require an entity to account for each distinct good or service as a separate performance obligation. Freight services may meet the definition of a distinct service.

Satisfaction of performance obligations

An entity recognises revenue when it satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The new standard lists indicators of control transferring, including an unconditional obligation to pay, legal title, physical possession, transfer of risk and rewards and customer acceptance.

Sales of goods: Revenue is recognised at the point when control transfers to the customer. This will generally follow the terms of the contract and is usually when the goods pass the rail on a vessel selected by the buyer, at which point the buyer will control the goods.

Transportation: A performance obligation for transportation generally meets the criteria for a performance obligation that is settled over a period of time, and revenue will be recognised over the period of transfer to the customer. If it does not meet the criteria, the performance obligation would be settled at a point in time, and revenue would likely be recognised when the customer receives the goods.

The new standard is generally not expected to change the point at which revenue is recognised for the performance obligation to provide goods. However, when an entity is responsible for organising or executing the shipping, it should evaluate whether it has separate performance obligations for the goods and the freight services. This could mean recognition of a portion of the revenue when control of the goods passes and recognition over time for the portion of revenue relating to the freight services. Where freight services are considered to be a separate performance obligation, the entity should also assess whether it is acting as agent or principal, as this might also affect the timing and amount of revenue recognition.

Factors which might indicate that there is a separate performance obligation for transportation include:

- specialisation of any vehicles or technology involved with providing the transportation;
- level of cost, distance or time associated with providing the transportation; and
- whether the terms of the contract allow the customer to opt out of the transportation element and collect the commodity themselves.

There cannot be a separate performance obligation for an entity to transport its own goods (that is, prior to transfer of control of the goods to the customer).

Free on board (FOB)

Identifying separate performance obligations

An entity recognises revenue when it satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service.

The new standard lists indicators of control transferring, including an unconditional obligation to pay, legal title, physical possession, transfer of risk and rewards and customer acceptance.

The new standard is generally not expected to change the point at which revenue is recognised for the performance obligation to provide goods. However, an entity should evaluate whether it has a separate performance obligation for the freight services. This could mean recognition of a portion of the revenue when control of the goods passes and recognition over time for the portion of revenue relating to freight services.

7.2.6 Provisional pricing arrangements

Satisfaction of performance obligations

The sales contract would be in the scope of the new standard. There will be a single performance obligation, being the delivery of the promised product. Revenue will be recognised when the performance obligation is satisfied, which is when the customer obtains control of the product.

Determining the transaction price

The entity will need to determine the transaction price, which is the amount of consideration it expects to be entitled to in the transaction.

Management should first consider whether provisionally priced contracts include embedded derivatives that are in the scope of financial instrument guidance. An oil and gas entity will apply the separation and/or measurement guidance in other standards first, and then apply the guidance in the revenue standard to the remaining portion of the contract.

The transaction price might be variable or contingent on the outcome of future events, which could include provisional pricing arrangements.

Variable consideration is subject to a constraint. The objective of the constraint is that an entity should recognise revenue as performance obligations are satisfied to the extent that it is 'highly probable' that a significant revenue reversal will not occur in future periods. Such a reversal would occur if there is a significant downward adjustment of the cumulative amount of revenue recognised for that performance obligation.

Judgement will be required to determine if there is an amount that is variable consideration and, if so, whether it is subject to a significant reversal. The new standard has a list of factors that could increase the likelihood or magnitude of a revenue reversal.

Management's estimate of the transaction price will be reassessed each reporting period.

Judgement will be required to determine if the provisional pricing results in the identification of an embedded derivative or variable consideration. If the entity determines that the provisional pricing results in variable consideration, further judgement will be required to determine whether the

estimated transaction price is subject to significant reversal. This might be particularly relevant where the final quality of product being delivered will not be known until assessment at its destination. Where price is conditional upon the quality of the product, this is more likely to be variable consideration.

Judgement will also be required to identify the point at which the variable consideration becomes unconditional, and is then considered a financial asset within the scope of IFRS 9/IAS 39.

Where provisional pricing features represent embedded derivatives, oil and gas entities would be required to continue to separate them and recognise and measure them in accordance with financial instrument guidance. However, given the revised presentation requirements in the new standard, it may no longer be appropriate to present movements in the embedded derivative in revenue from contracts with customers.

7.2.7 Take-or-pay and similar long-term supply agreements

Long-term sales contracts are common in the oil and gas industry. Producers and buyers may enter into sales contracts that are often a year or longer in duration to secure supply and reasonable pricing arrangements. Such contracts are often fundamental to supporting the business case or to finance, develop or continue activity at a particular field.

Contracts will typically stipulate the sale of a set volume of product over the period at an agreed price. There are often clauses within the contract relating to price adjustment or escalation over the course of the contract to protect the producer and/or the seller from significant changes to the underlying assumptions in place at the time the contract was signed. Long-term commodity contracts frequently offer the counterparty flexibility and options in relation to the quantity of the commodity to be delivered under the contract.

Oil and gas entities should continue to first assess whether these arrangements represent financial instruments or contain embedded derivatives that should be accounted for under the financial instruments standards (e.g. whether a contract with volume flexibility contains a written option that can be settled net in cash or another financial instrument). In addition, oil and gas entities should continue to evaluate whether such arrangements convey the right to use a specific asset, and therefore constitute a lease under the leasing standards.

Identifying the contract

In relation to take-or-pay contracts, only the minimum amount specified would generally be considered a contract, as this is the only enforceable part of the agreement. Options in the contract to acquire additional volumes will likely be considered a separate contract at the time the customer exercises the option, unless such options provide the customer with a material right. Where there is a material right, the option should be accounted for as a separate performance obligation in the original contract.

A contract may also contain renewal or extension options. These options also need to be considered in the context of whether they provide a material right to the customer. Where such a material right exists it is accounted for as a separate performance obligation or an entity may elect a practical expedient to assume the renewal term in the period over which revenue is recognised [IFRS 15.B43].

Breakage

Customers may not exercise all of their contractual rights to receive a good or service in the future. Unexercised rights are often referred to as breakage.

An entity should recognise estimated breakage as revenue in proportion to the pattern of exercised rights. Management might not be able to conclude whether there will be any breakage, or the extent of such breakage. In this case, they should consider the constraint on variable consideration, including

the need to record any minimum amounts of breakage. Breakage that is not expected to occur should be recognised as revenue when the likelihood of the customer exercising its remaining rights becomes remote. The assessment should be updated at each reporting period.

In take-or-pay arrangements, this may mean that an entity may be able to recognise revenue in relation to breakage amounts in a period earlier than when the breakage occurs, provided that it can demonstrate it expects that the customer will not exercise these rights. Given the nature of these arrangements and the inherent uncertainty in being able to predict a customer's behaviour, it may be difficult to obtain sufficient evidence to meet this requirement.

The new standard will require oil and gas entities to apply judgement in identifying the performance obligations, as well as the reasons for any price changes over the term of the arrangement. These judgements will determine whether the total transaction price is allocated and recognised based on stand-alone selling prices (e.g., using forward curves), contractual pricing, straight line or another basis. Oil and gas entities will also have to consider whether such arrangements include a significant financing component that will have to be accounted for separately.

7.2.8 Significant financing elements

Some contracts contain a financing component (either explicitly or implicitly) because payment by a customer occurs either significantly before or significantly after performance. This timing difference can benefit either the customer, if the entity is financing the customer's purchase, or the entity, if the customer finances the entity's activities by making payments in advance of performance. An entity should reflect the effects of any significant financing benefit on the transaction price.

The amount of revenue recognised differs from the amount of cash received from the customer when an entity determines that a significant financing component exists. Revenue recognised will be less than cash received for payments that are received in arrears of performance, as a portion of the consideration received will be recorded as interest income. Revenue recognised will exceed the cash received for payments that are received in advance of performance, as interest expense will be recorded and increase the amount of revenue recognised.

The longer the period between when a performance obligation is satisfied and when cash is paid for that performance obligation, the more likely it is that a significant financing component exists.

This is particularly relevant for oil and gas entities that have received significant prepayments from a customer for the purchase of a commodity. These arrangements may be obtained in lieu of financing and may contain a significant financing component. Where a significant financing element exists within a contract, the deferred revenue recognised would effectively be accreted through financing costs using a rate at which the vendor would receive financing in a separate transaction with the customer at inception.

7.2.9 Disclosures

IFRS 15 includes a number of extensive disclosure requirements intended to enable users of financial statements to understand the amount, timing, and judgements related to revenue recognition and corresponding cash flows arising from contracts with customers. We highlight below some of the more significant disclosure requirements, but the list is not all-inclusive.

The disclosures include qualitative and quantitative information about:

- contracts with customers;
- the significant judgements, and changes in judgements, made in applying the guidance to those contracts; and
- assets recognised from the costs to obtain or fulfil contracts with customers.

The standard requires disclosures that disaggregate revenue into categories that depict how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The standard contains guidance on how to select categories.

The disclosure requirements are more detailed than currently required under IFRS and focus significantly on the judgements made by management. For example, they include specific disclosures of the estimates used and judgements made in determining the amount and timing of revenue recognition.

The new standard also requires an entity to disclose the amount of its remaining performance obligations and the expected timing of the satisfaction of those performance obligations for contracts with durations of greater than one year, and both quantitative and qualitative explanations of when amounts will be recognised as revenue. This requirement could have a significant impact on the oil and gas industry, where long-term contracts are a significant portion of an entity's business.

7.2.10 Transition

The revenue standard permits entities to apply one of two transition methods: retrospective or modified retrospective. Retrospective application requires applying the new guidance to each prior reporting period presented; however, entities can elect to apply certain practical expedients. Entities electing the modified retrospective transition approach would apply the new guidance only to contracts that are not completed at the adoption date and would not adjust prior reporting periods.

The modified retrospective transition approach is intended to be simpler than full retrospective application; however, there are still challenges associated with that approach, including additional disclosure requirements in the year of adoption. Entities should consider the needs of investors and other users of the financial statements when deciding which transition method to follow.

7.3 Leases – IFRS 16

IFRS 16 is effective for reporting periods beginning on or after 1 January 2019. Earlier application is permitted, but only in conjunction with IFRS 15. This means that an entity is not allowed to apply IFRS 16 before applying IFRS 15.

7.3.1 Scope

IFRS 16 applies to all lease contracts except for:

- leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources;
- leases of biological assets within the scope of IAS 41 *Agriculture* held by lessees;
- service concession arrangements within the scope of IFRIC 12 *Service concession arrangements*;
- licences of intellectual property granted by a lessor within the scope of IFRS 15 *Revenue from contracts with customers*; and
- rights held by a lessee under licensing agreements within the scope of IAS 38 *Intangible assets* for items such as motion picture films, video recordings, plays, manuscripts, patents and copyrights.

A lessee may choose to apply IFRS 16 to leases of intangible assets other than those mentioned above (e.g. to software).

Mineral lease

Background

Company C has rights to extract minerals from property. The rights include rights of surface access only for purposes of extraction (freehold land).

Lease term is one year with perpetual renewal.

Analysis

Mineral leases are specifically outside of the scope of IFRS 16. Surface rights may be out of scope where exclusively used for extractive activities.

Conclusion

This contract is not a lease.

Leases are different from service contracts: a lease provides a customer with the right to control the use of an asset; whereas, in a service contract, the supplier retains control.

IFRS 16 states that a contract contains a lease if:

- there is an **identified asset**; and
- the contract conveys the **right to control the use of the identified asset** for a period of time in exchange for consideration.

7.3.2 Identifiable asset

An asset can be identified either explicitly or implicitly. If explicit, the asset is specified in the contract (for example, by a serial number or a similar identification marking); if implicit, the asset is not mentioned in the contract (so the entity cannot identify the particular asset) but the supplier can fulfil the contract only by the use of a particular asset. In both cases there may be an identified asset.

In any case, there is no identified asset if the supplier has a **substantive right to substitute** the asset. Substitution rights are substantive where the supplier has the practical ability to substitute an alternative asset and would benefit economically from substituting the asset.

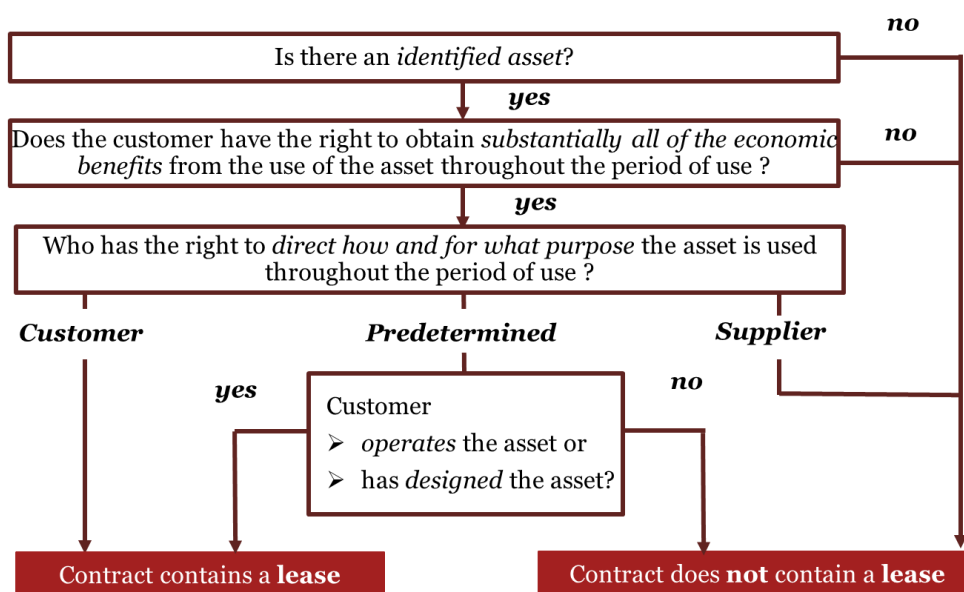
The term 'benefit' is interpreted broadly. For example, the fact that the supplier could deploy a pool of assets more efficiently, by substituting the leased asset from time to time, might create a sufficient benefit as long as there are no significant costs. It is important to note that 'significant' is assessed with reference to the related benefits (that is, costs must be lower than benefits; it is not sufficient if the costs are low or not material to the entity as a whole). Significant costs could occur, in particular, if the underlying asset is tailored for use by the customer. For example, a leased aircraft might have specific interior and exterior specifications defined by the customer. In such a scenario, substituting the aircraft throughout the lease term could create significant costs that would discourage the supplier from doing so.

The assessment whether a substitution right is substantive depends on the facts and circumstances at inception of the contract and does not take into account circumstances that are not considered likely to occur.

A right to substitute an asset if it is not operating properly, or if there is a technical update required, does not prevent the contract from being dependent on an identified asset. The same is true for a supplier's right or obligation to substitute an underlying asset for any reason on or after a particular date or on the occurrence of a specified event because the supplier does not have the practical ability to substitute alternative assets throughout the period of use.

If the customer cannot readily determine whether the supplier has a substantive substitution right, it is presumed that the right is not substantive (that is, that the contract depends on an identified asset).

7.3.3 Determining whether a contract contains a lease



Contracts often combine different kinds of obligations of the supplier, which might be a combination of lease components or a combination of lease and non-lease components. For example, the lease of an industrial area might contain the lease of land, buildings and equipment, or a contract for a car lease might be combined with maintenance.

Where such a multi-element arrangement exists, IFRS 16 requires each separate lease component to be identified (based on the guidance on the definition of a lease) and accounted for separately.

The right to use an asset is a separate lease component if both of the following criteria are met:

- the lessee can **benefit from use of the asset** either on its own or together with other resources that are readily available to the lessee; and
- the underlying asset is **neither highly dependent** on, nor **highly interrelated** with, the other underlying assets in the contract.

If the analysis concludes that there are separate lease and non-lease components, the consideration must be allocated between the components as follows:

- Lessee: The lessee allocates the consideration on the basis of relative stand-alone prices. If observable stand-alone prices are not readily available, the lessee shall estimate the prices, and should maximise the use of observable information.
- Lessor: The lessor allocates the consideration in accordance with IFRS 15 (that is, on the basis of relative stand-alone *selling* prices).

As a **practical expedient**, lessees are allowed not to separate lease and non-lease components and, instead, account for each lease component and any associated non-lease components as a single lease component. This accounting policy choice has to be made by class of underlying asset. Because not separating a non-lease component would increase the lessee's lease liability, the Board expects that a lessee will use this exemption only if the service component is not significant.

Multi-shipper pipeline

Background

Company P operates and maintains the natural gas pipeline. Several companies enter into agreements with P for various volumes of the pipeline capacity: two or more companies are substantive firm service customers and there are several other interruptible customers.

Analysis

Step 1: Is there an identified asset?

No. The leased asset is the capacity portion of the pipeline. None of the customers uses substantially all of the pipeline capacity.

Step 2: Does the customer have a right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use?

A single purchaser will not obtain substantially all the economic benefits from the use of the pipeline capacity during the terms of the arrangement.

Conclusion

This contract does not contain a lease. None of the customers use substantially all of the pipeline's capacity.

Single user pipeline

Background

Company P operates and maintains the natural gas pipeline. Company E enters into an agreement with P for all capacity of this specified pipeline. Company E has uninterruptible service and dispatch rights.

Company E makes the relevant decisions about how and for what purpose the pipeline will be used by determining when and how much natural gas will be transported through the pipeline during the period of use.

Analysis

Step 1: Is there an identified asset?

Yes. The leased asset is the capacity portion of the pipeline. Company E uses all of the pipeline capacity.

Step 2: Does the customer have a right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use?

Company E will obtain substantially all the economic benefits from the use of the pipeline capacity during the terms of the arrangement.

Step 3: The rights to direct the use of the asset

The rights to direct the use of the asset is controlled by company E.

Conclusion

This contract is a lease of the pipeline.

Company E uses 100% of the pipeline's capacity. The fulfilment of the contract is dependent upon an identified pipeline.

Drilling contract (1)

Background

Company A owns drilling rigs and leases them to E&P companies. Company A operates based on locations directed by E&P companies.

Company Q (purchaser) contracts for exclusive use of a drilling rig for a two year period in a remote location. The drilling rig is not of a specialised nature and the contract allows for substitution, but company A would be responsible for significant mobilisation costs if the assets are substituted.

Useful life of drilling rig is 15 years.

Analysis

Step 1: Is there an identified asset?

There is an identified asset. Substitution right is possible per the terms of the contract but is not substantive as company A would not benefit economically from substitution. Company A would have to bear the significant mobilisation costs if assets are substituted.

Step 2: Does the customer have a right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use?

As it is exclusive use, substantially all the benefits accrue to company Q (the E&P company) during the contract term.

Step 3: The rights to direct the use of the asset

The most important decisions about rights to direct the use of the asset (drilling locations) appear to be controlled by company Q (the purchaser).

Conclusion

This contract is a lease of the drilling rig.

Drilling contract (2)

Background

Company A owns 50 drilling rigs and leases them to E&P companies. Company A operates based on locations directed by E&P companies.

Company Q (purchaser) contracts for exclusive use of a drilling rig for a two year period in a location where there is an active drilling market. The drilling rig is not of a specialised nature and contract allows for substitution. Company A often substitutes rigs to reduce transportation costs. This is evident based on past history.

Useful life of drilling rig is 15 years.

Analysis

Step 1: Is there an identified asset?

Substitution is possible. It appears to be economic rationale for company A to substitute other assets. The drilling rig is not specialised and 50 others are available. Past history supports that substitution happens.

Conclusion

This contract is likely not to be a lease. The final conclusion depends on whether or not the substitution right is considered substantive.

Drilling contract (3)

Background

Company A owns drilling rigs and leases them to E&P companies. Company A operates based on locations directed by E&P companies.

Company Q (purchaser) contracts for exclusive use of a drilling rig for a six month period in a remote location. The contract does not contain a renewal option. The drilling rig is not of a specialised nature and the contract allows for substitution, but company A would be responsible for significant mobilisation costs if assets are substituted.

Useful life of drilling rig is 15 years.

Analysis

Step 1: Is there an identified asset?

There is an identified asset. Substitution is possible per the terms of the contract but is not substantive as company A would not benefit economically from substitution. Company A would have to bear the significant mobilisation costs if assets are substituted.

Step 2: Does the customer have a right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use?

As it is exclusive use, substantially all the benefits accrue to company Q (the E&P company) during the contract term.

Step 3: The rights to direct the use of the asset

The most important decisions about rights to direct the use of the asset (drilling locations) appear to be controlled by company Q (the purchaser).

Conclusion

This contract is likely to be a lease, except for the short-term nature of the contract. Company A should account for this contract as a lease. Company Q (purchaser) may choose to exempt the contract from lease accounting. Lease payments could be recorded as operating expenses or capitalised in the cost of PPE.

Interaction between IFRS 15 and IFRS 16

IFRS 15 contains guidance on how to evaluate whether a good or service promised to a customer is distinct for lessors. The question arises of how IFRS 16 interacts with IFRS 15.

For a multi-element arrangement that contains (or might contain) a lease, the lessor has to perform the assessment as follows:

- 1) Apply the guidance in IFRS 16 to assess whether the contract contains one or more lease components.
- 2) Apply the guidance in IFRS 16 to assess whether different lease components have to be accounted for separately.
- 3) After identifying the lease components under IFRS 16, the non-lease components should be assessed under IFRS 15 for separate performance obligations.

The criteria in IFRS 16 for the separation of lease components are similar to the criteria in IFRS 15 for analysing whether a good or service promised to a customer is distinct.

7.3.4 Lease term

The lease term is defined as the **non-cancellable period** of the lease plus periods covered by an **option to extend** or an **option to terminate** if the lessee is reasonably certain to exercise the extension option or not exercise the termination option.

The interpretation of the term '**reasonably certain**' has been a source of controversial discussions, under IAS 17, that led to diversity in practice. To address this, the standard states the principle that all facts and circumstances creating an economic incentive for the lessee to exercise the option must be considered, and provides some examples of such factors:

- *Contractual terms and conditions for optional periods compared with market rates.* It is more likely that a lessee will not exercise an extension option if lease payments exceed market rates. Other examples of terms that should be taken into account are termination penalties or residual value guarantees.
- *Significant leasehold improvements undertaken (or expected to be undertaken).* It is more likely that a lessee will exercise an extension option if a lessee has made significant investments to improve the leased asset or to tailor it for its special needs.
- *Costs relating to the termination of the lease/signing of a replacement lease.* It is more likely that a lessee will exercise an extension option if doing so avoids costs such as negotiation costs, relocation costs, costs of identifying another suitable asset, costs of integrating a new asset and costs of returning the original asset in a contractually specified condition or to a contractually specified location.
- *The importance of the underlying asset to the lessee's operations.* It is more likely that a lessee will exercise an extension option if the underlying asset is specialised or if suitable alternatives are not available.
- If an option is combined with one or more other features such as for example a residual value guarantee with the effect that the cash return for the lessor is the same regardless of whether the option is exercised, an entity shall assume that the lessee is reasonably certain to exercise the option to extend the lease, or not to exercise the option to terminate the lease.

When the option can only be exercised if one or more conditions are met, the likelihood that those conditions will exist should also be taken into account.

The lessee's past practice regarding the period over which it has typically used particular types of assets, and its economic reasons for doing so, may also provide helpful information.

The assessment of whether the exercise of an option is reasonably certain is made at the commencement date (that is, the date on which the lessor makes the underlying asset available for use).

The lease term is **reassessed in only limited circumstances**:

- where the lessee exercises or does not exercise an option in a different way than the entity had previously determined was reasonably certain;
- where an event occurs that contractually obliges the lessee to exercise an option (prohibits the lessee from exercising an option) not previously included in the determination of the lease term (previously included in the determination of the lease term); or
- where a significant event or change in circumstances occurs that is within the control of the lessee and affects whether it is reasonably certain to exercise an option. This trigger is only relevant for the lessee (and not the lessor).

This approach is similar to the one for impairment testing – a reassessment is only made if there are indicators that it would result in a different outcome.

7.3.5 Recognition and measurement exemptions

The standard contains two recognition and measurement exemptions. Both exemptions are optional and they only apply to lessees. If one of these exemptions is applied, the leases are accounted for in a way that is **similar** to current **operating lease accounting** (that is, payments are recognised on a straight line basis or another systematic basis that is more representative of the pattern of the lessee's benefit):

- **Short-term leases:** Short-term leases are defined as leases with a lease term of 12 months or less. The lease term also includes periods covered by an option to extend or an option to terminate if the lessee is reasonably certain to exercise the extension option or not exercise the termination option. A lease that contains a purchase option is not a short-term lease. If a lessee elects this exemption, it has to be made *by class* of underlying asset.

If an entity applies the short-term lease exemption it shall treat any subsequent modification or change in lease term as resulting in a new lease.

- **Leases for which the underlying asset is of low value:** The standard does not define the term 'low value', but the Basis for Conclusions explains that the Board had in mind assets of a value of USD5,000 or less when new. Examples of assets of low value are IT equipment or office furniture. For certain assets (such as assets that are dependent on, or highly interrelated with, other underlying assets), the exemption is not applicable.

The election can be made on a *lease-by-lease* basis. It is important to note that the analysis does not take into account whether low-value assets in aggregate are material. Accordingly, although the aggregated value of the assets captured by the exemption may be material, the exemption is still available.

IFRS 16 also clarifies that both a lessee and a lessor can apply the standard to a **portfolio** of leases with similar characteristics if the entity reasonably expects that the resulting effect is not materially different from applying the standard on a lease-by-lease basis.

7.3.6 Lessee accounting

Initial recognition and measurement

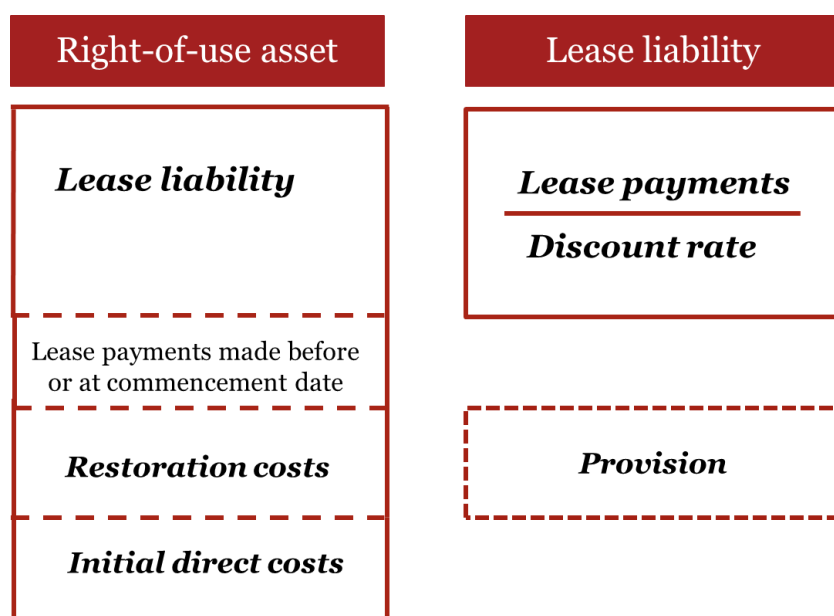
Under IFRS 16, lessees will no longer distinguish between finance lease contracts (on balance sheet) and operating lease contracts (off balance sheet), but they are required to recognise a **right-of-use asset** and a corresponding **lease liability** for almost all lease contracts. This is based on the

principle that, in economic terms, a lease contract is the acquisition of a right to use an underlying asset with the purchase price paid in instalments.

The effect of this approach is a substantial increase in the amount of recognised financial liabilities and assets for entities that have entered into significant lease contracts that are currently classified as operating leases.

The lease liability is initially recognised at the commencement day and measured at an amount equal to the present value of the lease payments during the lease term that are not yet paid; the right-of-use asset is initially recognised at the commencement day and measured at cost, consisting of the amount of the initial measurement of the lease liability, plus any lease payments made to the lessor at or before the commencement date less any lease incentives received, the initial estimate of restoration costs and any initial direct costs incurred by the lessee. The provision for the restoration costs is recognised as a separate liability.

Initial measurement of a right-of-use asset and a lease liability



Lease payments

Lease payments consist of the following **components**:

- fixed payments (including in-substance fixed payments), less any lease incentives receivable;
- variable lease payments that depend on an index or a rate;
- amounts expected to be payable by the lessee under residual value guarantees;
- the exercise price of a purchase option (if the lessee is reasonably certain to exercise that option); and
- payments of penalties for terminating the lease (if the lease term reflects the lessee exercising the option to terminate the lease).

IFRS 16 distinguishes between three kinds of **contingent payments**, depending on the underlying variable and the probability that they actually result in payments:

- (i) *Variable lease payments based on an index or a rate.* Variable lease payments based on an index or a rate (for example, linked to a consumer price index, a benchmark interest rate or a market rental rate) are part of the lease liability. From the perspective of the lessee, these payments are unavoidable, because any uncertainty relates only to the measurement of the liability but not to its existence. Variable lease payments based on an index or a rate are initially measured using the index or the rate at the commencement date (instead of forward rates/indices). This means that an entity does not forecast future changes of the index/rate; these changes are taken into account at the point in time in which lease payments change. The

accounting for variable lease payments that depend on an index or a rate is illustrated in the example on page 18.

- (ii) **Variable lease payments based on any other variable.** Variable lease payments not based on an index or a rate are not part of the lease liability. These include payments linked to a lessee's performance derived from the underlying asset, such as payments of a specified percentage of sales made from a retail store or based on the output of a solar or a wind farm. Similarly, payments linked to the use of the underlying asset are excluded from the lease liability, such as payments if the lessee exceeds a specified mileage. Such payments are recognised in profit or loss in the period in which the event or condition that triggers those payments occurs.
- (iii) **In-substance fixed payments.** Lease payments that, in form, contain variability but, in substance, are fixed are included in the lease liability. The standard states that a lease payment is in-substance fixed if there is no genuine variability (for example, where payments must be made if the asset is proved to be capable of operating, or where payments must be made only if an event occurs that has no genuine possibility of not occurring). Furthermore, the existence of a choice for the lessee within a lease agreement can also result in an in-substance fixed payment. If, for example, the lessee has the choice either to extend the lease term or to purchase the underlying asset, the lowest cash outflow (that is, either the discounted lease payments throughout the extension period or the discounted purchase price) represents an in-substance fixed payment. In other words, the entity cannot argue that neither the extension option nor the purchase option will be exercised.

If payments are initially structured as variable lease payments linked to the use of the underlying asset but the variability will be resolved at a later point in time, those payments become in-substance fixed payments when the variability is resolved.

A **residual value guarantee** captures any kind of guarantee made to the lessor that the underlying asset will have a minimum value at the end of the lease term. The Board indicated it believed that a residual value guarantee could be interpreted as an obligation to make payments based on variability in the market price for the underlying asset and is similar to variable lease payments based on an index or a rate.

Discount rate

The lessee uses as the discount rate the **interest rate implicit in the lease** – this is the rate of interest that causes the present value of (a) lease payments and (b) the unguaranteed residual value to equal the sum of (i) the fair value of the underlying asset and (ii) any initial direct costs of the lessor. Determining the interest rate implicit in the lease is a key judgement that can have a significant impact on an entity's financial statements.

If this rate cannot be readily determined, the lessee should instead use its **incremental borrowing rate**.

The incremental borrowing rate is defined as the rate of interest that a lessee would have to pay to borrow, over a similar term and with a similar security, the funds necessary to obtain an asset of a similar value to the cost of the right-of-use asset in a similar economic environment.

Restoration costs

The lessee is often obliged to return the underlying asset to the lessor in a specific condition or to restore the site on which the underlying asset has been located. To reflect this obligation, the lessee recognises a provision in accordance with IAS 37 *Provisions, contingent liabilities and contingent assets*. The initial carrying amount of the provision, if any (that is, the initial estimate of costs to be incurred), should be included in the initial measurement of the right-of-use asset. This corresponds to the accounting for restoration costs in IAS 16 *Property, plant and equipment*.

Any subsequent change in the measurement of the provision, due to a revised estimation of expected restoration costs, is accounted for as an adjustment of the right-of-use asset as required by IFRIC 1 *Changes in existing decommissioning, restoration and similar liabilities*.

Initial direct costs

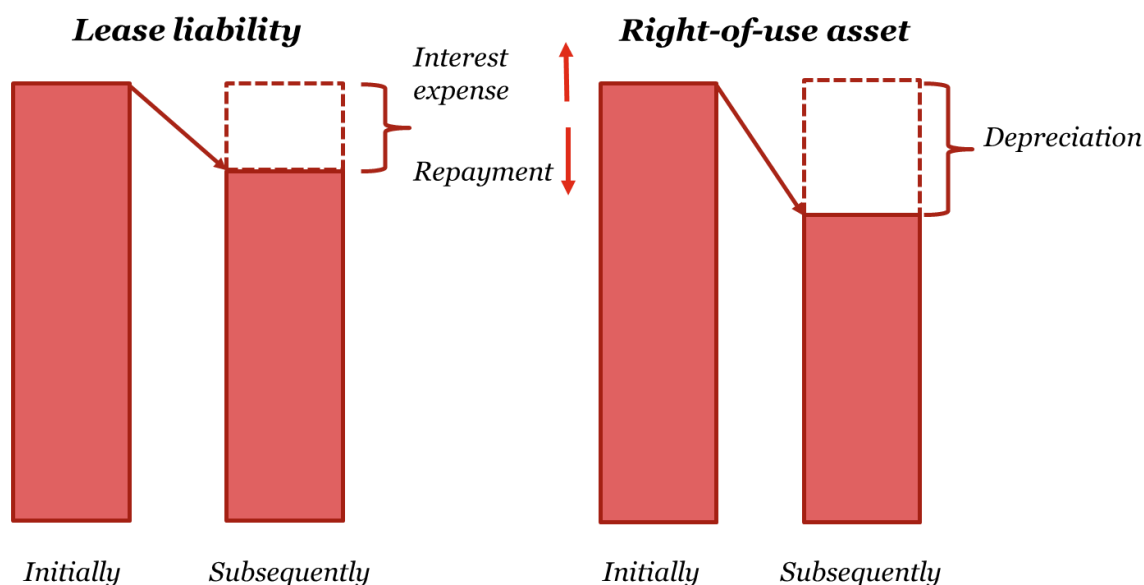
The standard defines initial direct costs as incremental costs that would not have been incurred if a lease had not been obtained. Such costs include commissions or some payments made to existing tenants to obtain the lease. All initial direct costs are included in the initial measurement of the right-of-use asset.

Subsequent measurement

The **lease liability** is measured in subsequent periods using the effective interest rate method. The **right-of-use asset** is depreciated in accordance with the requirements in IAS 16 *Property, plant and equipment* which will result in a depreciation on a straight line basis or another systematic basis that is more representative of the pattern in which the entity expects to consume the right-of-use asset. The lessee must also apply the impairment requirements in IAS 36 *Impairment of assets* to the right-of-use asset.

The carrying amount of the right-of-use asset and the lease liability will no longer be equal in subsequent periods. The carrying amount of the right-of-use asset will, in general, be below the carrying amount of the lease liability.

Subsequent measurement of lease liability and right-of-use asset



Reassessment

As actual lease payments can differ significantly from lease payments incorporated in the lease liability on initial recognition, the standard specifies when the lease liability is to be reassessed. It is important to note that a reassessment only takes place if the change in cash flows is based on contractual clauses that have been part of the contract since inception. Any changes that result from renegotiations are discussed under 'Modification of a lease' below.

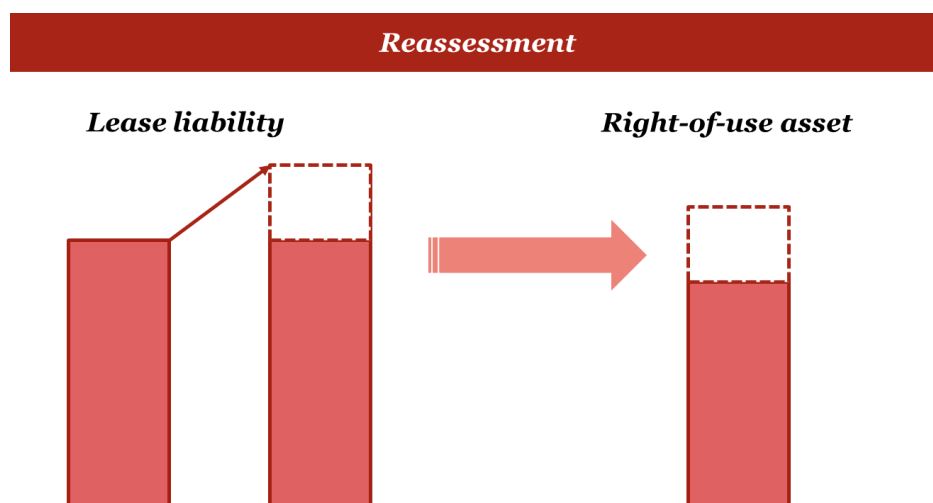
The requirements for **reassessment** are summarised below:

| Component of the lease liability | Reassessment |
|---|---|
| Lease term and associated extension and termination payments | <p>When? – If there is a change in the lease term.</p> <p>How? – Reflect the revised payments using a revised discount rate (the interest rate implicit in the lease for the remainder of lease term (if that rate can be readily determined); otherwise: incremental borrowing rate at the date of reassessment).</p> |
| Exercise price of a purchase option | <p>When? – If a significant event or change in circumstances occurs that is within the control of the lessee and affects whether the lessee is reasonably certain to exercise an option.</p> <p>How? – Reflect the revised payments using a revised discount rate (the interest rate implicit in the lease for the remainder of the lease term (if that rate can be readily determined); otherwise: incremental borrowing rate at the date of reassessment).</p> |
| Amounts expected to be payable under a residual value guarantee | <p>When? – If there is a change in the amount expected to be paid.</p> <p>How? – Include the revised residual payment using the unchanged discount rate.</p> |
| Variable lease payment dependent on an index or a rate | <p>When? – If a change in the index/rate results in a change in cash flows.</p> <p>How? – Reflect the revised payments based on the index/rate at the date when the new cash flows take effect for the remainder of the term using the unchanged discount rate. (Exception: the discount rate has to be updated if the change results from a change in floating interest rates.)</p> |

Aside from this, the lease liability shall be remeasured if payments initially structured as variable payments become in-substance fixed lease payments because the variability is resolved at some point after the commencement date.

Any remeasurement of the lease liability results in a corresponding adjustment of the right-of-use asset. If the carrying amount of the right-of-use asset has already been reduced to zero, the remaining remeasurement is recognised in profit or loss.

Reassessment of a lease liability



The right-of-use asset is also remeasured if the carrying amount of the provision for restoration costs has changed due to a revised estimate of expected costs. In that instance, the change in the carrying amount of the right-of-use asset is equal to the change in the carrying amount of the provision. If adjustments result in an addition, the entity shall consider whether this is an indication that the new carrying amount of the right-of-use asset may not be fully recoverable.

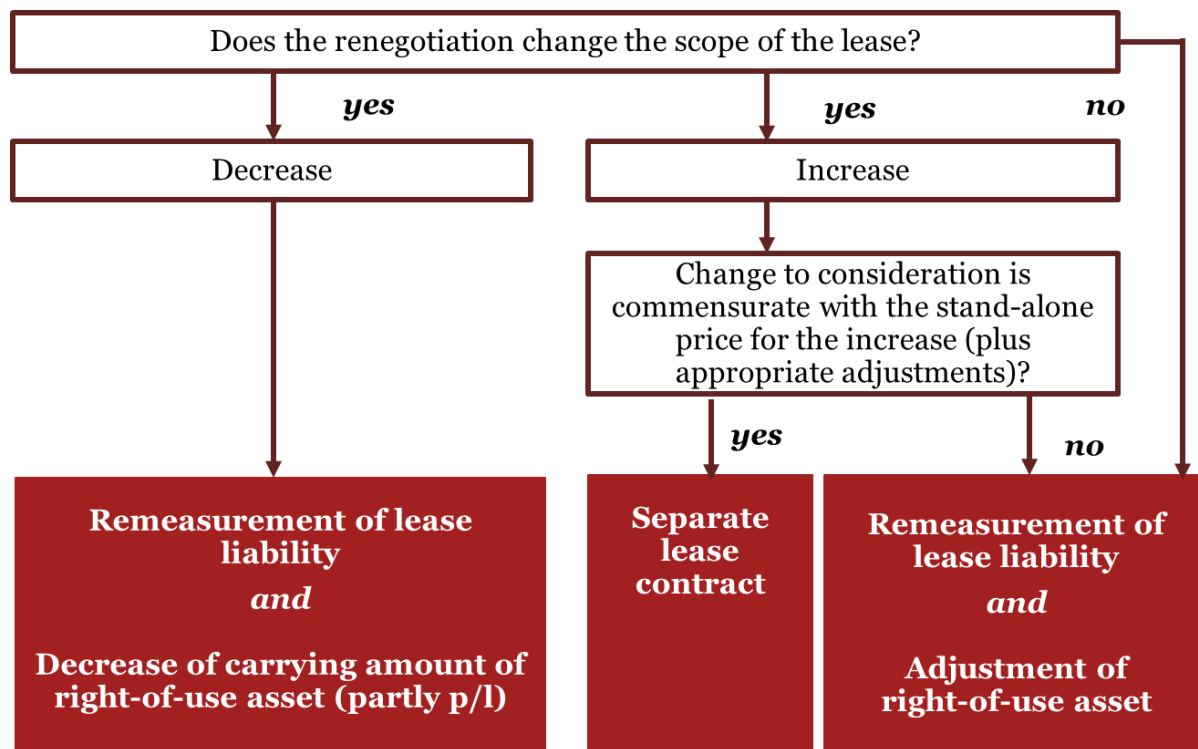
Modification of a lease

There are many different reasons why the parties to a contract might decide to renegotiate and modify an existing lease contract during the lease term. One objective might be to extend or shorten the term of an existing contract (with or without changing the other contractual terms); another reason might be to change the underlying asset (for example, a lessee already leases two floors of a building and the parties agree to add a third one). If the lessee is in financial difficulties, the lessor might agree to reduce lease payments as a concession to support a restructuring.

IFRS 16 defines a modification as a **change in the scope** of a lease, or the **consideration** for a lease, that was **not part of the original terms and conditions** of the lease. Any change that is triggered by a clause that is already part of the original lease contract (including changes due to a market rent review clause or the exercise of an extension option) is not regarded as a modification.

The accounting for the modification of a lease depends on how the contract is modified. The standard distinguishes between three different scenarios:

Modification of a lease



An example for a renegotiation that would result in a change of the scope of the lease would be adding an additional floor to the existing lease of a building for the remaining lease term. The effective date of the modification is the date on which the parties agree to the modification of the lease.

In cases where the modification is not accounted for as a separate lease, the lessee shall, in a first step, allocate the consideration in the modified contract between separate lease and non-lease components and determine the lease term of the modified lease (that is, reassess the previous estimation of the lease term).

Decrease in scope

If the lease is modified to **terminate the right of use of one or more underlying assets** (for example, a lessee already leases three floors of a building and the parties agree to reduce the lease by one floor for the remaining contractual term) or to **shorten the contractual lease term**, the lessee remeasures the lease liability at the effective date of the modification **using a revised discount rate**. The revised discount rate is the interest rate implicit in the lease for the remainder of the lease term (or, if not readily determinable, the lessee's incremental borrowing rate at that time). Furthermore, it decreases the carrying amount of the right-of-use asset to reflect the partial or full termination of the lease. Any gain or loss relating to the partial or full termination is recognised in profit or loss.

Increase in scope

If there has been an **increase in the scope** of the lease *and* the **consideration for the lease increase is commensurate with the stand-alone price for the increase in scope**, the modification is accounted for as a **separate lease**. To be commensurate, the increase in the consideration does not need to be equal to the stand-alone price of the increase in scope. The standard makes clear that any 'appropriate adjustments' to reflect the circumstances of the particular contract are still in line with the assumption that a change in the consideration is commensurate. So for example a discount that reflects the costs the lessor would have incurred when looking for a new lessee (such as marketing costs), may be an appropriate adjustment.

It is important to note that an increase in the scope of the lease only arises if the parties add the right to use one or more underlying assets. The extension of an existing right of use (for example, by a change in the lease term) is not an increase in scope and, therefore, always results in the continuation of the existing lease. However, it is still accounted for as a modification of a lease.

If the consideration paid for the increase in the scope of the lease does **not increase by a commensurate amount** (that is, the stand-alone price for the increase in scope and any appropriate adjustments), the lessee remeasures the lease liability at the effective date of the modification using a revised discount rate and makes a corresponding adjustment to the right-of-use asset.

The revised discount rate is the interest rate implicit in the lease for the remainder of the lease term (or, if not readily determinable, the lessee's incremental borrowing rate at that time).

Change in the lease consideration

If the parties to the contract change the consideration of the lease without increasing or decreasing the scope of the lease, the lessee remeasures the lease liability using the interest rate implicit in the lease for the remainder of the lease term (or, if not readily determinable, the lessee's incremental borrowing rate at the effective date of modification) and makes a corresponding adjustment to the right-of-use asset.

Other measurement models

Aside from the cost model described above, IFRS 16 contains two alternative measurement models that can impact measurement for certain right-of-use assets:

- A right-of-use asset must be subsequently measured in accordance with the fair value model in IAS 40 if the right-of-use asset meets the definition of investment property and the lessee has elected the fair value model in IAS 40.
- A right-of-use asset can be subsequently measured at the revalued amount in accordance with IAS 16 if it relates to a class of property, plant and equipment and the lessee applies the revaluation model to all assets in that class.

Presentation and disclosures

On the **balance sheet**, the right-of-use asset can be presented either separately or in the same line item in which the underlying asset would be presented. The lease liability can be presented either as a separate line item or together with other financial liabilities. If the right-of-use asset and the lease liability are not presented as separate line items, an entity discloses in the notes the carrying amount of those items and the line item in which they are included.

In the **statement of profit or loss and other comprehensive income**, the depreciation charge of the right-of-use asset is presented in the same line item/items in which similar expenses (such as depreciation of property, plant and equipment) are shown. The interest expense on the lease liability is presented as part of finance costs. However, the amount of interest expense on lease liabilities has to be disclosed in the notes.

In the **statement of cash flows**, lease payments are classified consistently with payments on other financial liabilities:

- The part of the lease payment that represents cash payments for the principal portion of the lease liability is presented as a cash flow resulting from financing activities.
- The part of the lease payment that represents interest portion of the lease liability is presented either as an operating cash flow or a cash flow resulting from financing activities (in accordance with the entity's accounting policy regarding the presentation of interest payments).
- Payments on short-term leases, for leases of low-value assets and variable lease payments not included in the measurement of the lease liability, are presented as an operating cash flow.

To provide users with information that allows them to assess the amount, timing and uncertainty of lease payments, IFRS 16 includes enhanced **disclosure** requirements.

7.3.7 Lessor accounting

IFRS 16 does not contain substantial changes to lessor accounting. The lessor still has to classify leases as either finance or operating, depending on whether substantially all of the risk and rewards incidental to ownership of the underlying asset have been transferred. For a finance lease, the lessor recognises a receivable at an amount equal to the net investment in the lease which is the present value of the aggregate of lease payments receivable by the lessor and any unguaranteed residual value. If the contract is classified as an operating lease, the lessor continues to present the underlying assets.

Modification of a lease

The modification of an operating lease should be accounted for as a **new lease by the lessor**. Any prepaid or accrued lease payments are considered to be payments for the new lease (that is, they will be spread over the new term of the modified lease).

A lessor accounts for the modification of a finance lease as a separate lease if:

- the modification increases the scope of the lease; and
- the consideration for the lease increases by an amount commensurate with the stand-alone price for the increase in scope and any appropriate adjustments to that price to reflect the circumstances of the particular contract.

This mirrors the guidance for lessees.

If one of the above criteria is not met, the lessor has to assess whether the modification would have resulted in either an operating or a finance lease if it had been in effect at inception of the lease:

- If the lease would have been classified as an operating lease, the lessor accounts for the modification as a new lease (operating lease). The carrying amount of the underlying asset that has to be recognised is measured as the net investment in the original lease immediately before the lease modification.
- If the lease would have been classified as a finance lease, the lessor accounts for the lease modification in accordance with IFRS 9.

7.3.8 Transition

Entities are not required to reassess existing lease contracts but can elect to apply the guidance regarding the definition of a lease only to contracts entered into (or changed) on or after the date of initial application ('grandfathering'). This applies to both contracts that were not previously identified as containing a lease applying IAS 17/IFRIC 4 and those that were previously identified as leases in IAS 17/IFRIC 4. If an entity chooses this expedient it shall be applied to all of its contracts.

Acknowledging the potentially significant impact of the new lease standard on a lessee's financial statements, IFRS 16 does not require a full retrospective application in accordance with IAS 8 but allows a '**simplified approach**'. Full retrospective application is optional.

If a lessee elects the 'simplified approach', it does not restate comparative information. Instead, the cumulative effect of applying the standard is recognised as an adjustment to the opening balance of retained earnings (or other component of equity, as appropriate) at the date of initial application.

| Balance sheet item | Measurement |
|---|--|
| Leases previously classified as operating leases | |
| Lease liability | Remaining lease payments, discounted using lessee's incremental borrowing rate at the date of initial application. |
| Right-of-use asset | Retrospective calculation, using a discount rate based on lessee's incremental borrowing rate at the date of initial application. <i>or</i> Amount of lease liability (adjusted by the amount of any previously recognised prepaid or accrued lease payments relating to that lease.) <i>(Lessee can choose one of the alternatives on a lease-by-lease basis.)</i> |
| Leases previously classified as finance leases | |
| Lease liability | Carrying amount of the lease liability immediately before the date of initial application. |
| Right-of-use asset | Carrying amount of the lease asset immediately before the date of initial application. |

A lessee is not required to apply the new lessee accounting model to leases for which the lease term ends within 12 months after the date of initial application.

Lessor accounting stays largely the same as under IAS 17. The lessor is not required to make any adjustments on transition except for the reassessment of operating subleases ongoing at the date of initial application.

If an entity chooses not to use the simplified approach, it has to apply IFRS 16 retrospectively to each prior reporting period in accordance with IAS 8 *Accounting policies, changes in accounting estimates, and errors*.

This publication has been prepared for general guidance on matters of interest only, and does not constitute professional advice. You should not act upon the information contained in this publication without obtaining specific professional advice. No representation or warranty (express or implied) is given as to the accuracy or completeness of the information contained in this publication, and, to the extent permitted by law, PwC does not accept or assume any liability, responsibility or duty of care for any consequences of you or anyone else acting, or refraining to act, in reliance on the information contained in this publication or for any decision based on it.

© 2017 PwC. All rights reserved. "PwC" refers to the PwC network and/or one or more of its member firms, each of which is a separate legal entity. Please see www.pwc.com/structure for further details.

170719-094534-CB-OS