

Financial reporting in the power and utilities industry

International Financial Reporting Standards

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Foreword

International Financial Reporting Standards (IFRS) provide the basis for company reporting all over the world. Although the pace of standard-setting from the International Accounting Standards Board (IASB) has been less intense in recent years, the application of new standards still presents challenges for preparers.

One of the biggest challenges of any reporting standard is how best to interpret and implement it in the context of a specific company or industry. In general, IFRS is short on industry guidance. PwC is filling this gap with a regularly updated series of publications that take a sector-by-sector look at IFRS in practice.

In this edition, we look at the issues faced by power and utilities companies. We draw on our considerable experience of helping power and utilities companies apply IFRS effectively and we include a number of real-life examples to show how companies are responding to the various challenges along the value chain.

Of course, it is not just the IFRSs that are constantly evolving, but also the operational issues faced by power and utilities companies. We look at some of the main developments in this context, with a selection of reporting topics that are of most practical relevance to the activities of power and utilities companies.

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



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Introduction

What is the focus of this publication?

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

The need for this publication is driven by the following factors:

- IFRS is a principles-based framework that lacks detailed rules in many areas of interest to utilities.
- The use of IFRS by utilities across a number of jurisdictions, with an acceptance that applying IFRS in this complex industry will be a continual challenge.
- Changing business models in the industry, such that utilities find themselves expanding how they do business; for example, the use of joint arrangements, leasing and tolling activities are all increasing.

Who should use this publication?

This publication is intended for:

- executives and financial managers in the power and utilities industries;
- investors and other users of power and utilities industry financial statements; and
- standard-setters and regulators.

What is included?

This publication addresses the issues that are of most relevance to power and utilities entities.

Many of the issues facing the industry arise from the changing business environment. This discussion focuses on how the broad trends in the industry are affecting business models and creating financial reporting challenges. These trends include:

- growth in merger and acquisition activity;
- continued globalisation;
- sustainability and renewable energy, driving more regulation;
- exposure to sophisticated financial instruments and transactions;
- cost of capital and risk, resulting in increased use of joint arrangements and other cooperative activity; and
- focus on environmental and restoration liabilities.

PwC experience

This publication is based on the experience gained from PwC's worldwide leadership position in the power and utilities industry. This position of leadership enables PwC's Global Power & Utilities Centre of Excellence to make recommendations and lead discussions on international standards and practice.

We hope you find this publication useful.

1 Power and utilities value chain and significant accounting issues

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1.1 Overview

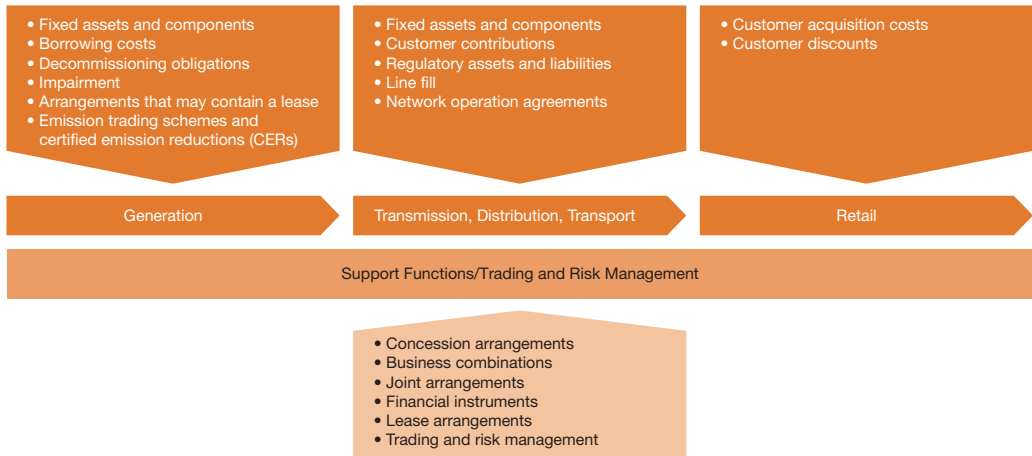
A traditional integrated power entity (utility) generates electricity and sends it around the country or region via high-voltage transmission lines, finally delivering it to customers through a retail distribution network. Some utilities also – or exclusively – transport water and/or gas. As the industry continues to evolve, many operational and regulatory models have emerged. Generators continue to diversify supplies; fossil fuels still dominate, but there is an increasing focus on bio-fuels, co-generation and renewable sources such as wind, solar and wave power. Some governments are supporting the construction of new nuclear power plants and, in some countries, construction has already started; other governments are reconsidering or reversing their support in response to the Fukushima event.

The regulatory environment can be complex and challenging, and it may differ between geographies or even within a country. Pressure to introduce and increase competition and to diversify supply is apparent, as well as schemes that create financial incentives to reduce emissions and increase the use of renewable sources. Previously integrated

businesses might be split by regulation into generation, transmission, distribution and retail businesses. Competition might then be introduced for the generation and retail segments. Generators will look to compete on price and secure long-term fuel supplies, balancing this against potentially volatile market prices for wholesale power. The distribution business might see the incumbent operator forced to grant access to its network to other suppliers. Power customers are beginning to behave like any other group of retail customers: exercising choice, developing brand loyalty, shopping for the best rates, or looking for an attractive bundle of services that might include gas, telephone, water and internet as well as power.

The power and utilities industry is highly regulated, with continuing government involvement in pricing, security of supply and pressure to reduce greenhouse gas emissions and other pollutants. Add this to a background of increased competition, and a challenging financial environment and difficult accounting issues result. This publication examines the accounting issues that are most significant for the utilities industry. The issues are addressed in the order of the utilities value chain: generation, transmission and distribution, and issues that affect the entire entity.

Power and utilities value chain and significant accounting issues



1.2 Generation

Generating assets are often large and complex installations. They are expensive to construct, tend to be exposed to harsh operating conditions and require periodic replacement or repair. This environment leads to specific accounting issues.

1.2.1 Fixed assets and components

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

Identifying components of an asset

Generating assets might comprise a significant number of components, many of which will have differing useful lives. 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 needed for componentisation might not have been required in order to comply with national generally accepted accounting principles (GAAP). This can particularly be an issue for older power plants. However, some regulators require detailed asset records, which can be useful for IFRS component identification purposes.

An entity might look to its operating data if the necessary information for components is not readily identified by the accounting records. Some components can be identified by considering the routine shutdown or overhaul schedules for power stations and the associated replacement and maintenance routines. Consideration should also be given to those components that are prone to technological obsolescence, corrosion or wear and tear that is more severe than that of the other portions of the larger asset.

First-time IFRS adopters can benefit from an exemption under IFRS 1, *First-time Adoption of International Financial Reporting Standards*. This exemption allows entities to use a value that is not depreciated cost in accordance with IAS 16, and IAS 23, *Borrowing Costs*, as deemed cost on transition to IFRS. It is not necessary to apply the exemption to all assets or to a group of assets.

IFRS 14, *Regulatory Deferral Accounts*, was issued in January 2014 as an interim standard on rate-regulated activities. IFRS 14 permits first-time adopters to continue to recognise amounts related to rate regulation in accordance with their previous GAAP accounting policies on adoption of IFRS. However, IFRS 14 requires the effect of rate regulation to be presented separately from other items to enhance comparability with entities that already apply IFRS (and therefore do not recognise such amounts). An entity that already presents IFRS financial statements is not eligible to apply the new guidance.

Depreciation of components

All components should be depreciated to their recoverable amount over their useful lives, which might differ among components. The remaining carrying amount of the component is derecognised on replacement, and the cost of the replacement part is capitalised.

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

1.2.2 Borrowing costs

The cost of an item of property, plant and equipment might include borrowing costs incurred for the purpose of acquiring or constructing it. IAS 23 (revised) requires such borrowing costs to be capitalised if the asset takes a substantial period of time to be prepared for its intended use. Examples of borrowing costs given by the standard are: interest expense calculated using the effective interest method (described in IAS 39, *Financial Instruments: Recognition and Measurement*); finance charges in respect of finance leases recognised in accordance with IAS 17, *Leases*; and exchange differences arising

from foreign currency borrowings to the extent that they are regarded as an adjustment to interest costs.

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

Example

A utility commences construction on a new power plant on 1 September 201X, which continues without interruption until after the year end 31 December 201X. Directly attributable expenditure on this asset is C100 million in September 201X and C250 million in each of the months of October to December 201X. Therefore, the weighted-average carrying amount of the asset during the period is C475 million – that is, (100 million + 350 million + 600 million + 850 million)/4.

The entity has not taken out any specific borrowings to finance the construction of the plant, but it has incurred finance costs on its general borrowings during the construction period. During the year, the entity had 10% debentures in issue, with a face value of C2 billion; and it had an overdraft of C500 million, which increased to C750 million in December 201X and on which interest was paid at 15% until 1 October 201X, when the rate was increased to 16%. The capitalisation rate of the general borrowings of the entity during the period of construction is calculated as follows:

Weighted-average borrowings during period:

$$\begin{aligned} & ((2\text{b} \times 4) + (500 \text{ million} \times 3) + (750 \text{ million} \times 1)) / 4 \\ & = \text{C}2,562,500,000 \end{aligned}$$

$$\begin{aligned} & \text{Capitalisation rate (total finance costs in period /} \\ & \text{weighted-average borrowings during period)} \\ & = 96,250,000 / 2,562,500,000 \\ & = 3.756\% \end{aligned}$$

The capitalisation rate, therefore, reflects the weighted-average cost of borrowings for the four-month period that the asset was under construction. On an annualised basis, 3.756% for the four-month period gives a capitalisation rate of 11.268% per annum, which is what would be expected on the borrowings profile.

Therefore, the total amount of borrowing costs to be capitalised is the weighted-average carrying amount of asset \times capitalisation rate

$$\begin{aligned} & = \text{C}475 \text{ million} \times 11.268\% \times 4/12 \\ & = \text{C}17,841,000 \end{aligned}$$

	C (x1,000)
Finance cost on C2 billion 10% debentures during September–December 201X	66,667
Interest at 15% on overdraft of C500 million in September 201X	6,250
Interest at 16% on overdraft of C500 million in October and November 201X	13,333
Interest at 16% on overdraft of C750 million in December 201X	10,000
Total finance costs in September–December 201X	96,250

Example

A utility uses general borrowings and cash from operating activities to finance its qualifying assets. It has a capital structure of 20% equity and 80% current and non-current liabilities, including

interest-bearing debt from general borrowings. The borrowing rate is applied to the full carrying amount of the qualifying asset, rather than to the 80% of the qualifying assets that are financed with borrowings.

Utilities will sometimes use operating cash flows to finance capital expenditure during a period when there is also general financing. The borrowing rate is applied to the full carrying amount of the qualifying asset. This is the case even where the cash flows from operating activities are sufficient to finance the capital expenditure. IAS 23 (revised) does not deal with the actual or imputed cost of capital.

A utility might contract for a power plant on a turnkey basis. Progress payments will be made by the utility over the construction period of a power plant. The borrowing costs incurred by an entity to finance prepayments made to a third party to acquire the qualifying asset are capitalised in accordance with IAS 23 (revised) on the same basis as the borrowing costs incurred on an asset that is constructed by the entity. Capitalisation starts when all three conditions are met: expenditures are incurred, borrowing costs are incurred, and the activities necessary to prepare the asset for its intended use or sale are in progress. Expenditures on the asset are incurred when the prepayments are made (that is, payments of the instalments). Borrowing costs are incurred when borrowing is obtained. The last condition – the activities necessary to prepare the asset for its intended use or sale – is considered to be met when the manufacturer has started the construction process. Determining whether the construction is in progress requires information directly from the turnkey supplier.

A utility might hedge its borrowings. The effects of cash flow or fair value hedge relationships on borrowing costs are capitalised (this applies to both specific and general borrowings). The hedging relationship modifies the borrowing costs of the utility related to the debt; IAS 23 requires the effective interest rate to be used as the basis for interest capitalisation. A hedge that modifies the amount of borrowing costs should be included in determining the effective interest rate. Ineffectiveness on such hedging relationships should be recognised in profit or loss.

1.2.3 Decommissioning obligations

The power and utilities 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 might be required by law, the terms of operating licences or an entity's stated policy and past practice. An entity that promises to remediate damage, even where there is no legal requirement, might have created a constructive obligation and thus a liability under IFRS. There might also be environmental clean-up obligations for contamination of land that arises during the operating life of a power plant or other installation. The associated costs of remediation/restoration can be significant; so the accounting treatment for decommissioning costs is critical.

Decommissioning provisions

A provision is recognised where an obligation exists to remediate or restore. 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 when the asset is placed in service. Entities recognise decommissioning provisions at the present value of the expected future cash flows that will be required to perform the decommissioning. The cost of the provision is recognised as part of the cost of the asset when it is placed in service, and it is depreciated over the asset's useful life. The total cost of the fixed asset, including the cost of decommissioning, is depreciated on the basis that best reflects the consumption of the economic benefits of the asset.

Provisions for decommissioning and restoration are recognised even if the decommissioning is not expected to be performed for a long time (perhaps 80 to 100 years). The effect of the time to expected decommissioning is 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. Naturally, different decommissioning obligations have different inherent risks (for example, different

uncertainties associated with the methods, and 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.

A similar accounting approach is taken for nuclear fuel rods. These rods are classified as inventory, and an obligation to reprocess them is triggered when the rods are placed into the reactor. A liability is recognised for the reprocessing obligation when the rods are placed into the reactor, and the cost of reprocessing is added to the cost of the fuel rods.

Revisions to decommissioning provisions

Decommissioning provisions are updated at each balance sheet date for changes in the estimates of the amount or timing of future cash flows and changes in the discount rate. Changes to provisions that relate to the removal of an asset are added to or deducted from the carrying amount of the related asset in the current period. Changes to provisions that relate to the removal of an asset no longer used are recognised immediately in the income statement. However, the adjustments to the asset are restricted:

- The asset cannot decrease below zero and cannot increase above its recoverable amount.
- If the decrease to the 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. An impairment test is required if there is an indication that the asset might not be fully recoverable.

The accretion of the discount on a decommissioning liability is recognised as part of finance cost in the income statement.

Decommissioning funds

Power and utilities companies that operate nuclear power plants might, at times, be obliged to contribute to a separate fund established to ensure that decommissioning obligations will be met in the future.

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 sometimes also 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 power and utilities entity then obtains reimbursement of actual decommissioning costs from the fund as they are incurred. However, the power and utilities entity might 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 power and utilities entity. Management must recognise its interest in the fund separately from the liability to pay decommissioning costs. Offsetting is not appropriate.

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 some level of control or influence, the fund is accounted for as a reimbursement of the entity's closure and environmental obligation; the fund is measured 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.

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

1.2.4 Impairment

The utility industry is distinguished by the significant capital investment required, exposure to commodity prices and heavy regulation. The required investment in fixed assets leaves the industry exposed to adverse economic conditions and, therefore, impairment charges. Utilities' assets should be tested for impairment whenever indicators of impairment exist. The normal measurement rules for impairment apply.

Impairment indicators

Examples of external impairment triggers relevant for the utilities industry include falling retail prices, rising fuel costs, overcapacity and increased or adverse regulation or tax changes.

Impairment indicators can also be internal in nature. Evidence that an asset or cash-generating unit (CGU) has been damaged or has become obsolete is an impairment indicator; for example, a power plant destroyed by fire is, in accounting terms, an impaired asset. Other indicators of impairment are a decision to sell or restructure a CGU, or evidence that business performance is less than expected. Performance of an asset or group of assets that is below that expected by management in operational and financial plans is also an indicator of impairment.

Management should be alert to indicators of impairment on a CGU basis; for example, a fire at an individual generating station would be an indicator of impairment for that station as a separate CGU.

Management might also identify impairment indicators on a regional, country or other asset-grouping basis, reflective of how it manages its business. Once an impairment indicator has been identified, the impairment test must be performed at the individual CGU level, even if the indicator was identified at a regional level.

Cash-generating units

A CGU is the smallest group of assets that generates cash inflows largely independently of other assets or groups of assets. In identifying whether cash inflows from an asset or groups of assets are largely independent of the cash inflows from other assets (or groups of assets), CGUs should be identified on a consistent basis from one period to the next for the same assets or types of asset, unless a change is justified. (If an asset is moved to a different CGU, or the types of asset that are aggregated for the asset's CGU have changed and a material impairment is recognised or reversed, the entity should describe the current and former way of aggregating assets and the reasons for the change.)

Determining the CGU and assessing the recoverable amount for an individual CGU is difficult in situations where management has multiple assets and has the ability to choose the assets that are used. If there is an active market for the output produced by an asset or group of assets, that asset or group of assets should be identified as a CGU.

Determination of what is a CGU can be an area of significant judgement but is not an accounting policy

choice. The exercise of such judgement might result in multiple assets being grouped to form a single CGU or being considered as individual CGUs. If this judgement has an impact on whether an impairment is recognised, the judgement and related assumptions might be significant enough to be disclosed as critical judgements under IAS 1.

Calculation of recoverable amount

Impairments are recognised if the carrying amount of a CGU exceeds its recoverable amount; the recoverable amount is the higher of fair value less costs of disposal (FVLCD) and value in use (VIU).

Fair value less costs of disposal

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

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

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

Value in use (VIU)

VIU is the present value of the future cash flows expected to be derived from an asset or CGU in its current condition. Determination of VIU is subject to the explicit requirements of IAS 36, *Impairment of Assets*. The cash flows are based on the asset that the entity has now; they 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. The VIU cash flows for assets 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.

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

The discount rate used for VIU is always pre-tax and applied to pre-tax cash flows. This is often one of the most challenging elements of the impairment test, because pre-tax rates are not available in the marketplace, and arriving at the correct pre-tax rate is a complex mathematical exercise. Computational shortcuts are available if there is a significant amount of headroom in the VIU calculation. However, grossing up the post-tax rate seldom, if ever, gives an accurate estimate of the pre-tax rate.

Contracted cash flows in VIU

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

There might be commodities – both fuel and the resultant electricity output – covered by purchase and sales contracts. Management should use the contracted price in its VIU calculation for any commodities unless the contract is already on the balance sheet at fair value. Including the contracted prices of such a contract would be to double count the effects of the contract. Impairment of financial instruments that are within the scope of IAS 39, *Financial Instruments: Recognition and Measurement*, is addressed by IAS 39 and not IAS 36.

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

1.2.5 Arrangements that might contain a lease

Accounting in this area will change if a new leasing standard is issued as a result of the ongoing IASB project on leases. Reporting entities should continue to monitor the activities of the IASB in this area.

IFRS requires that arrangements that convey the right to use an asset in return for a payment or series of payments be accounted for as a lease, even if the arrangement does not take the legal form of a lease. Some common examples of such arrangements include a series of power plants built to exclusively supply the rail network, or a power plant located on the site of an aluminium smelter or constructed on a build-own-operate-transfer arrangement with a national utility. Tolling arrangements might also convey the use of the asset to the party that supplies the fuel. Such arrangements have become very common in the renewable energy business, where all of the output of wind or solar farms or biomass plants is contracted to a single party under a power purchase agreement.

IFRIC 4, *Determining Whether an Arrangement Contains a Lease*, sets out guidelines to determine when an arrangement might contain a lease. Once a determination is reached that an arrangement contains a lease, the lease arrangement must be classified as either financing or operating, according to the principles in IAS 17, *Leases*. A lease that conveys the majority of the risks and rewards of operation is a finance lease. A lease other than a finance lease is an operating lease.

The classification has significant implications: a lessor in a finance lease would derecognise its generating assets and recognise a finance lease receivable in return; a lessee in a finance lease would recognise fixed assets and a corresponding lease liability, rather than account for the power purchase agreement as an executory contract.

Classification as an operating lease leaves the lessor with the fixed assets on the balance sheet and the lessee with an executory contract.

Power purchase agreements

It can be difficult to determine whether the power purchase agreement contains a lease. The purchaser might take all or substantially all of the output from a specified facility. However, this does not necessarily mean that the entity is paying for the right of use of the asset rather than for its output. If the purchase price is fixed per unit of output, or equal to the current market price at the time of delivery, the purchaser is presumed to be paying for the output rather than leasing the asset.

There has been some debate over the meaning of 'fixed per unit of output' in IFRIC 4, and two approaches have emerged in practice. 'Fixed per unit of output' is interpreted by some entities in a manner that allows for no variability in pricing whatsoever over the entire term of the contract (that is, fixed equals fixed). However, other entities have concluded that the fixed

criterion is met if, at the inception of the arrangement, the purchaser and seller can determine what the exact price will be for every unit of output sold at each point in time during the term of the arrangement (that is, fixed equals predetermined). There is support for both views, and the interpretation of 'fixed' is an accounting policy election. The accounting policy should be disclosed and applied on a consistent basis to all similar transactions.

The following examples aid in the application of the 'fixed equals predetermined' interpretation of contractually fixed per unit of output.

Similar to the 'fixed price per unit' criterion, the market price condition is narrowly interpreted. For example, arrangements that include caps/floors would not be considered to reflect the current market price at the time of delivery, because the price at delivery might be different from the spot market price.

Pricing is contractually predetermined and the fixed price condition is deemed to be met:

- 1) A power purchase agreement under which the purchaser pays C40 for each megawatt-hour (MWh) of electricity received during the first year of the arrangement. The price per MWh increases by 2.5% during each subsequent year of the arrangement.

- 2) A power purchase agreement under which the purchaser pays C75 for each MWh of electricity received during peak hours and C45 for each MWh of electricity received during off-peak hours. Peak hours are defined in the agreement in a manner whereby it can be determined at the inception of the arrangement whether each point in time is considered peak or off-peak. For example: peak hours are from noon to 10:00 p.m. each day during July and August; all other times are considered off-peak.

Pricing is not contractually predetermined and the fixed price condition is deemed to be not met:

- 1) A power purchase agreement under which the purchaser pays C40 for each MWh of electricity received during the first year of the arrangement. The price per MWh increases during each subsequent year of the arrangement based on the annual change in the consumer price index. This price is not predetermined, because it varies with inflation from the second year on.

- 2) A power purchase agreement under which the purchaser pays C40 per MWh plus a C30,000 per month capacity charge. The capacity charge is not payable in any month that the capacity factor drops below 30%. The pricing in this arrangement is not predetermined, because the price per MWh varies with the amount of electricity produced. Although the energy price is fixed, the amount paid per MWh includes the fee for capacity, and monthly changes in production change the average cost per MWh. For example, if the plant produces 15,000 MWh in the first month, the price is C42 per MWh (that is, C40 per MWh energy charge plus C2 per MWh allocated capacity charge). However, if the plant produces only 10,000 MWh, the price is C43 per MWh.

What is output?

It is also important to determine what output should be taken into consideration in order to test whether the contract is, in substance, a lease. One question that arises with renewable plants is whether there

is a power purchase agreement for substantially all, or all, of the output, because the amount of generation is determined by an uncontrollable factor (for example, the wind, sun or rain/snowfall). The following example illustrates this concept.

Wind farm contract

- For 100% of the output of the wind farm for substantially all of the asset's life.
- For substantially all of the asset's life.
- Guarantees a level of availability when the wind is blowing.
- Allows the purchaser to agree the timing of maintenance outages.

The developer/owner of the wind farm agrees to sell 100% of the output of the wind farm to a single purchaser, with the intention that the developer

recovers its operating costs, debt service cost and a development premium. Wind feasibility studies are used to help the siting of wind farms and assess the economic viability early in the development stage of the project.

A power purchase agreement for 100% of the output of a wind farm often contains a lease, even though the generation of electricity is contingent on the wind. The variability in output does not impact the assessment of whether the contract contains a lease.

Another question that arises in lease classification for renewable facilities is whether renewable energy certificates (RECs) are 'output or other utility' in terms of paragraph 9c of IFRIC 4. If the RECs are considered output and sold to another party, more than one party is consuming a substantial amount of the output of the asset under IFRIC 4. Some governments have imposed on electricity suppliers a requirement to source an increasing proportion of electricity from renewable sources. An accredited generator of renewable electricity is granted an REC per MWh of renewable energy generated, to demonstrate that the electricity has been procured from renewable sources.

The determination of whether RECs are 'output or other utility' might impact the evaluation of whether a power purchase agreement contains a lease, particularly where the energy and RECs are sold to different parties.

Two approaches have emerged in practice as to what can be considered output under IFRIC 4. These are explained as follows:

- RECs are output: RECs are considered in the lease evaluation. The construction of a specified facility and the pricing inherent in the contractual arrangements with offtakers are based on the combined benefit of energy, capacity, RECs and any other output from the facility

- RECs are a government incentive: RECs are not considered as an output in the lease analysis. Output is limited to the productive capacity of the specified property and relates only to those products that require 'steel in the ground'. RECs result from a government programme (similar to tax incentives) created to promote construction of the plant and are a paper product, not a physical output.

Although both approaches are supportable, the approach used with RECs is an accounting policy choice, to be applied consistently and to be disclosed.

1.2.6 Emissions trading schemes and certified emission reductions

EU member states have set limits on carbon dioxide emissions from energy-intensive companies under the EU emissions trading scheme. The scheme works on a 'cap and trade' basis, and each EU member state is required to set an emissions cap covering all installations covered by the scheme.

Even after the less specific Copenhagen Accord, the EU cap and trade scheme is still considered to be a model for other governments seeking to reduce emissions.

Additionally, several non-Kyoto carbon markets exist. These include the New South Wales Greenhouse Gas Abatement Scheme, and the Regional Greenhouse Gas Initiative and the Western Climate Initiative in the United States and Canada.

Accounting for emissions trading schemes

The emission rights permit an entity to emit pollutants up to a specified level. The emission rights are given or sold by the government to the emitter for a defined compliance period. Schemes in which the emission rights are tradable allow an entity to do one of the following:

- 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 because of concerns over the consequences of the required accounting. As a result, there is no specific comprehensive accounting for cap and trade schemes or other emission allowances

The guidance in IFRIC 3 remains valid, but entities are free to apply variations, provided that the requirements of all relevant IFRSs are met. Several approaches have emerged in practice under IFRS. The scheme can result in the recognition of assets (allowances), expense of emissions, a liability (obligation to submit allowances) and, potentially, a government grant.

The allowances are intangible assets – often presented as part of inventory – and are recognised at cost if separately acquired. Allowances 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, *Government Grants*.

The allowances recognised are not amortised, provided residual value is at least equal to carrying value. The allowances are recognised in the income statement, because they are delivered to the government in settlement of the liability for emissions on a ‘units of production’ basis.

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

The entity may choose to apply the revaluation model in IAS 38, *Intangible Assets*, for the subsequent measurement of the emissions allowances. The revaluation model requires 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).

A provision is recognised for the obligation to deliver allowances or pay a fine to the extent that pollutants have been emitted because an obligation is created by the emission of the greenhouse gas. The provision is commonly measured at the cost of the certificates acquired, including those acquired for nil cost (for example, under government grants) or the contracted purchase price for planned purchases of certificates. The allowances reduce the provision where 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.

Certified emission reductions

For fast-growing countries and countries in transition that are not subject to a Kyoto target on emissions reduction, another scheme exists under the Kyoto Protocol. Entities in these countries can generate certified emission reductions (CERs). Entities can acquire CERs from existing projects, although new CER projects are not currently accepted in the EU. CERs represent a unit of greenhouse gas reduction that has been generated and certified by the United Nations under the Clean Development Mechanism (CDM) provisions of the Kyoto Protocol. The CDM allows industrialised countries that are committed to reducing their greenhouse gas emissions under the Kyoto protocol to earn emission reduction credits towards Kyoto targets through investment in ‘green’ projects. Examples of projects include reforestation schemes and investment in clean energy technologies. Once received, the CERs have value because they are exchangeable for EU ETS allowances, and hence can be used to meet obligations under that particular scheme.

An entity that acquires CERs accounts for these following the ETS cost model; they are accounted for at cost, at initial recognition, and subsequently in accordance with the accounting policy chosen by the entity. No specific accounting guidance under IFRS covers the generation of CERs. Entities that generate CERs should develop an appropriate accounting policy. Most entities that need CERs are likely to acquire them from third parties and account for them as separately acquired assets. The key question that drives the accounting for self-generated CERs is, 'What is the nature of the CERs?'. The answer to this question lies in the specific circumstances of the entity's core business and processes. If the CERs generated are held for sale in the entity's ordinary course of business, CERs are within the scope of IAS 2, *Inventories*. If they are not held for sale, they should be considered as identifiable non-monetary assets without physical substance (that is, intangible assets – often presented as part of inventory).

The accounting for CERs is also driven by the applicability of IAS 20, *Government Grants and Disclosure of Government Assistance*. If CERs are granted by a government, the accounting would be as follows:

- Recognition when there is a reasonable assurance that the entity will comply with the conditions attached to the CERs and the grant will be received.
- Initial measurement at nominal amount or fair value, depending on the policy choice.
- Subsequent measurement depends on the classification of CERs and should follow the relevant standard (that is, IAS 2, *Inventory*, IAS 38, *Intangible Assets*, or IFRS 5, *Non-current Assets Held for Sale and Discontinued Operations*).

IFRIC 21, *Levies*, sets out the accounting for an obligation to pay a levy that is not income tax. The interpretation addresses the accounting for a liability to pay a levy recognised in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, and the liability to pay a levy whose timing and amount is certain; it does not address the related asset or expense.

Entities are not required to apply IFRIC 21 to emissions trading schemes (application is optional), due to a scope exception in the guidance.

The interpretation is likely to result in later recognition of some liabilities, particularly in connection with levies that are triggered by circumstances on a specific date. IFRIC 21 is effective as of 1 January 2014 and applies retrospectively.

1.3 Transmission and distribution

Transmission and distribution activities in the power and utilities industry include the transmission of power and the transportation of water or gas, as well as the distribution of these resources. This part of the value chain is also dependent on significant capital investment in electric grid facilities and pipeline networks.

1.3.1 Fixed assets and components

Network assets, such as an electricity transmission system or a gas pipeline, comprise many separate components. A network must be broken down into its significant parts that have different useful lives. The determination of the number and breakdown of parts is specific to the entity's circumstances. A number of factors should be considered in this analysis: the cost of different parts; how the asset is split for operational purposes; physical location of the asset; and technical design considerations.

Many individual components might not be significant. A practical approach to identifying components is to consider the entity's mid- to long-term capital budget, which should identify significant capital expenditures and pinpoint major components of the network that will need replacement over the next few years. The entity's engineering staff should also be involved in identifying components based on repairs and maintenance schedules and planned major renovations or replacements.

Some network companies apply renewals accounting for expenditure related to their networks under national GAAP. Expenditure is fully expensed, and no depreciation is charged against the network assets. This accounting treatment is not acceptable under IFRS, because the normal fixed asset accounting and depreciation requirements apply. This might be a significant change for network companies and introduces some application challenges.

An entity with a history of expensing all current expenditure might struggle initially to reinstate what should have been capitalised and what should have been expensed. Materiality is a useful guide; if replacement costs are material to the asset, these costs should be capitalised where recognition criteria are met (that is, where costs can be reliably measured and future economic benefits are probable). First-time IFRS adopters can benefit from an exemption according to IFRS 1, *First-time Adoption of International Financial Reporting Standards*. This exemption allows entities to use a value that is not depreciated cost in accordance

with IAS 16, *Property, Plant and Equipment*, and IAS 23, *Borrowing Costs*, as deemed cost on transition to IFRS. It is not necessary to apply the exemption to all assets or to a group of assets.

Network companies might be accustomed to a working assumption that assets have an indefinite useful life. All significant assets have a finite life, to be determined under IAS 16, being the time remaining before the asset needs to be replaced. Maintenance and repair activities might extend this life, but ultimately the asset will need to be replaced.

A residual value must be determined for all significant components. In many cases, this value is likely to be scrap only or nil, because IAS 16 defines 'residual value' as the disposal proceeds if the asset were already of an age and in the condition expected at the end of its useful life. An entity is required to allocate costs at initial recognition to its significant parts. Each part is then depreciated separately over its useful life. Separate parts that have the same useful life and depreciation method can be grouped together to determine the depreciation charge.

1.3.2 Customer contributions

The provision of utility services to customers requires some form of physical connection, whether the service is gas, water or power. The investment required to provide that connection to the customer, from the national or regional network, might be significant. This is likely where the customer is located far from the network or where the volume of the utility that will be purchased requires substantial equipment. An example is the provision of power to a remote location where the construction of a substation is required to connect the user to the national network.

Many utility entities require the customer to contribute to the cost of the connection, and in return the customer receives the right to access the utility services. The utility entity constructs the connecting infrastructure and retains responsibility for maintaining it. The questions are how the utility accounts for the contribution of the customer, whether the assets contributed are recorded at cost or fair value, and whether the credit goes to income immediately or whether it has to be deferred over the life of the asset or the contractual right to use.

The diversity of accounting methods used by entities for the assets that they received led the Interpretation Committee of the IASB to issue IFRIC 18, *Transfers of Assets from Customers*. The interpretation requires the transferred assets to be recognised initially at fair value

and the related revenue to be recognised immediately; or, if there is a future service obligation, revenue is deferred and recognised over the relevant service period.

The entity should assess whether the transferred item meets the definition of an asset, as set out in the IFRS Framework. A key element is whether the entity has control of the item. The transfer of right of ownership is not sufficient for establishing control. All facts and circumstances should be analysed. An example is the ability of the entity to decide how the transferred asset is operated and maintained and when it is replaced. If the definition is met, the asset is measured at its fair value, which is its cost.

It is assumed that the entity has received the asset in exchange for the delivery of services. Examples are the connection to a network and/or providing ongoing access to a supply of goods or services. For each identifiable service within the agreement, revenue should be recognised as each service is delivered in accordance with IAS 18.

Where an entity provides both connection to a network and ongoing access to goods or services, management should determine whether these services are separate elements of the arrangement for the purposes of revenue recognition.

The accounting depends on facts and circumstances that differ from country to country. Management should consider the following features for determining whether the connection service is a separately identifiable service:

- The connection represents stand-alone value to the customer. If the network entity concludes that the connection service does not represent stand-alone value, it defers revenue over the period of the ongoing access service (or the life of the asset, if shorter).
- The fair value of the connection service is reliably measurable. If the fair value of the connection service cannot be measured reliably, revenue might be deferred and recognised over the period in which the ongoing access service is provided.

Features indicating that the ongoing access service might be a separately identifiable service are:

- The customer receives the ongoing access service or goods and services at a price that is lower than that for customers who have not transferred an asset. Where a customer pays a lower price in the future, revenue is recognised over the period in which the service is delivered (or the life of the asset, if shorter).

- Where a customer transferring assets to the entity pays the same price for goods or services as one that does not, management might determine that this indicates that the provision of ongoing access arises from the entity's operating licence or other regulation, rather than as a result of the asset transfer from the customer. If management determines that the ongoing access service does not arise from the transfer of the connection asset, it is only the connection service that is provided in exchange for the transfer of the asset, and revenue is recognised immediately.

Major connection expenditures, such as substations or network spurs, often benefit more than one customer, and contributions might be received from several of these. However, where major connection equipment is constructed for the sole benefit of one customer, consideration should be given to whether the equipment has effectively been leased to the customer. IFRIC 4 and IAS 17 should be applied to determine whether the arrangement is, in substance, a lease and whether it should be classified as an operating or finance lease.

1.3.3 Regulatory assets and liabilities

Complete liberalisation of utilities is not practical, because of the physical infrastructure required for the transmission and distribution of the commodity – a monopoly of the infrastructure's owner is created. Therefore, privatisation and the introduction of competition are often balanced by price regulation. Some utilities continue as monopoly suppliers, with prices limited to a version of cost plus margin overseen by the regulator.

The regulatory regime is often unique to each country. The two most common types of regulation are incentive-based regulation and cost-based regulation. The regulator governing an incentive-based regulatory regime usually sets the 'allowable revenues' for a period, with the intention of encouraging cost efficiency from the utility. A utility entity operating under cost-based regulation is typically permitted to recover an agreed level of operating costs, together with a return on assets employed.

An entity's accounting policies should consider the regulatory regime and the requirements of IFRS. Any asset or liability arising from regulation to be recognised under IFRS should be evaluated based on applicable IFRSs or the Framework, as there is no specific standard for the accounting for such assets or liabilities under IFRS.

IFRS 14 was issued in January 2014 as an interim standard on rate-regulated activities. IFRS 14 permits first-time adopters to continue to recognise amounts related to rate regulation in accordance with their previous GAAP accounting policies on adoption of IFRS. However, IFRS 14 requires the effect of rate regulation to be presented separately from other items to enhance comparability with entities that already apply IFRS (and therefore do not recognise such amounts). An entity that already presents IFRS financial statements is not eligible to apply the new guidance.

1.3.4 Line fill and cushion gas

Some items of property, plant and equipment (PPE), such as pipelines and gas storage, require a 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. The product is therefore recognised as a component of the PPE at cost, and is subject to depreciation to estimated residual value.

However, product owned by an entity that is stored in PPE owned by a third party continues to be classified as inventory. This includes, 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 first-in, first-out (FIFO) or weighted-average cost.

Example – Cushion gas

Entity A 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 entity A’s management account for the cushion gas as PPE or as inventory?

Entity A’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 paragraph 43 of IAS 16. However, if the cushion gas is recoverable in full when the storage facility is decommissioned, depreciation is 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 paragraph 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.

1.3.5 Net realisable value of gas inventories

Gas purchased for use by a utility is valued at the lower of cost and net realisable value if it will be used as a fuel.

Determining net realisable value 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 gas product using the market price at the balance sheet date.

Movements in the gas 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 net realisable value.

1.3.6 Network operation arrangements

Rights to use public ground for constructing and operating electricity grids are often limited in time. Municipalities might decide to not prolong these rights once they have expired, but operate the grids on their own or enter into co-operation agreements with network-operating companies or other municipalities. The arrangements might take various forms, such as:

- leasing the grid assets directly to network operating entities;
- establishing (together with a network operator) network-holding companies, which lease the grid assets out to the network operator; or
- joint arrangements with other municipalities or entities, which can comprise numerous collaboration and service contracts.

Usually the arrangements are rather complex, because they comprise a multitude of contracts between the parties, such as contracts regulating the rights and obligations between the shareholders of the network holding companies, lease contracts and service contracts. All entities involved in these arrangements have to analyse all facts and circumstances in order to conclude the appropriate accounting treatment. The contracts could also give rise to a concession service agreement, which is discussed in section 1.5.1.

1.4 Retail

Customer acquisition costs

Deregulation of markets and the introduction of competition often provide customers with the ability to switch from one supplier to another. Utility entities invest in winning and developing their relationships with their customers. The costs of acquiring and developing these customer relationships are capitalised as separately acquired intangible assets, if certain conditions are met. The costs directly attributable to concluding a contractual agreement with a customer are capitalised and amortised over the life of the contract. These costs include commissions or bonuses paid to sign the utility customers where the utility entity has the systems to separately record and assess the customer contract for future economic benefits. If customers have short-term notice periods (one month, for example), the asset usually cannot be controlled over an extended period of time and therefore is not capitalised.

Expenditure relating to the general development of the business (such as providing service in a new location or an advertising campaign for new customers) is not capitalised because it does not meet the asset recognition criteria. Such general expenditure is not capitalised because the specific costs associated with individual customers cannot be separately identified or because the entity has insufficient control over the new relationship for it to meet the definition of an asset.

However, customer relationships must be recognised when they are acquired through a business combination. Customer-related intangibles (such as customer lists, customer contracts and customer relationships) are recognised by the acquirer at fair value at the acquisition date.

1.5 Entity-wide issues

1.5.1 Service concession arrangements

Public/private partnerships are one method whereby governments attract private sector participation in the provision of infrastructure services. These services might include toll roads, prisons, hospitals, public transportation facilities, and water and power distribution. These types of arrangement are often described as 'concessions', and many fall within the scope of IFRIC 12, *Service Concession Arrangements*. Arrangements within the scope of the standard are those where a private sector entity might construct the infrastructure, maintain and provide the service to the public. The provider might be paid for its services in different ways. Many concessions require the related infrastructure assets to be returned or transferred to the government at the end of the concession.

IFRIC 12 applies to arrangements where the grantor (that is, the government or its agent) controls or regulates what services the operator provides with the infrastructure, to whom it must provide them and at what price. The grantor also controls any significant residual interest in the infrastructure at the end of the term of the arrangement.

Water distribution facilities and energy supply networks are examples of infrastructure that might be the subject of service concession arrangements. For example, the government might have authorised the building of a new town. It might grant a concession to a power distribution entity to construct the distribution network, maintain it and operate it for a period of 25 years. The distribution network is transferred to the government at the end of the concession period, with a specified level of functionality for no consideration. The national regulator sets prices on a cost-plus basis. The concession arrangement has baseline service commitments that trigger substantial penalties if service is interrupted. The government requires the power entity to provide universal access to the electricity network for all residents of the town.

This arrangement would fall within the scope of IFRIC 12, because it has many of the common features of a service concession arrangement, including:

- The grantor of the service arrangement is a public sector entity or a private sector entity to which the responsibility for the service is delegated (in this case, the government has authorised the new town and granted the licence).

- The operator is not an agent acting on behalf of the grantor, but is responsible for at least some of the management of the infrastructure (the operator has an obligation to maintain the network).
- The arrangement is governed by a contract (or by the local law, as applicable) that sets out performance standards, mechanisms for adjusting prices and arrangements for arbitrating disputes (there are financial penalties for poor operating performance and cost-plus tariff).
- The operator is obliged to hand over the infrastructure to the grantor in a specified condition at the end of the period of the arrangement (transfer with no consideration from the government at the end of the concession period).

The two accounting models under IFRIC 12 that an operator applies to recognise the rights received under a service concession arrangement are:

- Financial asset – An operator with a contractual and unconditional right to receive specified or determinable amounts of cash (or other financial assets) from the grantor recognises a financial asset. The financial asset is within the scope of IAS 32, *Financial Instruments: Presentation*, IAS 39 and IFRS 7, *Financial Instruments: Disclosures*.
- Intangible asset – An operator with a right to charge the users of the public service recognises an intangible asset. There is no contractual right to receive cash when payments are contingent on usage. The licence is within the scope of IAS 38.

Arrangements between governments and service providers are complex, and the conclusions are seldom as obvious as the example above. Detailed analysis of the specific arrangement is necessary to determine whether it is in the scope of IFRIC 12 and whether the ‘financial asset’ or ‘intangible asset’ model should be applied. Some complex arrangements might have elements of both models for the different phases, so it might be appropriate to account separately for each element of the consideration.

1.5.2 Business combinations

Acquisitions of assets and businesses are common in the utility industry. These might be business combinations or acquisitions of groups of assets. IFRS 3, *Business Combinations*, provides guidance on both types of transaction, and the accounting can differ significantly.

Typical accounting issues for 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.
- Two options for the measurement of any non-controlling interest (previously minority interest) on a combination-by-combination basis – fair value or proportion of net asset value.

Issues commonly encountered in the utility industry include making the judgement about whether a transaction is a business combination or an asset acquisition. The distinction is likely to have a significant impact on the recognition and valuation of intangible assets, goodwill and deferred tax. IFRS 3 has expanded the scope of what is considered to be a business, and guidance continues to evolve. However, more transactions are business combinations under IFRS 3 than were considered such under the previous standard.

IFRS 3 amended the definition of a ‘business’ and provided further implementation guidance. 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.

Integrated utilities typically represent a business, as a number of assets, and additional processes exist to manage that portfolio.

Example – Power plant acquisition

The sale or acquisition of a power plant might consist of the entire plant operation, including contracts, employees and support services. Such a transaction would involve an integrated set of activities and would meet the definition of a business.

However, a question might arise in evaluating whether the acquisition of a power plant without the related contracts and employees meets the definition of a business. The acquisition of a power plant generally involves obtaining inputs (that is, the power plant) and some processes (such as the

workforce or technical know-how). In evaluating a typical power plant, a market participant is able to acquire fuel, the requisite workforce and applicable technical knowledge, either by integrating the acquired group with its own inputs and processes (for example, if the acquirer already manages generation facilities) or by engaging service providers for operations and maintenance and administrative services. By doing so, a power and utilities entity would be able to operate the facility to create outputs. It is rare that the acquisition of a power plant would not be a business combination.

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 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*.

Acquisition of an integrated utility or a group of generators located in a single country falls squarely into the scope of IFRS 3 as a business combination; the classification of the acquisition of a single pipeline, or a portion of a transmission network, might not be so clear cut.

IFRS 3 requires the acquisition method of accounting to be applied to all business combinations. The acquisition method comprises the following steps:

- Identify the acquirer and determine the acquisition date.
- Recognise and measure the consideration transferred for the acquiree.
- Recognise and measure the identifiable assets acquired and liabilities assumed, including any non-controlling interest.
- Recognise and measure goodwill or a gain from a bargain purchase.

These aspects of the business combination are not unique to the utility industry. Please refer to PwC's publication 'A Global Guide to Accounting for Business Combinations and Noncontrolling Interests' for further guidance on these issues.

A number of common industry-specific issues do arise when recognising and measuring the identifiable assets and liabilities of an acquired utility. These include:

- A utility might have a brand name and a logo. The fair value of the intangible assets could be significant in a market with customer choice, but less so in a monopoly market.
- A transmission network might be a separate business that holds relationships with a number of generators and distribution companies. These customer relationships could have value, but less so in a monopoly market.
- Existing contracts and arrangements might give rise to assets or liabilities for above or below market pricing. This could include operating leases, fuel purchase arrangements, and contracts that qualify for own use that might otherwise be derivatives under IAS 39.
- The utility usually has a licence or a series of licences to operate. In practice, these licences are almost always embedded into the value of the fixed assets, as the two can seldom be separated. For example, a licence to operate a nuclear power plant is specific to the location, assets and often the operator (and is not freely transferable). The licence and fixed assets are usually valued on the basis of expected cash flows, and they incorporate any existing rate agreements that survive the business combination.
- A utility might have a right to develop and construct a wind farm on a specified area of land or sea or to repower an existing wind farm. These rights might have value as intangible assets in a business combination.

1.5.3 Joint arrangements

Joint arrangements are frequently used by power and utilities companies as a way to share risks and costs, or as a way of bringing in specialist skills to a particular project. The legal basis for a joint arrangement can take various forms: a joint arrangement might be established through a formal 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.

Joint control

IFRS 11 defines 'joint control' as:

'the contractually agreed sharing of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.'

For many investees, a range of operating and financing activities significantly affect their returns. Examples of decisions about relevant activities in the power and utilities industry include:

- establishing operating and capital decisions of the investee about running a power plant, including budgets; and
- appointing and remunerating an investee's key management personnel or service providers and terminating their services or employment.

The assessment of joint control focuses on whether the investors (or a specific sub-set of investors) must agree on all decisions over relevant activities.

Consideration of joint control would consist of, but not be limited to, the following:

- the composition of the Board (or other decision-making body);
- whether each Board member's vote is required to align with the interest of the shareholder represented;
- ability to change Board members once appointed; and
- how disputes are resolved.

Joint control might be present even if one of the investors acts as operator of the joint arrangement.

The operator's powers are usually limited to day-to-day operational decisions; key strategic financial and operating decisions (that is, decisions about the significant relevant activities) remain with the joint arrangement investors as a group, with unanimous consent required.

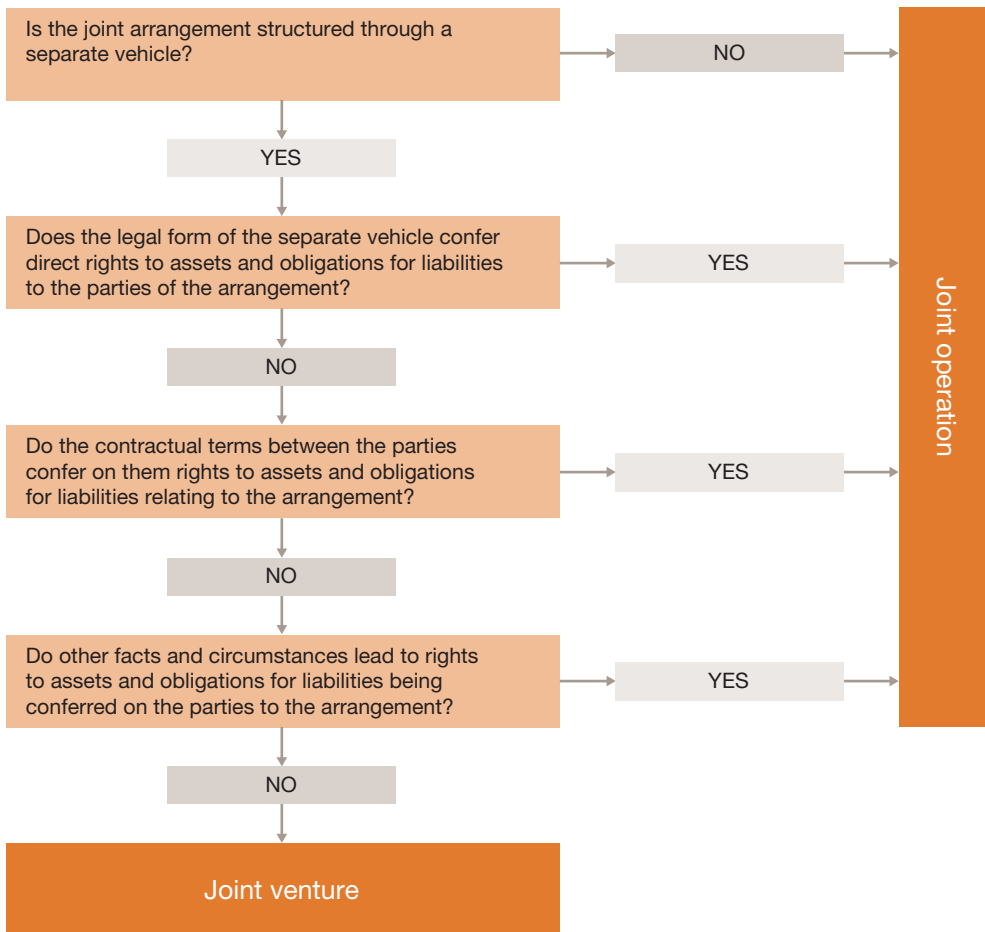
In contrast, joint control might not be present even if an arrangement is described as a 'joint venture'. Financial and operating decisions that are made by 'simple majority' rather than by unanimous consent could mean that joint control is not present, even in situations where two parties hold the majority of shares (for example, three parties to an arrangement with holdings of 45%, 45% and 10% respectively).

Classification of joint arrangements

The classification of the joint arrangement is based on the rights and obligations of the parties to the arrangement. Determination of the type of joint arrangement can be a complex decision under IFRS 11.

Determining the classification of a joint arrangement is a four-step process, as shown below.

In summary, 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 investors.



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. There are many different types of vehicle used for joint arrangements, including partnerships, unincorporated entities, limited companies and unlimited liability companies. Local laws and regulations also need consideration before determining whether a particular structure meets the definition of a 'separate vehicle'.

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 investors' rights and obligations relating to the arrangement.

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

- rights to the assets and obligations for the liabilities relating to the arrangement (that is, joint operation); or
- rights to net assets of the arrangement (that is, joint venture).

Local laws and regulations play a key role in the assessment of the rights and obligations conferred by the separate vehicle. It is possible that the same legal form in different territories could give different rights and obligations, depending on the local laws and regulations (for example, general partnerships).

Rights to assets and obligations for liabilities given by contractual terms

In most cases, the rights and obligations agreed to by the investors in their contractual terms are consistent with the rights and obligations conferred on the investors by the legal form of the separate vehicle. This is because the selection of a particular legal form is, in many cases, driven by the intended economic substance that the particular legal form delivers.

However, investors might choose a particular legal form to respond to tax consequences, regulatory requirements or for other reasons. This can alter the intended economic substance initially sought by the investors to the arrangement. In such cases, the

investors might enter into contractual arrangements that modify the effects that the legal form of the arrangement would otherwise have on their rights and obligations.

In addition, the local law of a territory might require an arrangement in a particular industry to be set up only in a limited liability company. This means that the legal structure of the separate vehicle will create a separation between the investors and the arrangement. However, the investors might have the intention of setting up a joint operation.

In such cases, the investors could enter into contractual terms which modify or reverse the rights and obligations conferred by the legal form of the separate vehicle. The contractual terms of the arrangement might be such that each investor has an interest in the assets of the company, and each investor has an obligation for the liabilities of the company in a specified proportion.

The contractual terms have to be assessed carefully to ensure that they are, in fact, robust enough to modify or reverse the rights and obligations conferred by the legal structure.

Effect of guarantees on classification of a joint arrangement

Investors in joint arrangements often provide guarantees to third parties on behalf of the arrangement where the arrangement is purchasing goods, receiving services or obtaining financing.

The question that commonly arises is whether provision of such guarantees (or commitment by the investors to pay in case the arrangement fails to pay or meet its obligations) indicates that the investors have obligations for liabilities of the arrangement and so the arrangement is a joint operation.

All relevant facts and circumstances should be considered in determining the classification. Rights and obligations 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 investors will be obligated to settle those liabilities because of the guarantee issued. This would not be seen as a normal course of business. Therefore, issuing a guarantee does not, on its own, mean that the arrangement is a joint operation.

‘Other facts and circumstances’

This is the final step in determining the classification of a joint arrangement. Where arrangements are incorporated in limited liability companies, classifying them as joint operations on the basis of ‘other facts and circumstances’ is considered a high hurdle to cross.

If the arrangement was primarily designed to provide output to the investors, it might indicate that the investors’ objective was to have rights to substantially all of the economic benefits of the arrangement’s assets.

The effect of an arrangement with such a design is that the liabilities incurred by the arrangement are, in substance, satisfied by the cash flows received from the investors through their purchases of the output. It also means that the investors are effectively the only source of cash flows for the continuity of the arrangement’s operations. This indicates that the investors have an obligation for the liabilities relating to the arrangement.

This type of design must be supported by contractual terms that bind the investors. This is generally achieved by a formal agreement between the investors requiring each to take their proportionate share of output and/or preventing the arrangement from selling to third parties. An arrangement that provides the investors with the right, but not the obligation, to take all of the output would not be viewed as joint operation; this is because the investors would not have a direct obligation.

‘Other facts and circumstances’ scenarios

Each of the scenarios considered on pages 31 and 32 has the following assumptions:

- joint control exists in each of the arrangements; and
- the arrangement is contained in a separate vehicle; the legal structure of the separate vehicle and the contractual terms do not give the investors rights to assets and obligations for liabilities.

The initial indicators are that the arrangements are joint ventures; however, the ‘other facts and circumstances’ are analysed as to how they might affect the classification of the arrangement.

Scenario	Classification	Analysis
<p>The arrangement (an offshore wind park located in the UK) produces two products – electricity and renewable energy certificates (RECs).</p> <p>100% of the power generated is taken by one party, and 100% of the RECs 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 proportion to their shareholding.</p>	<p>Depends on the contractual terms over output.</p>	<p>The parties do not need to set up a joint arrangement for an interest in the same product. They might have an interest in different products, but might set up a joint arrangement for reasons such as cost savings or similar manufacturing processes.</p> <p>In this case, the facts suggest that one party has operations in physical proximity to the wind farm, enabling that party to take 100% of the power directly. The other party takes 100% of the RECs, resulting in all of the output of the wind farm being consumed by the investors of the arrangement. As such, the arrangement appears dependent on the parties for cash flows (that is, the parties ‘fund operations’ through their purchase of the output). A contractual requirement for the parties to take substantially all of the output would result in classification as a ‘joint operation’; the lack of such requirement would likely result in ‘joint venture’ classification.</p>
<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 different ratio 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.

Scenario	Classification	Analysis
<p>Parties have a contractual agreement to take all of the output in proportion to their ownership interest. The arrangement is prohibited from selling output to third parties.</p> <p>All output must be purchased at cost plus a defined margin.</p>	Likely to be a joint operation.	The binding commitment of the parties to take all of the output provides the parties with the rights to the economic benefits of the assets and creates an obligation for the liabilities. The agreement means that the investors are substantially the only source of cash flows for the operations to continue.
<p>Two parties set up an arrangement to construct and operate a power plant. The power generated is sold to third parties.</p> <p>As per the contractual terms:</p> <ul style="list-style-type: none"> a) all of the gross cash proceeds from revenue of the arrangement are transferred to the parties on a monthly basis in proportion to their shareholding; and b) the parties agree to reimburse the arrangement for all its costs in proportion to their shareholding. 	Likely to be a joint venture.	<p>In this case, it is clear that the arrangement is not designed to provide all of its output to the parties.</p> <p>The arrangement is selling the product to third parties and is generating its own cash flows.</p> <p>The transfer of gross proceeds of revenues to the parties, and reimbursement for costs incurred, do 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>

Reassessment of classification

The rights and obligations of parties to joint arrangements might change over time. Consequently, the assessment of the type of joint arrangement needs to be a continuous process, to the extent that facts and circumstances change.

Accounting for joint operations

Investors in joint operations 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; and
- its expenses, including its share of any expenses incurred jointly.

‘Share of assets and liabilities’ is not necessarily 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.

Accounting for joint ventures (‘JVs’)

IFRS 11 requires equity accounting for all joint arrangements classified as joint ventures.

The key principles of the equity method of accounting are described in IAS 28 as follows:

- 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 (that is, using the same GAAP (IFRS) and the same accounting policy choices). The growing use of IFRS and convergence with US GAAP have helped in this regard, but the basis of accounting should be set out in the formation documents of the joint venture.

Example – Joint venture uses a different GAAP

An entity 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 venturers, 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 entity J can be used.

Must entity 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. IAS 28 requires all information contained in IFRS financial statements to be prepared according to IFRS. Entity C’s management must therefore make appropriate adjustments to entity J’s US GAAP results to make them compliant with IFRS requirements. There is no exemption in IFRS for impracticability.

The same requirement would exist if entity J was a joint operation. Adjustments to conform accounting policies are also required where both entities use IFRS.

Contributions to joint arrangements

It is common for participants to 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. Accordingly, the contributor should recognise a gain or loss on the partial disposal.

However, there is an inconsistency between IAS 28 and IFRS 10 relating to gain or loss recognition where the contribution to the joint venture is considered to represent a business.

IAS 28 requires the participant to recognise the gain or loss on the contribution, up to the share of the other investors in the arrangement.

In contrast, IFRS 10 states that any investment that 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 full in profit or loss.

In October 2013, the IASB finalised amendments to IFRS 10 and IAS 28 which would result in full gain or loss recognition where a business (as defined in IFRS 3) is contributed to a joint venture. Partial gain or loss recognition would be applied for the contribution of assets that do not constitute a business. The amendments will not address similar contributions to joint operations. As of the date of this publication, the final amendments are expected to be issued in Q2 2014 and to be effective as of 1 January 2016.

Investments with less than joint control

Public/private partnerships are one method whereby Some co-operative arrangements might appear to be joint arrangements but fail on the basis that unanimous agreement between investors over relevant activities is not required. This might arise where a super majority (for example, 80%) is required but the threshold can be achieved with a variety of combinations of shareholders and no sub-set of investors are able to make all decisions together. Accounting for these arrangements will depend on the way in which they are structured and the rights of each investor.

If an entity does not qualify as a joint arrangement, 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 might also participate in a joint operation but not have joint control. The investor should account for its rights to assets and obligations for liabilities. If it does not have rights to assets or obligations for liabilities, it should account for its interest in accordance with the IFRS applicable to that interest.

Investors might also 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 operating capacity of that asset. An example is where a number of investors have invested in a shared road network, and an investor with a 20% interest has the right to use the network. Industry practice is for an

Example – Identifying a joint venture

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

Background

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

Entity A's management wants to account for its interest in entity J using share of revenue and assets in its IFRS consolidated financial statements, because entity J is a joint operation. Can entity A's management account for entity J in this way?

Solution

No, entity A cannot account for entity J using share of revenue and assets, because entity J is not jointly controlled. The voting arrangements would require unanimous agreement between those sharing the joint control of entity J to qualify as a joint arrangement. The voting arrangements of entity J allow agreement of any combination of three of the four partners to make decisions (typically referred to as 'collective control').

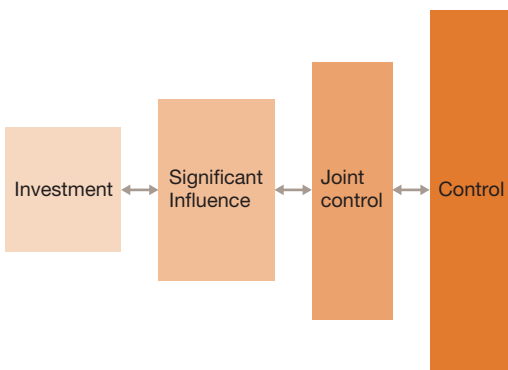
Each investor must therefore account for its interest in entity J as an associate, since they each have significant influence but they do not have joint control. Equity accounting must therefore be applied.

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 they should be classified in the same way as equivalent costs for wholly owned assets.

Changes in ownership in a joint arrangement

A participant in a joint arrangement can 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.



1.5.4 Consolidation

The IASB published IFRS 10, *Consolidated Financial Statements*, and IFRS 12, *Disclosure of Interests in Other Entities*, in May 2011. The standards replace IAS 27, *Consolidated and Separate Financial Statements* (which is amended to become IAS 27, *Separate Financial Statements*). The standards are effective for 2013, except in the EU countries where they have been endorsed with an effective date of 2014. Early adoption is permitted where these standards (together with IFRS 11 and consequential amendments to IAS 28) are adopted at the same time.

This section focuses on the changes introduced by IFRS 10. The mechanics of consolidation are unchanged by the new standard and, because those mechanics are generic, they are not detailed further here. Instead, this section focuses on the new definition and guidance with regard to 'control'; changes introduced by IFRS 11 on joint control and joint arrangements have been separately examined in section 1.5.3.

Control

IFRS 10 confirms that consolidation is required where control exists. The standard defines 'control' in the following terms: where an investor has power to direct relevant activities, exposure to variable returns, and the ability to use its power to affect its returns. Previously, control through voting rights was addressed by IAS 27, while exposure to variable returns was an important consideration within the SIC 12 framework. However, the relationship between these two approaches to control was not always clear. IFRS 10 links power and returns by introducing an additional requirement that the investor is capable of using that power to influence its returns.

Key factors to be assessed by power and utilities entities, to determine control under the new standard, 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.

Purpose and design of an investee

The purpose and design of an investee could impact the assessment of what the relevant activities are, how those activities are decided, who can direct those activities, and who can receive returns from those activities. The consideration of purpose and design might make it clear that the entity is controlled by voting rights or potential voting rights. Voting rights in some cases might not significantly impact an investee's return. The investee might be on 'auto-pilot' through contractual arrangements. In those cases, the following should be considered in assessing the purpose and design of an entity:

- a) downside risks and upside potential that the investee was designed to create;
- b) downside risks and upside potential that the investee was designed to pass on to other parties in the transaction; and
- c) whether the investor is exposed to those risks and upside potential.

Substantive or protective rights

Only substantive rights are considered in the assessment of power; protective rights (that is, rights designed only to protect an investor's interest without giving power over the entity and which can only be exercised under specified conditions) are not relevant in the determination of control.

Potential voting rights

Potential voting rights are defined as '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 only presently exercisable rights were considered in the determination of control.

Principal or agent

The 'principal vs. agent' determination is also important. Parties in power plant arrangements will often be appointed to operate the project on behalf of the investors. A principal might delegate some of its decision authority to the agent, but the agent would not be viewed as having control where it exercises such powers on behalf of the principal.

Relationships between investors and how they affect control

Economic dependence in an arrangement, such as a coal-fired power plant which relies on coal to be mined 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.

Example – Can an option provide power if it is out of the money?

Investors X and Y hold 30% and 70% respectively of a company ('investee') that is controlled by voting rights. X has a currently exercisable, out-of-the-money call option over the shares held by Y. Can the option provide X with power over the investee?

Solution

Yes, such an option can provide X with power if it is determined to be substantive. This will require judgement based on all of the facts and

circumstances: X must benefit from the exercise of the option in order for it to be substantive. The option is out of the money, which might indicate that the potential voting rights are not substantive. However, X might benefit from exercising the option, even though it is out of the money. X might achieve other benefits – such as synergies or the elimination of a competitor – and might, overall, benefit from exercising the option. The option is likely to be substantive in those circumstances.

De facto control

This is one of the significant changes introduced by IFRS 10 - the standard includes guidance on de facto control for the first time. An investor with less than a majority of the voting rights might hold the largest block of voting rights, with the remaining voting rights widely dispersed. The investor might have the power to unilaterally direct the investee unless a sufficient number of the remaining dispersed investors act in concert to oppose the influential investor. However, such concerted action might be hard to organise if it requires the collective action of a large number of unrelated investors.

Structured entities

Voting rights might not have a significant effect on an investee's returns. For example, voting rights might relate to administrative tasks only, and contractual arrangements dictate how the investee should carry out its activities. These entities are described as 'structured entities'. Previously, SIC 12 used the term 'special purpose entities' (SPEs) to mean those entities that are created to accomplish a narrow and well-defined objective, and it stipulated separate consolidation criteria for these entities. This term is no longer used under IFRS 10. However, a narrow and well-defined objective might be an identification characteristic for structured entities. This suggests that a subset of former SPEs might qualify to be classified as 'structured entities'. 'Auto-pilot' entities under SIC 12 are a key candidate for classification as 'structured entities'. All substantive powers in such entities might appear to have been surrendered to contracts that impose rigid control over the entities' activities. None of the parties might appear to have power. However, entities might be indirectly controlled by one of the parties involved. Further analysis is required to determine if there is a party with control.

De facto agent

An agent need not be bound to the principal by a contract. IFRS 10 uses the term 'de facto agents' to describe agents who might be acting on behalf of principals even where there is no contractual arrangement in place. Identification of such relationships is expected to be highly judgemental.

Consideration should be given to the nature of relationships between the investor and various parties, and how they interact with each other.

The standard identifies a number of possible de facto agent/principal relationships, including:

- IAS 24 related parties of the principal;
- parties that received interests in the investee as a contribution or loan from the principal;
- parties that agreed not to sell, transfer or encumber their interests in the investee without the principal's approval;
- parties that cannot finance operations without subordinated financial support from the principal;
- parties that have largely similar governing body members or key management personnel as the principal; and
- parties that have close business relationships with the principal.

An investor with a de facto agent should consider the de facto agent's decision-making rights, as well as its indirect exposure to variable returns through the de facto agent, when assessing control of the investee.

Frequency of reassessment

Reassessment of control is required if facts and circumstances indicate changes to the elements of control. IFRS 10 highlights that control can change where:

- decision-making mechanisms change (for example, change from a substantive voting system to an ‘auto-pilot’ mechanism);
- events occur, even if they do not involve the investor (for example, lapse of decision-making rights by another party);
- an investor’s exposure or rights to variable returns change; and
- the relationship between an agent and a principal changes.

However, a change in market conditions on its own will not result in a reassessment of control, unless it changes one of the three elements of control.

2 *Financial instruments*

2 *Financial instruments*

2.1 *Overview*

The accounting for financial instruments can have a major impact on the financial statements of a power and utilities entity. Many utilities 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 instrument issues arise through both the scope of IAS 39 and the rules around accounting for embedded derivatives. Many entities that are engaged in the generation, transmission and distribution of electricity might be party to commercial contracts that are within the scope of IAS 39. Other entities might have active energy trading programmes that go far beyond mitigation of risk. This section looks at the accounting issues associated with two broad categories of financial instruments: those that might arise from the scope of IAS 39; and those that arise from active trading and treasury management activity. It also addresses accounting for weather derivatives.

2.2 *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 and are subject to fair value accounting, unless the 'own use' exemption applies. Contracts within the scope of IAS 39 are treated as derivatives and are marked to market through the income statement, unless management can and does elect cash flow hedge accounting.

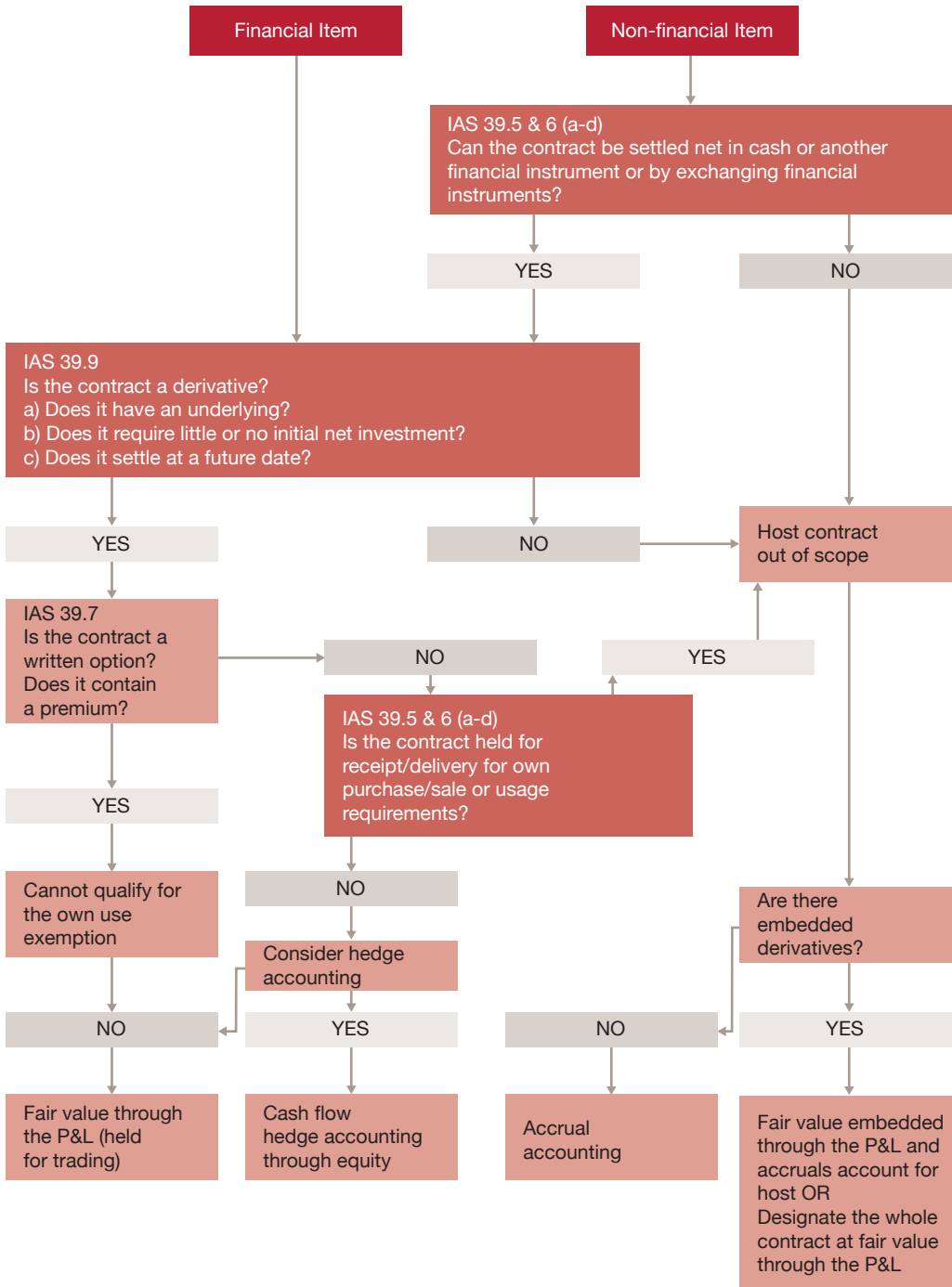
The 'net settlement' notion in IAS 39 is quite broad.

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

- a) The terms of the contract permit either party to settle it net in cash or another financial instrument.
- b) The entity has a practice of settling similar contracts net, whether:
 - with the counterparty;
 - by entering into offsetting contracts; or
 - by selling the contract before its exercise or lapse.
- c) The entity has a practice, for similar items, of taking delivery of the underlying and selling it within a short period after delivery for the purpose of generating a profit from short-term fluctuations in price or a dealer's margin.
- d) The commodity that is the subject of the contract is readily convertible to cash.

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

Commodity contracts decision tree (IAS 39)



2.3 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 in accordance with the entity’s expected purchase, sale or usage requirements. In other words, the contract results in physical delivery of the commodity. Own use is not an election. A contract that meets the own use criteria cannot be selectively measured at fair value, unless it otherwise falls into the scope of IAS 39 (for example, by applying the fair value option election to a contract if it contains an embedded derivative). Own use contracts cannot be designated as a financial asset or financial liability at fair value through profit or loss, because they are not financial instruments in the scope of IAS 39.

The practice of settling similar contracts net prevents an entire category of contracts from qualifying for the own use treatment (that is, all similar contracts must then be recognised as derivatives at fair value). If the entity has a practice of settling similar contracts net, or 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 a dealer’s margin, the contract cannot qualify for own use treatment. These contracts must be accounted for as derivatives at fair value.

If the terms of the contracts permit either party to settle them net in cash or another financial instrument, or the commodity that is the subject of the contracts is readily convertible to cash, the contracts are evaluated to see if they qualify for own use treatment. There are active markets for many commodities, such as oil, gas and electricity, and such contracts would meet the ‘readily convertible to cash’ criterion. An active market exists where prices are publicly available on a regular basis with sufficient liquidity, 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 is applicable. An entity’s policies, procedures and internal controls are therefore critical in determining the appropriate treatment of its commodity contracts.

Own use – Example 1

A utility enters into a sales contract with an industrial customer for delivery of 500 MWh of electricity for a fixed price in 2012. Management concludes that all criteria for own use are met, and therefore the utility accounts for the contracts as an own use executory contract. After signing the contract, but before delivery, the industrial customer decides to restructure its business, and its expected consumption declines to only 300 MWh in 2012.

Based on the expected change in consumption, the customer exercises an option under the contract to take a volume of only 300 MWh; and, as compensation, the utility is paid the difference between the contract price and the actual forward price for 200 MWh. The 300 MWh are still expected to be delivered to the customer. The contract fails to meet own use at the time of exercising the option and has to be accounted for as a derivative in accordance with IAS 39, because the contract was settled net.

Own use – Example 2

Entity A, the buyer, is engaged in power generation, and entity B, the seller, produces natural gas. Entity A has entered into a 10-year contract with entity B for the purchase of natural gas.

Entity A extends an advance of C1 billion to entity B, which is the equivalent of the total quantity contracted for 10 years at the rate of C4.5 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, on 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?

The own use criteria are met. There is an embedded derivative (being the price adjustment mechanism) but it does not require separation.

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 meets the condition in paragraph 6(a) of IAS 39. The expected frequency/intention to pay a penalty rather than deliver does not matter, because 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 is considered net settled.

However, the contract still qualifies 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, the contract is to be regarded as a written option. A written option is not entered into for own use.

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

2.4 Measurement of long-term contracts that do not qualify for 'own use'

Long-term commodity contracts are not uncommon, particularly for the purchase of fuel and sale of power and gas. Some of these contracts might be within the scope of IAS 39 if they contain net settlement provisions and/ or do not qualify for own use treatment. Due to the long duration of such contracts, it might be more difficult to prove the intention to hold such contracts for an entity's purchase, sale or usage requirements over the full lifetime of the contract. In such cases, these contracts are measured at fair value using the guidance in IAS 39, with changes recorded in the income statement. Market prices might not be available for the entire period of the contract. For example, prices might be available for the next three years, and then some prices for specific dates further in the future. This is described as having illiquid periods in the contract. These contracts are valued using valuation techniques.

Contracts for commodities with underlyings that are not readily convertible to cash (that is, for which no active market exists, such as gas in certain markets or gas capacity) mostly do not meet the definition of a 'derivative', and so they are accounted for as executory contracts; although the other criteria in paragraph 6 of IAS 39 also need to be tested, they will apply only rarely.

Valuation can be complex, and valuation techniques are intended to establish what the transaction price would have been on the measurement date in an arm's length exchange motivated by normal business considerations. Therefore, valuation techniques should:

- a) incorporate all factors that market participants would consider in setting a price, making maximum use of market inputs and relying as little as possible on entity-specific inputs;
- b) be consistent with accepted economic methodologies for pricing financial instruments; and
- c) be tested for validity using prices from any observable current market transactions in the same instrument or based on any available observable market data.

This is an area where transparent disclosure of the policy and approach, including significant assumptions, is crucial, to ensure that users understand the entity's financial statements. Under IFRS 7, the valuations of such long-term contracts generally fall in level 3 of the fair value hierarchy. The disclosures for level 3 are extensive and include reconciliations from the beginning and ending balances that have recognised gains and losses in profit and loss, total gains and losses in comprehensive income, as well as purchases, sales, issues and settlements. [IFRS 7 para 27B]. Also, if changes of valuation inputs to other possible alternative assumptions would change the fair value of the contract, the effects need to be disclosed.

Day One profits or losses

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 profits or losses.

The contracts are initially recognised under IAS 39 at fair value. Any such Day One profit gains or losses can be recognised only if the fair value of the contract is either:

- 1) evidenced by other observable market transactions in the same instrument; or
- 2) Based on valuation techniques whose variables include only data from observable markets.

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

Any Day One profit or loss that is not recognised initially 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. Generally, utilities recognise the deferred profit/loss in the income statement on a systematic basis as the volumes are delivered or as observable market prices become available for the remaining delivery period.

2.5 Take-or-pay contracts and volume flexibility (optionality)

Take-or-pay contracts

Generators can enter into long-term take-or-pay contracts with fuel suppliers. These arrangements give rise to an obligation for the generator to purchase a minimum quantity or value of the relevant fuel. The actual quantity or value of fuel that the generator requires might be less than the minimum agreed amount in any measurement period. The generator might be required to pay to the supplier the equivalent

monetary value of the shortfall, or the shortfall amount might also be carried forward and used in satisfaction of supply in subsequent periods.

A long-term take-or-pay contract might not fall within the scope of IAS 39 because of inherent variability in amount and/or because the ability to 'net settle' might preclude 'own use'. In most cases, however, a payment of the contractual amount for the volume that was not taken is not considered a net settlement, because there is no payment based on the difference between contract price and market price.

Example

A utility enters into a fixed-price gas sales contract with an industrial customer for the years 2011 to 2013. The expected gas quantity to be delivered is determined, but the customer has the right to take between 95% and 105% of the determined quantity at the same fixed price. If the customer consumes less than 95%, it has to pay the price for 95% (take-or-pay volume). The utility operates in a local gas market which is not liquid, and so it does not record a derivative under IAS 39 (no net settlement). In 2011 the customer consumes only 80% of the determined quantity. The utility charges the

customer the fixed price for 95% of the determined quantity, which results in cash settlement for the quantity of 15% not delivered.

The payment of the total amount (fixed price) for the non-delivered quantity does not constitute a net settlement, because there is no payment between the parties for the net amount calculated as the difference between contract price and market price. As such, a contract with these terms would not be accounted for as a derivative.

Volume flexibility (optionality)

Contracts for the supply of commodities might give the buyer the right to take either a minimum quantity or any amount based on the buyer's requirements. A minimum annual commitment does not create a derivative for the purchaser, as long as the entity expects to purchase all of the guaranteed volume for its own use.

A derivative or an embedded derivative might arise if it becomes likely that the entity will not take the commodity, and will instead pay a penalty under the contract based on the market value of the commodity or some other variable. Since physical delivery is no longer probable, the derivative would be recorded at the amount of the penalty payable. Changes in market price will affect the penalty's carrying value until the penalty is paid.

A penalty payable that is fixed or predetermined does not give rise to a derivative, because the penalty's value remains fixed irrespective of changes in the product's market value. The entity will need to provide for the penalty payable, however, once it becomes clear that non-performance is likely.

A contract will fail the own use exemption if the quantity specified in the contract is more than the entity's normal usage requirement and the entity intends to net settle part of the contract that it does not need in the normal course of business. The entity could take all of the quantities specified in the contract and sell the excess, or it could enter into an offsetting contract for the excess quantity. The entire contract in these situations falls within IAS 39's scope and should be marked to market.

The supplier of the commodity can look at the volume flexibility feature in the contract in two ways. The first is to view the contract as a whole. The contract includes a written option for the element of volume flexibility. The whole contract should be viewed as one instrument and, if the item being supplied (electricity) is readily convertible to cash, paragraph 7 of IAS 39 prevents the supplier from classifying the contract as own use. This states that a written option on a non-financial item that is readily convertible to cash cannot be entered into for the purpose of the receipt or delivery of a non-financial item in accordance with the entity's expected purchase, sale or usage requirements.

A second view is that the contract has two components: an own use fixed volume host contract, outside IAS 39's scope for any contractually fixed volume element; and an embedded written option within IAS 39's scope for the volume flexibility element. The latter would be in IAS 39's scope if the item being supplied (electricity) is readily convertible to cash, for the same reason as under the first view.

The IFRIC discussed the issue of volume flexibility in March 2010 and recognised that significant diversity exists in practice with respect to volumetric optionality. However, IFRIC decided not to add the issue to its agenda because of the Board's project to develop a replacement for IAS 39.

Volume flexibility exists within a contract where the buyer contractually has the right (but not the obligation) to take volumes of the commodity within a volume range at a specified (often fixed) price. Within that range, the actual volume to be supplied is not fixed at the inception of the contract, but it is notified by the buyer during the course of the contract, thereby resulting in unpredictability in actual volumes for the supplier. In most cases, a higher price is charged for the commodity for entering into these contracts to compensate the supplier for the capacity, storage and other costs arising, due to the additional volume flexibility offered to the purchaser.

In accounting for such contracts, the reporting entity should first analyse whether it has a written option or a purchased option. Where the buyer has the right to choose the volume of the commodity purchased, the buyer has a purchased option and the supplier a written option.

Next it is necessary to determine whether the option can be settled net in cash or another financial asset. A written option to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, is within the scope of IAS 39. Such a contract cannot 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. [IAS 39 para 7].

In March 2007, the International Financial Reporting Interpretations Committee (IFRIC) received a request (that was primarily concerned with the accounting for energy supply contracts to retail customers) to interpret what is meant by 'written option' within the context of paragraph 7 of IAS 39. The IFRIC rejected the request, explaining that analysis of such contracts suggests that, in many situations, these contracts are not capable of net cash settlement as laid out in paragraphs 5 and 6 of IAS 39. Such contracts would not be considered to be within the scope of IAS 39.

Both qualitative and quantitative tests should be used to determine whether a contract with volume flexibility contains a written option that can be settled net in cash or another financial instrument.

Qualitative tests

- Does the purchaser have the ability to monetise the option?
- Does the purchaser have a choice in deciding whether to exercise the option?

If both answers are positive, the contract contains a written option.

Quantitative test

The quantitative test can take the form of comparing the price charged in the contract with the flexibility to the price charged in otherwise similar contracts with no flexibility. The entity might need a sophisticated valuation system and a relatively large number of data inputs (which might require access to historical data) that can value options over commodities to carry out the test if there are no similar contracts without volume flexibility.

The existence of a premium, paid at inception or over the life of the contract, is a good quantitative indicator for the existence of a written option. [IAS 39 IG para F.1.3]. Conversely, if the writer of the option can demonstrate that it received no premium, this would indicate that the contract does not contain a written option.

Two approaches are available if management determines that a commodity supply/sale contract contains a written option component:

- 1) The contract is deemed to consist of a fixed price/ fixed volume part and a fixed price/written option volume part. The fixed price contract is outside the scope of IAS 39 if it fulfils the own use requirements in paragraph 5 of IAS 39. However, the written option volume part would be treated as a derivative and would be fair valued through profit or loss in accordance with paragraph 7 of IAS 39.
- 2) The contract is evaluated as a single contract. The contract is considered as a whole to be a written option. Accordingly, paragraph 7 of IAS 39 would be applicable to the contract in its entirety, because the entity cannot consider the contract as held for own use by the counterparty. Hence, the entire contract is treated as a derivative and fair valued through profit or loss.

Both approaches are seen in practice. It is an accounting policy choice which should be applied consistently to similar transactions, as per paragraph 13 of IAS 8.

2.6 Embedded derivatives

Long-term commodity purchase and sale contracts frequently contain a pricing clause (that is, indexation) based on a commodity or index other than the commodity deliverable under the contract. Such contracts contain embedded derivatives that might have to be separated and accounted for under IAS 39 as a derivative. Examples are fuel prices that are linked to the electricity price, or pricing formulas that include 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 can change some or all of the cash flows of the host contract. 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 (that is, a derivative 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. In rare cases, it might not be possible to measure the embedded derivative. In those cases, the entire combined contract must be measured at fair value, with changes in fair value recognised in the income statement. An embedded derivative that is required to be separated could be designated as a hedging instrument, in which case the hedge accounting rules are applied. A contract that contains one or more embedded derivatives can be designated as a contract at fair value through profit or loss at inception, unless:

- a) the embedded derivative(s) does not significantly modify the cash flows of the contract; and
- b) it is clear, with little or no analysis, that separation of the embedded derivative(s) is prohibited.

Assessing whether embedded derivatives are closely related

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 as follows: indexation of a published market price; and denomination in a foreign currency that is not the functional currency of either party and is not a currency in which such contracts are routinely denominated in transactions around the world.

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

In the absence of an active market price for a particular commodity, management should consider how other contracts for that particular commodity are normally priced. It is common for a pricing formula to be developed as a proxy for market prices. Where it can be demonstrated that a commodity contract is priced by reference to an identifiable industry norm, and that 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.

Example – 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?

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.

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.

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 potential embedded derivatives is prohibited, unless there is a significant change in the terms of the contract, in which case reassessment is required. A significant change in the terms of the contract occurs where the expected future cash flows associated with the embedded derivative, host contract or hybrid contract significantly change from the previously expected cash flows under the contract.

A first-time adopter of IFRS 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 when it first became a party to the contract and the date when a reassessment is required.

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

Example – Embedded derivatives

Utility A acquires entity B in a business combination under IFRS. In 2000, entity B entered into a long-term gas purchase contract, with prices indexed to gas and fuel oil that it determined met the own use exemption. In 2000 the gas market was not active. At the date of acquisition, this gas market is active and therefore gas meets the net settlement criteria under paragraph 6(d) of IAS 39. The utility must assess the contract as if it entered into it at the date of the business combination. Therefore, embedded derivatives need to be evaluated.

Under the assumption that the contract still meets the own use exemption, the gas and fuel oil price indices need to be bifurcated and accounted for as derivatives separately, because they are not closely related to the gas price (that is, the quantitative analysis failed). The contract is recorded at its fair value at acquisition date, but it is not accounted for as a derivative in the post-acquisition period. Both price indices have to be recorded with a fair value of nil at acquisition date and accounted for as derivatives in the post-acquisition period.

LNG contracts

The liquefied natural gas (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:

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

The application of the own use exemption could become quite complex, particularly for the definition of 'net settlement'. The principles of paragraphs 5–7 of IAS 39 should still be applied; however, there might be some practical challenges to this. The explanation of how energy trading units operate (in section 2.8) 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 (such as the Henry Hub Natural gas index or Brent Oil index). 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.

2.7 Hedge accounting

Principles and types of hedging

Hedge accounting can mitigate the volatility of trading transactions. From a practical perspective, complying with the requirements of hedge accounting can be onerous. Entities that qualify for the own use exemption might find it operationally easier to use than hedge accounting. An entity that chooses to apply hedge accounting must comply with the detailed requirements. All derivatives are accounted for at fair value, but changes in fair value are either deferred through reserves in other comprehensive income (cash flow hedge) or matched, to a significant extent, in the income statement by an adjustment to the value of the hedged item (fair value hedge).

There are two hurdles to implementing hedge accounting: the need for documentation; and the testing of effectiveness. IAS 39 requires individual hedging relationships to be formally documented, at inception of the hedge, including linkage of the hedge to the entity's risk-management strategy, explicit identification of the hedged items and the specific risks being hedged. Failure to establish this documentation at inception precludes hedge accounting, regardless of how effective the hedge actually is in offsetting risk.

Hedges must be expected to be highly effective and must prove to be highly effective in mitigating the hedged risk or variability in cash flows in the underlying instrument.

There is no prescribed single method for assessing hedge effectiveness. Instead, an entity must identify a method that is appropriate to the nature of the risk being hedged and the type of hedging instrument used. The method that an entity adopts for assessing hedge effectiveness depends on its risk management strategy. An entity must document, at the inception of the hedge, how effectiveness will be assessed; and it must then apply that effectiveness test on a consistent basis for the duration of the hedge.

The hedge must be expected to be highly effective at the inception of the hedge and in subsequent periods; the actual results of the hedge should be within a range of 80%–125% effective (that is, 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).

Testing for hedge effectiveness can be quite onerous. Effectiveness tests need to be performed for each hedging relationship at least as frequently as financial information is prepared; for listed companies, this could be up to four times a year. An entity interested in applying hedge accounting to its commodity hedges needs to invest time in ensuring that appropriate effectiveness tests are developed.

The IASB has an ongoing project on hedge accounting. Two significant expected developments for energy companies are a proposed relaxation in the requirements for hedge effectiveness, and the ability to hedge non-financial portions in some circumstances. These might make hedge accounting much more attractive. Entities should monitor the progress on this and assess what the impact on their current accounting will be.

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 is therefore a cash flow hedge. 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 unable to forecast the hedged transactions reliably.

Entities (such as utilities) that buy or sell commodities can 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.

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 can be designated as a hedged item only for:

- a) foreign currency risks;
- b) in its entirety, 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.

Weather derivatives

Gas and electricity consumption is heavily influenced by the weather. More energy is consumed in cold winters and hot summers than in mild winters and cool summers. Weather derivatives make it possible to manage the concerns related to extreme climate conditions by paying the generator when the weather adversely affects revenue.

Weather derivatives are contracts that require a payment based on climatic, geological or other physical variables. For such contracts, payments might or might not be based on the amount of loss suffered by the entity. Weather derivatives are either insurance contracts (and so fall into IFRS 4) or financial instruments (and fall within the scope of IAS 39). Contracts that require a payment only if a particular level of the underlying climatic, geological or other physical variables adversely affects the contract holder are insurance contracts. Payment is contingent on changes in a physical variable that is specific to a party to the contract.

Contracts that require a payment based on a specified level of the underlying variable, regardless of whether there is an adverse effect on the contract holder, are derivatives and are within IAS 39's scope.

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 (that is, as if the hedge relationship started at the acquisition date). Since derivatives previously designated as hedging derivatives were entered into by the acquired entity before the acquisition, these contracts are unlikely to have a fair value of nil 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 might meet the definition of a written option when the acquiring entity reassesses them at the acquisition date. Consequently, the acquiring entity will not be able to designate such derivatives as hedging instruments.

2.8 Trading and risk management

Energy trading is the buying and selling of energy-related products, both fuel and power. This practice has many similarities to the trading activities of other commodities, such as gold, sugar or wheat. The introduction of competition in the utilities area was the catalyst for energy trading to start in earnest. Energy trading is an important but potentially risky part of a utility's business. However, effective trading can also limit volatility and protect profit margins.

Centralised trading unit

Many integrated utility companies have established a centralised trading or risk management unit over the last decade, in response to the restructuring of the industry. The operation of the central trading unit is similar to the operation of the bank's trading unit.

The scale and scope of the unit's activities vary, from market risk management through to dynamic profit optimisation. An integrated utility entity is particularly exposed to the movements in the price of fuel and to movements in the price of the power generated. The trading unit's objectives and activities are indicative of how management of the utility operates the business.

A unit focused on managing fuel-price risk and sales-price exposure to protect margins is more likely to enter into many contracts that qualify for the own use exemption. A pattern of speculative activity or trading directed to profit maximisation is unlikely to result in many contracts qualifying for the own use exemption. The central trading unit often operates as an internal marketplace in larger integrated utilities. The generating stations 'sell' their output to – and 'purchase' fuel from – the trading unit. The retail unit would 'purchase' power to meet its customer demands. The centralised trading function thus 'acquires' all of the entity's exposure to the various commodity risks. The trading unit is then responsible for hedging those risks in the external markets.

Some centralised trading departments are also given authority to enhance the returns obtained from the integrated business by undertaking optimisation activities, which include asset-based trading and speculative trading. A centralised trading unit therefore undertakes transactions for two purposes:

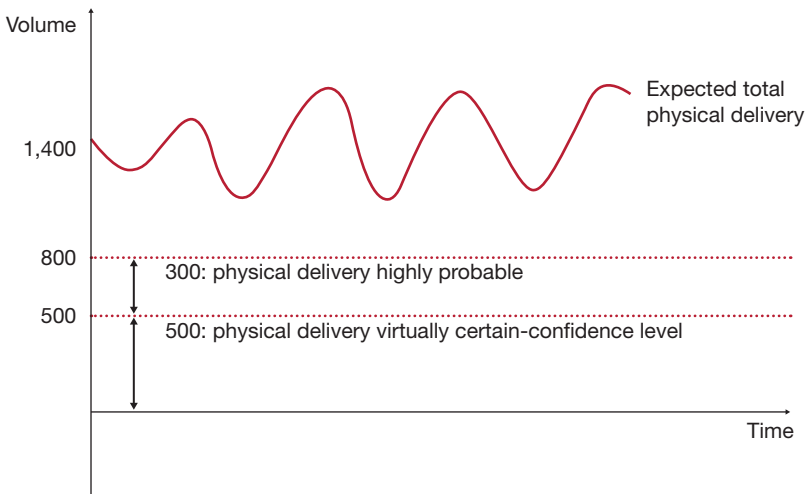
- a) Transactions that are non-speculative in nature – the purchase of fuel to meet the physical requirements of the generating stations and the sale of any excess power generated compared to retail demand, or the purchase of power to meet a shortfall between that generated and that required by retail. This is often characterised by management as price-risk management, with volume risks relating to operational assets and customer demand remaining within the operational divisions (that is, no re-optimisation to take advantage of market price movements). Such activity is sometimes held in a 'physical book'.
- b) Transactions that are speculative in nature – to achieve risk management returns from wholesale trading activities. Such activity is sometimes held in a 'trading book'. The result of carrying out the transactions in (a) in an optimal manner (without re-optimisation) would be the elimination of price risk and the management of revenues and costs in future periods. If an entity maintains separate physical and trading books, the contracts in the physical book might qualify for the own use exemption.

An entity 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 might 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.

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 ceases to be accounted for as a contract for own use purposes.
- 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 entity's management (such as a power plant 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 as a separate line (for example, 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.

3 Future developments – standards issued and not yet effective

3 Future developments – standards issued and not yet effective

3.1 Rate-regulated activities

The IASB has an existing research project on rate-regulated activities. The plan is to develop a discussion paper (DP) using the work performed to date on the existing rate-regulated activities project and research from the Conceptual Framework project.

The DP will explore how the rights and obligations of rate-regulated entities differ across regulatory jurisdictions, whether those rights and obligations support recognition of assets and liabilities, and an analysis of current practice under IFRS by jurisdiction. As of the date of this publication, the IASB plans to publish the DP in Q2 of 2014.

3.2 Financial instruments

IFRS 9

The IASB has issued IFRS 9, *Financial Instruments*, which addresses the classification and measurement of financial assets and liabilities. It replaces the existing guidance under IAS 39. IFRS 9 is applicable from 1 January 2015, and early adoption is permitted. IFRS 9 should be applied retrospectively.

The main feature of IFRS 9 is that it emphasises the entity's business model when classifying financial assets. Accordingly, the business model and the characteristics of the contractual cash flows of the financial asset determine whether the financial asset is subsequently measured at amortised cost or fair value. This is a key difference from current practice.

How does it impact the power and utilities sector?

The effect of IFRS 9 on the financial reporting of utility entities is expected to vary significantly, depending on entities' investment objectives. Utility entities will be impacted by the new standard if they hold many or complex financial assets. The degree of the impact will depend on the type and significance of financial assets held by the entity and the entity's business model for managing financial assets.

For example, entities that hold bond instruments with complex features (such as interest payments linked to entity performance or foreign exchange rates) will be significantly impacted. In contrast, utility entities that hold only shares in publicly listed companies that are not held for trading will not be impacted, because these continue to be measured at fair value, with changes taken to the income statement.

What are the key changes for financial assets?

IFRS 9 replaces the multiple classification and measurement models in IAS 39, *Financial Instruments: Recognition and Measurement*, with a single model that has only two classification categories: amortised cost; and fair value. A financial instrument is measured at amortised cost if two criteria are met:

- a) the objective of the business model is to hold the financial instrument for the collection of the contractual cash flows; and
- b) the contractual cash flows under the instrument solely represent payments of principal and interest.

If these criteria are not met, the asset is classified at fair value. This will be welcome news for most utility entities that hold debt instruments with simple loan features (such as bonds that pay only fixed interest payments and the principal amount outstanding) which are not held for trading.

The new standard removes the requirement to separate embedded derivatives from the rest of a financial asset. It requires a hybrid contract to be classified in its entirety at either amortised cost or fair value. In practice, we expect many of these hybrid contracts to be measured at fair value. The convertible bonds held by utility entities are often considered to be hybrid contracts and might need to be measured at fair value.

IFRS 9 prohibits reclassifications from amortised cost to fair value (or vice versa), except in rare circumstances where the entity's business model changes. In cases where it does, entities will need to reclassify affected financial assets prospectively.

There is specific guidance for contractually linked instruments that create concentrations of credit risk, which is often the case with investment tranches in a securitisation. In addition to assessing the instrument itself against the IFRS 9 classification criteria, management should also 'look through' to the underlying pool of instruments that generate cash flows, to assess their characteristics. To qualify for amortised cost, the investment must have equal or lower credit risk than the weighted-average credit risk in the underlying pool of other instruments, and those instruments must meet certain criteria. If a look through is impractical, the tranche must be classified at fair value through profit or loss.

Under IFRS 9, all equity investments should be measured at fair value. However, management has an option to present, in other comprehensive income, unrealised and realised fair value gains and losses on equity investments that are not held for trading. Such designation is available on initial recognition, on an instrument-by-instrument basis, and it is irrevocable. There is no subsequent recycling of fair value gains and losses on disposal to the income statement; however, dividends from such

investments will continue to be recognised in the income statement. This is good news for many, because utility entities might own ordinary shares in public entities. As long as these investments are not held for trading, fluctuations in the share price will be recorded in other comprehensive income. Under the new standard, recent events such as the global financial crisis will not yield volatile results in the income statement from changes in the share prices.

How could current practice change for power and utility entities?

Type of instrument/ Categorisation of instrument	Accounting under IAS 39	Accounting under IFRS 9	Insight
<p>Investments in equity instruments that are not held for trading purposes (e.g., equity securities of a listed entity).</p> <p><i>Note. This does not include associates or subsidiaries unless entities specifically make that election.</i></p>	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 applicable.	Equity securities that are not held for trading can be classified and measured at fair value with gains/losses recognised in other comprehensive income. 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.	Measured at amortised cost where certain criteria are met. Where criteria are not met, measured at fair value through profit and loss.	Determining whether the debt instrument meets the criteria for amortised cost can be challenging in practice. It involves determining what the bond payments represent. If they represent more than principal and interest on principal outstanding (e.g., 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.

Type of instrument/ Categorisation of instrument	Accounting under IAS 39	Accounting under IFRS 9	Insight
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.	<p>Many entities found the separation of conversion options and the requirement to separately fair value the instrument challenging.</p> <p>However, management should be aware that the entire instrument will now be measured at fair value. This may result in a more volatile income statement because it will need to have fair value gains/losses recognised not only on the conversion option, but also on the entire instrument.</p>
Held-to-maturity investments (e.g., government bonds)	Measured at amortised cost.	Measured at amortised cost where certain criteria are met. Where criteria are not met, measured at fair value through profit and loss.	<p>Determining whether the government bond payments meet the criteria for amortised cost remains a challenge. For example, if the government bond includes a component for inflation, as long as the payment represents only compensation for time value of money, it may still meet the criteria for amortised cost. In contrast, a government bond that is linked to foreign currency exchange rates would not meet the criteria for amortised cost; instead this would need to be measured at fair value through profit and loss.</p>

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 where there is no expectation that the change in the liability's credit risk will be realised. In view of this concern, the IASB has retained the existing guidance in IAS 39 regarding classifying and measuring financial liabilities, except for those liabilities where the fair value option has been elected.

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).

In practice, 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. In addition, entities might 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 where the liability is derecognised and the amounts are realised. However, the standard does allow transfers within equity.

What else should entities in the power and utilities sector know about the new standard?

Entities that currently classify their investments as loans and receivables need to carefully assess whether their business model is based on managing the investment portfolio to collect the contractual cash flows from the financial assets. To meet that objective, the entity does not need to hold all of its investments until maturity, but the business must be holding the investments to collect their contractual cash flows.

We expect most utility entities to be managing their loans and receivables (normally trade receivables) to collect their contractual cash flows. As a result, for many entities these new rules will not have a significant impact on their financial assets.

Entities in the utility sector that manage their investments and monitor performance on a fair value basis will need to fair value their financial assets with gains and losses recognised in the income statement. Primarily, that is because their business model is not considered to be based on managing the investment portfolio to collect the contractual cash flows, and so a different accounting treatment is required. We expect only a minority of entities in the sector to be managing their investments on this basis.

Some entities made use of the cost exception in the existing IAS 39 for their unquoted equity investments. Under the new standard, these entities can continue to use cost only where it is an appropriate estimate of fair value. Utility entities should be aware that the scenarios in which cost would be an appropriate estimate of fair value are limited to cases where insufficient recent information is available to determine the fair value. Therefore, entities will need to implement mechanisms to determine fair value periodically. There will be a substantial impact on entities that hold investments in unlisted entities where the investing entity does not have significant influence. This could significantly affect businesses, because IFRS 9 requires a process or system in place to determine the fair value or range of possible fair value measurements.

Entities that currently classify their financial assets as available-for-sale and plan to make use of the 'other comprehensive income option' to defer fair value gains should be aware that it is only available for equity investments on an instrument-by-instrument basis. These entities will not be able to use other comprehensive income for debt instruments. Once this election is made, it will irrevocably prevent the entity

from recycling gains and losses through the income statement on disposal. For some entities in the sector, this will remove some of the freedoms they currently enjoy with the accounting for debt instruments.

Entities in the utility sector might wish to consider early adopting the standard, particularly where they have previously recorded impairment losses on equity investments that are not held for trading or where they would like to reclassify their financial assets. On adoption of this standard, entities need to apply the new rules retrospectively. This will allow some entities to reverse some impairment charges recognised on listed equity securities as a result of the global financial crisis, as long as they are still holding the investment. We expect that some utility entities will consider early adopting the standard to take advantage of this.

Management should bear in mind that the financial instruments project is evolving: IFRS 9 is only the first part of the project to replace IAS 39. Other exposure drafts have been issued in respect of asset-liability offsetting and hedge accounting with the intention of improving and simplifying hedge accounting.

Appendices

Appendix A – Financial statement disclosure examples

The following financial statement disclosure examples represent extracts from the annual reports and accounts of the relevant companies. These should be read in conjunction with the relevant full annual report and accounts for a full understanding.

Decommissioning

E.ON SE (31 December 2013)

Provisions for Asset Retirement Obligations and Other Miscellaneous

Provisions In accordance with IAS 37, “Provisions, Contingent Liabilities and Contingent Assets,” (“IAS 37”) provisions are recognized when E.ON has a legal or constructive present obligation towards third parties as a result of a past event, it is probable that E.ON will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. The provision is recognized at the expected settlement amount. Long-term obligations are reported as liabilities at the present value of their expected settlement amounts if the interest rate effect (the difference between present value and repayment amount) resulting from discounting is material; future cost increases that are foreseeable and likely to occur on the balance sheet date must also be included in the measurement. Long-term obligations are discounted at the market interest rate applicable as of the respective balance sheet date. The accretion amounts and the effects of changes in interest rates are generally presented as part of financial results. A reimbursement related to the provision that is virtually certain to be collected is capitalized as a separate asset. No offsetting within provisions is permitted. Advance payments remitted are deducted from the provisions.

Obligations arising from the decommissioning or dismantling of property, plant and equipment are recognized during the period of their occurrence at their discounted settlement amounts, provided that the obligation can be reliably estimated.

The carrying amounts of the respective property, plant and equipment are increased by the same amounts. In subsequent periods, capitalized asset retirement costs are amortized over the expected remaining useful lives of the assets, and the provision is accreted to its present value on an annual basis.

Changes in estimates arise in particular from deviations from original cost estimates, from changes to the maturity or the scope of the relevant obligation, and also as a result of the regular adjustment of the discount rate to current market interest rates.

The adjustment of provisions for the decommissioning and restoration of property, plant and equipment for changes to estimates is generally recognized by way of a corresponding adjustment to these assets, with no effect on income. If the property, plant and equipment to be decommissioned have already been fully depreciated, changes to estimates are recognized within the income statement.

The estimates for non-contractual nuclear decommissioning provisions are based on external studies and are continuously updated.

Under Swedish law, E.ON Sverige AB (“E.ON Sverige”) is required to pay fees to the Swedish Nuclear Waste Fund. The Swedish Radiation Safety Authority proposes the fees for the disposal of high-level radioactive waste and nuclear power plant decommissioning based on the amount of electricity produced at that particular nuclear power plant. The proposed fees are then submitted to government offices for approval. Upon approval, E.ON Sverige makes the corresponding payments. In accordance with IFRIC 5, “Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds,” (“IFRIC 5”) payments into the Swedish national fund for nuclear waste management are offset by a right of reimbursement of asset retirement obligations, which is recognized as an asset under “Other assets.” In accordance with customary procedure in Sweden, the provisions are discounted at the real interest rate.

No provisions are established for contingent asset retirement obligations where the type, scope, timing and associated probabilities can not be determined reliably.

If onerous contracts exist in which the unavoidable costs of meeting a contractual obligation exceed the economic benefits expected to be received under the contract, provisions are established for losses from open transactions. Such provisions are recognized at the lower of the excess obligation upon performance under the contract and any potential penalties or compensation arising in the event of non-performance. Obligations under an open contractual relationship are determined from a customer perspective.

Contingent liabilities are possible obligations toward third parties arising from past events that are not wholly within the control of the entity, or else present obligations toward third parties arising from past events in which an outflow of resources embodying economic benefits is not probable or where the amount of the obligation cannot be measured with sufficient reliability. Contingent liabilities are generally not recognized on the balance sheet.

Where necessary, provisions for restructuring costs are recognized at the present value of the future outflows of resources. Provisions are recognized once a detailed restructuring plan has been decided on by management and publicly announced or communicated to the employees or their representatives. Only those expenses that are directly attributable to the restructuring measures are used in measuring the amount of the provision. Expenses associated with the future operation are not taken into consideration.

GDF Suez SA (31 December 2013)

18.2.3 Provisions for dismantling nuclear facilities

Nuclear power stations have to be dismantled at the end of their operating life. Provisions are set aside in the Group's accounts to cover all costs relating to (i) the shutdown phase, which involves removing radioactive fuel from the site and (ii) the dismantling phase, which consists of decommissioning and cleaning up the site.

Provisions for dismantling nuclear facilities are calculated based on the following principles and parameters:

- costs payable over the long term are calculated by reference to the estimated costs for each nuclear facility, based on a study conducted by independent experts under the assumption that the facilities will be dismantled progressively;
- an inflation rate of 2.0% is applied until the dismantling obligations expire in order to determine the value of the future obligation;
- a discount rate of 4.8% (including 2.0% inflation) is applied to determine the present value (NPV) of the obligation. This rate is the same as the one used to calculate the provision for processing nuclear spent fuel;
- the operating life is 50 years for Tihange 1 and 40 years for the other facilities;

- it generally takes three to four years to shut down a reactor. The start of the technical shut-down procedures depends on the facility concerned and on the timing of operations for the nuclear reactor as a whole. The shutdown procedures are immediately followed by dismantling operations, which last from 9 to 13 years;
- the present value of the obligation when the facilities are commissioned represents the initial amount of the provision. The matching entry is an asset recognized for the same amount within the corresponding property, plant and equipment category. This asset is depreciated over the remaining operating life as from the commissioning date;
- the annual allocation to the provision, reflecting the interest cost on the provision carried in the books at the end of the previous year, is calculated at the discount rate used to estimate the present value of future cash flows.

The costs effectively incurred in the future may differ from the estimates in terms of their nature and timing of payment. The provisions may be adjusted in line with future changes in the above-mentioned parameters. However, these parameters are based on information and estimates which the Group deems reasonable to date and which have been approved by the Commission for Nuclear Provisions.

The scenario adopted is based on a dismantling program and on timetables that have to be approved by nuclear safety authorities.

Provisions are also recognized at the Group's share of the expected dismantling costs for the nuclear facilities in which it has drawing rights.

Impairment

Centrica plc (31 December 2013)

Impairment of property, plant and equipment, intangible assets, investments in joint ventures and associates and goodwill

The Group reviews the carrying amounts of PP&E, intangible assets, interests in joint ventures and associates and goodwill annually, or more frequently if events or changes in circumstances indicate that the recoverable amounts may be lower than their carrying amounts. Where an asset does not generate cash flows that are independent from other assets, the Group estimates the recoverable amount of the CGU to which the asset belongs. The recoverable amount is the higher of value in use (VIU) and fair value less costs to sell (FVLCS).

At inception, goodwill is allocated to each of the Group's CGUs or groups of CGUs that expect to benefit from the business combination in which the goodwill arose. If the recoverable amount of an asset (or CGU) is estimated to be less than its carrying amount, the carrying amount of the asset (or CGU) is reduced to its recoverable amount. Any impairment is expensed immediately in the Group Income Statement. Any CGU impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to the other assets of the unit pro rata on the basis of the carrying amount of each asset in the unit.

An impairment loss is reversed only if there has been a change in the estimate used to determine the asset's recoverable amount since the last impairment loss was recognised, with the exception of goodwill impairment which is never reversed. Where an impairment loss subsequently reverses, the carrying amount of the asset (or CGU) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset (or CGU) in prior years. A reversal of an impairment loss is recognised in the Group Income Statement immediately. After such a reversal the depreciation or amortisation charge, where relevant, is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Value in use calculations have been used to determine recoverable amounts for all of the goodwill and indefinite-lived intangible asset balances with the exception of the impairment tests for the Centrica Energy – Upstream gas and oil CGUs, where fair value less costs to sell has been used as the basis for determining recoverable amount. This methodology is deemed to be more appropriate as it is based on the post-tax cash flows arising from the underlying assets and is consistent with the approach taken by management to evaluate the economic value of the underlying assets. Further details of the VIU and FVLCS calculation assumptions are provided below. The FVLCS section is also relevant to how the Upstream gas and oil property, plant and equipment impairments, as detailed in note 7, were calculated.

Fortum Corporation (31 December 2013)

Impairment of non-financial assets

The individual assets' carrying values are reviewed at each closing date to determine whether there is any indication of impairment. An asset's carrying amount is written down immediately to its recoverable amount if it is greater than the estimated recoverable amount.

When considering the need for impairment the Group assesses if events or changes in circumstances indicate that the carrying amount may not be recoverable. This assessment is documented once a year in connection with the Business Plan process. Indications for impairment are analysed separately by each division as they are different for each business and include risks such as changes in electricity and fuel prices, regulatory/political changes relating to energy taxes and price regulations etc. Impairment testing needs to be performed if any of the impairment indications exists. Assets that have an indefinite useful life, such as goodwill, are not subject to amortisation and are tested annually for impairment.

An impairment loss is recognised in the income statement for the amount by which the assets' carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purpose of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units). Goodwill is allocated to cash-generating units for the purpose of impairment testing. The allocation is made to those cash-generating units or groups of cash-generating units that are expected to benefit from the business combination in which the goodwill arose.

Value in use is determined by discounting the future cash flows expected to be derived from an asset or cash-generating unit. Cash flow projections are based on the most recent Business Plan that has been approved by management. Cash flows arising from future investments such as new plants are excluded unless projects have been started. The cash outflow needed to complete the assets is included.

The period covered by cash flows is related to the useful lives of the assets reviewed for impairment. Normally projections should cover a maximum period of five years but as the useful lives of power plants and other major assets are over 20 years, the projection period is longer. Cash flow projections beyond the period covered by the most recent business plan are estimated by extrapolating the projections using a steady or declining growth rate for subsequent years.

Non-financial assets other than goodwill that suffered an impairment charge are reviewed for possible reversal of the impairment at each reporting date.

Iberdrola, S.A. (31 December 2013)

Non-Financial assets impairment

Each closing date at every accounting year, the IBERDROLA Group reviews the carrying amounts of its non-current assets to determine whether there is any indication that those assets have suffered an impairment loss. If such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss, if it is necessary. For this purpose, in the case of assets that do not generate cash flows independent from other assets, IBERDROLA Group estimates the recoverable amount of the cash-generating unit to which belongs.

In the case of goodwill and other intangible assets which have not come into use or which have an indefinite useful life, the IBERDROLA Group performs the recoverability analysis systematically every year, except when there are signs of impairment in another moment, in which case recoverability analysis is performed at the same time.

For purposes of this recoverability analysis, goodwill is allocated to the cash generating units in which it is controlled for internal management purposes (Note 8).

Recoverable amount is the higher of fair value less selling cost and value in use, which is taken to be the present value of the estimated future cash flows. The assumptions used in assessing value in use, in making the estimates include discount rates, growth rates and expected changes in selling prices and direct costs. The discount rates reflect the time value of money and the risks specific to each cash-generating unit. The growth rates and the changes in prices and direct costs are based on contractual commitments that have already been signed, information in the public domain, sector forecasts and the experience of the IBERDROLA Group (Note 11).

If the recoverable amount of an asset is less than its carrying amount, an impairment loss is recognised for the difference with a charge to “Amortisation and provisions” in the Consolidated income statement. Impairment losses recognised for an asset are reversed with a credit to the aforementioned heading when there is a change in the estimates concerning the recoverable amount of the asset, increasing the carrying amount of the asset, but so the increased carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognised, except in the case of the goodwill, which impairment is not reversible.

Arrangements that might contain a lease

CEZ, a.s. (31 December 2013)

2.27. Leases

The determination of whether an arrangement is, or contains a lease is based on the substance of the arrangement at inception date or whether the fulfillment of the arrangement is dependent on the use of a specific asset or assets or the arrangement conveys the right to use the asset. A reassessment is made after inception of the lease only if one of the following conditions applies:

- There is a change in contractual terms, other than a renewal or extension of the arrangement;
- A renewal option is exercised or extension granted, unless the term of the renewal or extension was initially included in the lease term;
- There is a change in determination of whether fulfillment is dependent on a specified asset; or
- There is a substantial change to the asset.

Where reassessment is made, lease accounting shall commence or cease from the date when the change in circumstances gave rise to the reassessment.

Finance leases, which transfer to the Group substantially all the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Lease payments are apportioned between the finance charges and reduction of the lease liability so as to achieve a constant rate of interest on the remaining balance of the liability. Finance charges are charged directly against income.

Capitalized leased assets are depreciated over the estimated useful life of the asset. If there is no reasonable certainty that the lessee will obtain ownership by the end of the lease term, the asset is fully depreciated over the shorter of the lease term or its useful life.

Leases where the lessor retains substantially all the risks and benefits of ownership of the asset are classified as operating leases. Operating lease payments are recognized as an expense in the income statement on a straight-line basis over the lease term.

Emissions Trading Scheme and Certified Emission Reduction

Vattenfall AB (31 December 2013)

Emission allowances held for own use

Since 2005, a trading system applies in the EU (the Emission Trading Scheme – ETS) with the purpose of reducing emissions of the greenhouse gas carbon dioxide. Within the framework of this system, some concerned plants have received, without payment or for prices below fair value, so-called emission allowances (European Union Allowances – EUAs) from the authorities in each country. Sales and purchases of emission allowances are conducted on designated exchanges, where plants that have a greater need for emission allowances than their free-of-charge or subsidised allocation are required to purchase allowances to cover their remaining need and thereby settle their obligations.

During the first trading period, 2005–2007, trading was conducted only in EUAs. During the second trading period, 2008–2012, trading was conducted in parallel with the first commitment period in the Kyoto Protocol, and the EU's Emission Trading Scheme was opened up to international trading in Certified Emission Reductions (CERs) and Emission Reduction Units (ERUs).

Starting with the third trading period (2013–2020) there is no free-of-charge or subsidised allocation of emission allowances for the power generation sector, meaning that all power generators must purchase all of their emission allowances. In sectors other than power generation, e.g., heat generation, free-of-charge allocations will be available during a transition period, however with decreasing levels in the coming years during the transition period.

Purchased emission allowances held for own use are reported as intangible assets under current assets at cost less accumulated impairment losses, while emission allowances that have been received free of charge from the respective countries' authorities are stated at a value of SEK nil. As carbon dioxide is emitted, an obligation arises to deliver emission allowances (EUAs, CERs, ERUs) to the authorities in the respective countries. An expense and a liability are recognised in cases where the emission allowances that were received free of charge do not cover this obligation. This liability is valued in the amount at which it is expected to be settled.

Certificates held for own use

With the aim to increase renewable energy sources for electricity generation, Sweden and UK, among other countries, have so-called electricity certificate systems. Plants included in these systems receive, free of charge from the authorities in the respective countries, certificates in pace with their generation of electricity qualifying for certificates.

Accumulated certificates, which are received free of charge, are reported as an intangible asset under current assets at fair value when obtained. The corresponding amount is recognised as revenue under Net sales. Purchased certificates held for own use are reported at cost less accumulated impairment losses.

When electricity is sold, an obligation arises to deliver certificates to the authorities in the respective countries. This obligation is reported as an expense and as a liability. The liability is valued at the amount at which it is expected to be settled.

Clean Development Mechanism

Clean Development Mechanism (CDM) is a flexible mechanism under the Kyoto Protocol and overseen by the UNFCCC under which projects set up in developing countries to reduce CO₂ emissions can generate tradable carbon credits called CERs (Certified Emission Reductions). Once CERs are issued by the UNFCCC they can be used by companies and governments in industrialised nations as carbon offsets at home to meet their reduction targets, either under the EU ETS in the case of a company or under the Kyoto Protocol in case of countries. In terms of valuation of the CDM projects in Vattenfall's CDM portfolio, the non-observable input factor is an estimation of the volume of CERs that is expected to be delivered from each project annually. This estimation is derived from six defined Risk Adjustment Factors (RAFs) that have the same weighting. These project specific factors are calculated using the Carbon Valuation Tool developed by Point Carbon to quantify the risk by adjusting the volume based on these six risks and calculating the fair value based on these six risk adjusted volumes against the CER forward curve on the exchange (Inter Continental Exchange – ICE). The tool is based on Point Carbon's valuation methodology, which was developed in cooperation with several experienced market players. The valuation methodology is strictly empirical, and all risk parameters are extracted from Point Carbon's proprietary databases of CDM project data, which entails a correct valuation of the contracts. The results are validated based on monitoring reports for the respective CDM projects, which are publicly available on the website of the UNFCCC.

The net value as per 31 December 2013 has been calculated at SEK -1 million (-414). The fair value is mainly determined and correlated with the observable price of CER, meaning a higher price of CER leads to a higher value of the CDM contract and vice versa. A change in the modelled price of CERs of +/-5% would affect the total value by approximately SEK +/-3 million (+/-5).

Centrica plc (31 December 2013)

EU Emissions Trading Scheme and renewable obligations certificates

Granted carbon dioxide emissions allowances received in a period are recognised initially at nominal value (nil value). Purchased carbon dioxide emissions allowances are recognised initially at cost (purchase price) within intangible assets. A liability is recognised when the level of emissions exceeds the level of allowances granted. The liability is measured at the cost of purchased allowances up to the level of purchased allowances held, and then at the market price of allowances ruling at the Balance Sheet date, with movements in the liability recognised in operating profit.

Forward contracts for the purchase or sale of carbon dioxide emissions allowances are measured at fair value with gains and losses arising from changes in fair value recognised in the Group Income Statement. The intangible asset is surrendered and the liability is utilised at the end of the compliance period to reflect the consumption of economic benefits.

Purchased renewable obligation certificates are recognised initially at cost within intangible assets. A liability for the renewables obligation is recognised based on the level of electricity supplied to customers, and is calculated in accordance with percentages set by the UK Government and the renewable obligation certificate buyout price for that period.

The intangible asset is surrendered and the liability is utilised at the end of the compliance period to reflect the consumption of economic benefits. Any recycling benefit related to the submission of renewable obligation certificates is recognised in the Group Income Statement when received.

Customer Contributions

E.ON SE (31 December 2013)

Capital expenditure grants of €465 million (2012: €502 million) were paid primarily by customers for capital expenditures made on their behalf, while the E.ON Group retains ownership of the assets.

The grants are non-refundable and are recognized in other operating income over the period of the depreciable lives of the related assets.

Construction grants of €2,335 million (2012: €2,629 million) were paid by customers for the cost of new gas and electricity connections in accordance with the generally binding terms governing such new connections. These grants are customary in the industry, generally non-refundable and recognized as revenue according to the useful lives of the related assets.

Regulatory Assets & Liabilities

National Grid plc (31 March 2013)

Revenue primarily represents the sales value derived from the generation, transmission and distribution of energy, together with the sales value derived from the provision of other services to customers and, previously, recovery of US stranded costs during the year. It excludes value added (sales) tax and intra-group sales.

Revenue includes an assessment of unbilled energy and transportation services supplied to customers between the date of the last meter reading and the year end. This is estimated based on historical consumption and weather patterns.

Where revenue exceeds the maximum amount permitted by regulatory agreement and adjustments will be made to future prices to reflect this over-recovery, no liability is recognised, as such an adjustment relates to the provision of future services. Similarly no asset is recognised where a regulatory agreement permits adjustments to be made to future prices in respect of an under-recovery.

Business Combinations

RWE AG (31 December 2013)

Business combinations are reported according to the acquisition method. This means that capital consolidation takes place by offsetting the purchase price, including the amount of the minority interest, against the acquired subsidiary's revalued net assets at the time of acquisition. In doing so, the minority interest can either be measured at the prorated value of the subsidiary's identifiable net assets or at fair value. The subsidiary's identifiable assets, liabilities and contingent liabilities are measured at full fair value, regardless of the amount of the minority interest. Intangible assets are reported separately from goodwill if they are separable from the company or if they stem from a contractual or other right. In accordance with IFRS 3, no new restructuring provisions are recognised within the scope of the purchase price allocation. If the purchase price exceeds the revalued prorated net assets of the acquired subsidiary, the difference is capitalised as goodwill. If the purchase price is lower, the difference is included in income.

Joint arrangements

OAO Gazprom (31 December 2013)

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

5.1 Group accounting

Joint arrangements

The group has applied IFRS 11 "Joint Arrangements" ("IFRS 11") to all joint arrangements as of 1 January 2012. Under IFRS 11 investments in joint arrangements are classified as either joint operations or joint ventures depending on the contractual rights and obligations of each investor.

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligation for the liabilities, relating to the arrangement. Where the Group acts as a joint operator, the Group recognises in relation to its interest in a joint operation: its assets, including its share of any assets held jointly; its liabilities, including its share of any 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; and its expenses, including its share of any expenses incurred jointly.

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. With regards to joint arrangements, where the Group acts as a joint venture, the Group recognises its interest in a joint venture as an investment and accounts for that investment using the equity method.

The effects of the change in accounting policies on consolidated balance sheet and consolidated statements of comprehensive income and cash flows are shown in note 5.24.

Associated undertakings

Associated undertakings are undertakings over which the Group has significant influence and that are neither a subsidiary nor an interest in a joint venture. Significant influence occurs when the Group has the power to participate in the financial and operating policy decisions of an entity but has no control or joint control over those policies. Associated undertakings are accounted for using the equity method. The group's share of its associates' post-acquisition profits or losses is recognised in the consolidated statement of comprehensive income, and its share of post-acquisition movements in other comprehensive income is recognised in other comprehensive income. Unrealised gains on transactions between the Group and its associated undertakings are eliminated to the extent of the Group's interest in the associated undertakings; unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The Group's interest in each associated undertaking is carried in the consolidated balance sheet at an amount that reflects cost, including the goodwill at acquisition, the Group's share of profit and losses and its share of postacquisition movements in reserves recognized in equity. Provisions are recorded for any impairment in value.

Recognition of losses under equity accounting is discontinued when the carrying amount of the investment in an associated undertaking reaches zero, unless the Group has incurred obligations or guaranteed obligations in respect of the associated undertaking.

5.24 Recent accounting pronouncements

Standards, Amendments or Interpretations effective in 2013

(a) Adoption of IFRS 11 "Joint Arrangements"

Under IFRS 11 joint arrangements are classified as either joint operations or joint ventures depending on the contractual rights and obligations each investor has rather than the legal structure of the joint arrangement. The Group has assessed the nature of its joint arrangements and determined them to be joint ventures, except for its investments in OAO Tomskneft VNK, Salym Petroleum Development N.V. and Blue Stream Pipeline company B.V., which were determined to be joint operations. The joint arrangements determined to be joint ventures will continue to be accounted for under the equity method of accounting. In accordance with the transition provisions of IFRS 11, the Group has applied the new policy for interests in joint operations. The Group derecognised the investments that were previously accounted for using the equity method and recognised its share of each of the assets and the liabilities in respect of the interest in the joint operations.

The Group measured the initial carrying amount of the assets and liabilities by disaggregating them from the carrying amount of the investment as of 1 January 2012 on the basis of the information used in applying the equity method.

Management Judgement and Estimates

RWE AG (31 December 2013)

Management judgements in the application of accounting policies

Management judgements are required in the application of accounting policies. In particular, this pertains to the following aspects:

- With regard to certain contracts, a decision must be made as to whether they are to be treated as derivatives or as so-called own-use contracts, and be accounted for as executory contracts.
- Financial assets must be allocated to the categories “Held to maturity investments”, “Loans and receivables”, “Financial assets available for sale”, and “Financial assets at fair value through profit or loss”.
- With regard to “Financial assets available for sale”, a decision must be made as to if and when reductions in value are to be recognised as impairments with an impact on income.
- With regard to assets held for sale, it must be determined if they can be sold in their current condition and if the sale of such is highly probable. If both conditions apply, the assets and any related liabilities must be reported and measured as “Assets held for sale” or “Liabilities held for sale”, respectively

Management estimates and judgements

Preparation of consolidated financial statements pursuant to IFRS requires assumptions and estimates to be made, which have an impact on the recognised value of the assets and liabilities carried on the balance sheet, on income and expenses and on the disclosure of contingent liabilities.

Amongst other things, these assumptions and estimates relate to the accounting and measurement of provisions. With regard to non-current provisions, the discount factor to be applied is an important estimate, in addition to the amount and timing of future cash flows. The discount factor for pension obligations is determined on the basis of yields on high quality, fixed-rate corporate bonds on the financial markets as of the balance-sheet date.

The impairment test for goodwill and non-current assets is based on certain assumptions pertaining to the future, which are regularly adjusted. Property, plant and equipment is tested for indications of impairment on each cut-off date.

Power plants are grouped together as a cash-generating unit if their production capacity and fuel needs are centrally managed as part of a portfolio, and it is not possible to ascribe individual contracts and cash flows to the specific power plants.

Upon first-time consolidation of an acquired company, the identifiable assets, liabilities and contingent liabilities are recognised at fair value. Determination of the fair value is based on valuation methods which require a projection of anticipated future cash flows.

Deferred tax assets are recognised if realisation of future tax benefits is probable. Actual future development of income for tax purposes and hence the realisability of deferred tax assets, however, may deviate from the estimation made when the deferred taxes are capitalised.

Further information on the assumptions and estimates upon which these consolidated financial statements are based can be found in the explanations of the individual items.

All assumptions and estimates are based on the circumstances and forecasts prevailing on the balance-sheet date. Furthermore, as of the balance-sheet date, realistic assessments of overall economic conditions in the sectors and regions in which RWE conducts operations are taken into consideration with regard to the prospective development of business. Actual amounts may deviate from the estimated amounts if the overall conditions develop differently than expected. In such cases, the assumptions, and, if necessary, the carrying amounts of the affected assets and liabilities are adjusted.

As of the date of preparation of the consolidated financial statements, it is not presumed that there will be any material changes compared to the assumptions and estimates.

OA0 Gazprom (31 December 2013)

CRITICAL JUDGMENTS AND ESTIMATES IN APPLYING ACCOUNTING POLICIES

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amount of assets and liabilities as well as disclosures. Management also makes certain judgments, apart from those involving estimations, in the process of applying the accounting policies. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Actual results may differ from our estimates, and our estimates can be revised in the future, either negatively or positively, depending upon the outcome or changes in expectations based on the facts surrounding each estimate.

Judgments that have the most significant effect on the amounts recognized in the consolidated financial statements and estimates that can cause a significant adjustment to the carrying amount of assets and liabilities within the next financial year are reported below.

6.1 Consolidation of subsidiaries

Management judgment is involved in the assessment of control and the consolidation of subsidiaries in the Group's consolidated financial statements.

6.2 Tax legislation and uncertain tax positions

Russian tax, currency and customs legislation is subject to varying interpretations (see Note 38).

The Group's uncertain tax positions (potential tax gains and losses) are reassessed by management at every balance sheet date. Liabilities are recorded for income tax positions that are determined by management based on the interpretation of current tax laws. Liabilities for penalties, interest and taxes other than profit tax are recognised based on management's best estimate of the expenditure required to settle tax obligations at the balance sheet date.

6.3 Assumptions to determine amount of provisions

Impairment provision for accounts receivable

The impairment provision for accounts receivable is based on the Group's assessment of the collectability and recoverable amount of specific customer accounts, being the present value of expected cash flows. If there is deterioration in a major customer's creditworthiness or actual defaults are higher or lower than the estimates, the actual results could differ from these estimates. The charges (and releases) for impairment of accounts receivable may be material (see Note 10).

Impairment of Property, plant and equipment and Goodwill

The estimation of forecasted cash flows for the purposes of impairment testing involves the application of a number of significant judgements and estimates to certain variables including volumes of production and extraction, prices on gas, oil, oil products, electrical power, operating costs, capital investment, hydrocarbon reserves estimates, and macroeconomic factors such as inflation and discount rates.

In addition, judgement is applied in determining the cash-generating units assessed for impairment. For the purposes of the goodwill impairment test, management considers gas production, transportation and distribution activities as part of one Gas cash-generating unit and monitors associated goodwill at this level. The pipelines that are part of the Gas cash-generating unit are utilized primarily for the Group activities and represent the only transit route for the gas produced. Operationally, the gas produced is transported through the Group's Russian and Belorussian pipelines and distributed to meet demands of customers in Russia and then in the Former Soviet Union and Europe and underground storage facilities. The interrelationship of these activities forming the Gas cash-generating unit provides the basis for capturing the benefits from synergies.

The value in use of assets or cash-generating units related to oil and gas operations are based on the cash flows expected from oil and gas production volumes, which include both proved reserves as well as certain volumes of those that are expected to constitute proved and probable reserves in the future. Impairment charges are disclosed in Note 12.

Accounting for provisions

Accounting for impairment includes provisions against capital construction projects, financial assets, other noncurrent assets and inventory obsolescence. Because of the Group's operating cycle, certain significant decisions about capital construction projects are made after the end of the calendar year. Accordingly, the Group typically has larger impairment charges or releases in the fourth quarter of the fiscal year as compared to other quarters.

6.4 Site restoration and environmental costs

Site restoration costs that may be incurred by the Group at the end of the operating life of certain Group's facilities and properties are recognized when the Group has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made. The cost is depreciated through the profit and loss of the consolidated statement of comprehensive income on a straight-line basis over the asset's productive life. Changes in the measurement of an existing site restoration obligation that result from changes in the estimated timing or amount of the outflows, or from changes in the discount rate adjust the cost of the related asset in the current period. IFRS prescribes the recording of liabilities for these costs. Estimating the amounts and timing of those obligations that should be recorded requires significant judgment. This judgment is based on cost and engineering studies using currently available technology and is based on current environmental regulations. Liabilities for site restoration are subject to change because of change in laws and regulations, and their interpretation.

6.5 Useful lives of Property, plant and equipment

The estimation of the useful life of an item of property, plant and equipment is a matter of management judgment based upon experience with similar assets. In determining the useful life of an asset, management considers the expected usage based on production and reserve estimates, estimated technical obsolescence, physical wear and tear and the physical environment in which the asset is operated. Changes in any of these conditions or estimates may result in adjustments to future depreciation rates.

Were the estimated useful lives to differ by 10% from management's estimates, the impact on depreciation for the year ended 31 December 2013 would be an increase by RR 46,462 or a decrease by RR 38,014 (2012: increase by RR 38,272 or decrease by RR 31,313).

Based on the terms included in the licenses and past experience, management believes hydrocarbon production licenses will be extended past their current expiration dates at insignificant additional costs. Because of the anticipated license extensions, the assets are depreciated over their useful lives beyond the end of the current license term.

6.6 Fair value estimation for financial instruments

The fair values of energy trading contracts, commodity futures and swaps are based on market quotes on measurement date (Level 1 in accordance with the valuation hierarchy). Customary valuation models are used to value financial instruments which are not traded in active markets. The fair values are based on inputs that are observable either directly or indirectly (Level 2 in accordance with the valuation hierarchy). Contracts that are valued based on non-observable market data belong to Level 3 in accordance with the valuation hierarchy. Management's best estimates based on internally developed models are used for the valuation. Where the valuation technique employed incorporates significant unobservable input data such as these long-term price assumptions, contracts have been categorised as Level 3 in accordance with the valuation hierarchy (see Note 40).

The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

6.7 Fair value estimation for acquisitions

In accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values of property, plant and equipment and identifiable intangible assets.

The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

6.8 Accounting for plan assets and pension liabilities

Pension plan liabilities are estimated using actuarial techniques and assumptions as disclosed in Note 24. Actual results may differ from the estimates, and the Group's estimates can be revised in the future based on changes in economic and financial conditions. In addition, certain plan assets included in NPF Gazfund are estimated using the fair value estimation techniques. Management makes judgments with respect to the selection of valuation model applied, the amount and timing of cash flows forecasts or other assumptions such as discount rates. The recognition of plan assets is limited by the estimated present value of future benefits which are available to the Group in relation to this plan. These benefits are determined using actuarial techniques and assumptions. The impact of the change in the limitation of the plan assets in accordance with IAS 19 is disclosed in Note 24. The value of plan assets and the limit are subject to revision in the future.

6.9 Joint Arrangements

Upon adopting of IFRS 11 the Group applied judgement when assessing whether its joint arrangements represent a joint operation or a joint venture. The Group determined the type of joint arrangement in which it is involved by considering its rights and obligations arising from the arrangement including the assessment of the structure and legal form of the arrangement, the terms agreed by the parties in the contractual arrangement and, when relevant, other facts and circumstances.

Concession Arrangements

RWE AG (31 December 2013)

In the fields of electricity, gas and water supply, there are a number of easement agreements and concession contracts between RWE Group companies and the governmental authorities in the areas we supply.

Easement agreements are used in the electricity and gas business to regulate the use of public rights of way for laying and operating lines for public energy supply. These agreements are generally limited to a term of 20 years. After expiry, there is a legal obligation to transfer ownership of the local distribution facilities to the new operator, for appropriate compensation.

Water concession agreements contain provisions for the right and obligation to provide water and wastewater services, operate the associated infrastructure, such as water utility plants, as well as to implement capital expenditure. Concessions in the water business generally have terms of up to 25 years.

Électricité de France SA (31 December 2013)

1.3.13 Concession agreements

1.3.13.1 Accounting treatment

The accounting treatment of public and private agreements depends on the nature of the agreements and their specific contractual features.

For most of its concessions, the Group considers that in substance the grantors do not have the characteristic features of control over infrastructures as defined in IFRIC 12.

1.3.13.2 French concessions

In France, the Group is the operator for three types of public service concessions:

- public electricity distribution concessions in which the grantors are local authorities (municipalities or syndicated municipalities);
- hydropower concessions with the State as grantor;
- the public transmission network operated under concession from the State.

1.3.13.2.1 Public electricity distribution concessions

General background

- Since the enactment of the French Law of 8 April 1946, the EDF group has by law been the sole operator for the main public distribution concessions in France.

The accounting treatment of concessions is based on the concession agreements, with particular reference to their special clauses. It takes into consideration the possibility that the EDF group may one day lose its status as the sole authorised State concession operator.

These agreements generally cover terms of between 20 and 30 years, and use standard concession rules deriving from the 1992 Framework Contract (updated in 2007) negotiated with the National Federation of Licensing Authorities (Fédération Nationale des Collectivités Concédantes et Régies – FNCCR) and approved by the public authorities.

- Recognition of assets as property, plant and equipment operated under French public electricity distribution concessions

All assets used by the EDF group in public electricity distribution concessions in France, whether they are owned by the grantor or the operator, are reported together on a specific line in the balance sheet assets at acquisition cost, or their estimated value at the transfer date when supplied by the grantor.

1.3.13.2.2 Hydropower concessions

Hydropower concessions in France follow standard rules approved by decree. Assets attributed to the hydropower concessions comprise hydropower generation equipment (dams, pipes, turbines, etc) and, in the case of recently-renewed concessions, electricity generation and switching facilities (alternators, etc).

Assets used in these concessions are recorded under “Property, plant and equipment operated under concessions for other activities” at acquisition cost. As a result of changes in the regulations following removal of the outgoing operator’s preferential right when a concession is renewed, the Group has shortened the depreciation periods used for certain assets.

1.3.13.2.3 Public transmission concession

Under French law, assets assigned to the public transmission concession belong to RTE Réseau de Transport d’Électricité (RTE). Following the Group’s loss of control over RTE from 31 December 2010, these assets are included in calculating the equity value of RTE in the consolidated balance sheet.

1.3.13.2.4 Foreign concessions

Foreign concessions are governed by a range of contracts and national laws. Most assets operated under foreign concessions are recorded under “Property, plant and equipment operated under concessions for other activities”. Foreign concessions essentially concern Edison in Italy, which operates hydrocarbon generation sites, gas storage sites, local gas distribution networks and hydropower generating plants under concessions. Edison owns all the assets except for some items of property, plant and equipment on the hydropower generation sites, which will be returned to the grantor for nil consideration or with an indemnity when the concession ends. In compliance with IFRIC 12, certain concession agreements are recorded as intangible assets.

Hydropower generation assets which will be returned for nil consideration at the end of the concession are depreciated over the duration of the concession. Hydrocarbon generation sites are recorded in compliance with the rules applicable to the sector (see note 1.3.11).

Nuclear Fuel

IBERDROLA, S.A. (31 December 2013)

The IBERDROLA Group measures its nuclear fuel stocks on the basis of the costs actually incurred in acquiring and subsequently processing the fuel.

Nuclear fuel costs include the finance charges accrued during construction, calculated as indicated in Note 4.g. The amounts capitalised in this connection in 2013 and 2012 were EUR 1,730 thousand and EUR 1,406 thousand, respectively (Notes 15 and 40).

The nuclear fuel consumed is recognised under "Procurements" in the Consolidated income statement from when the fuel loaded into the reactor starts to be used, based on the cost of the fuel and the degree of burning in each reporting period. The nuclear fuel stocks consumed in 2013 and 2012 amounted to EUR 120,738 thousand and EUR 118,606 thousand, respectively (Note 15).

GDF SUEZ SA (31 December 2013)

Inventories are measured at the lower of cost and net realizable value. Net realizable value corresponds to the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

The cost of inventories is determined based on the first-in, first-out method or the weighted average cost formula.

Nuclear fuel purchased is consumed in the process of producing electricity over a number of years. The consumption of this nuclear fuel inventory is recorded based on estimates of the quantity of electricity produced per unit of fuel.

Financial Instruments

Centrica plc (31 December 2012)

Financial Instruments

Financial assets and financial liabilities are recognised in the Group Balance Sheet when the Group becomes a party to the contractual provisions of the instrument. Financial assets are de-recognised when the Group no longer has the rights to cash flows, the risks and rewards of ownership or control of the asset. Financial liabilities are de-recognised when the obligation under the liability is discharged, cancelled or expires.

(a) Trade receivables

Trade receivables are initially recognised at fair value, which is usually original invoice amount and are subsequently held at amortised cost less an allowance for any uncollectible amounts. Provision is made when there is objective evidence that the Group may not be able to collect the trade receivable. Balances are written off when recoverability is assessed as being remote. If collection is due in one year or less receivables are classified as current assets. If not they are presented as non-current assets.

(b) Trade payables

Trade payables are initially recognised at fair value, which is usually original invoice amount and are subsequently held at amortised cost. If payment is due within one year or less payables are classified as current liabilities. If not, they are presented as non-current liabilities.

(c) Share capital

Ordinary shares are classified as equity. Incremental costs directly attributable to the issue of new shares are shown in equity as a deduction from the proceeds received. Own equity instruments that are re-acquired (treasury or own shares) are deducted from equity. No gain or loss is recognised in the Group Income Statement on the purchase, sale, issue or cancellation of the Group's own equity instruments.

(d) Cash and cash equivalents

Cash and cash equivalents comprise cash in hand and current balances with banks and similar institutions, which are readily convertible to known amounts of cash and which are subject to insignificant risk of changes in value and have an original maturity of three months or less.

For the purpose of the Group Cash Flow Statement, cash and cash equivalents consist of cash and cash equivalents as defined above, net of outstanding bank overdrafts.

(e) Interest-bearing loans and other borrowings

All interest-bearing loans and other borrowings with banks and similar institutions are initially recognised at fair value net of directly attributable transaction costs. After initial recognition, interest-bearing loans and other borrowings are subsequently measured at amortised cost using the effective interest method, except when they are the hedged item in an effective fair value hedge relationship where the carrying value is also adjusted to reflect the fair value movements associated with the hedged risks. Such fair value movements are recognised in the Group Income Statement. Amortised cost is calculated by taking into account any issue costs, discount or premium.

(f) Available-for-sale financial assets

Available-for-sale financial assets are those non-derivative financial assets that are designated as available-for-sale, which are recognised initially at fair value within the Group Balance Sheet. Available-for-sale financial assets are re-measured subsequently at fair value with gains and losses arising from changes in fair value recognised directly in equity and presented in the Group Statement of Comprehensive Income, until the asset is disposed of or is determined to be impaired, at which time the cumulative gain or loss previously recognised in equity is included in the Group Income Statement for the period. Accrued interest or dividends arising on available-for-sale financial assets are recognised in the Group Income Statement.

At each Balance Sheet date the Group assesses whether there is objective evidence that available-for-sale financial assets are impaired. If any such evidence exists, cumulative losses recognised in equity are removed from equity and recognised in the Group Income Statement. The cumulative loss removed from equity represents the difference between the acquisition cost and current fair value, less any impairment loss on that financial asset previously recognised in the Group Income Statement. Impairment losses recognised in the Group Income Statement for equity investments classified as available-for-sale are not subsequently reversed through the Group Income Statement.

Impairment losses recognised in the Group Income Statement for debt instruments classified as available-for-sale are subsequently reversed if an increase in the fair value of the instrument can be objectively related to an event occurring after the recognition of the impairment loss.

(g) Financial assets at fair value through profit or loss

The Group holds investments in gilts which it designates as fair value through profit or loss. Investments are measured at fair value on initial recognition and are re-measured to fair value in each subsequent reporting period. Gains and losses arising from changes in fair value are recognised in the Group Income Statement within interest income or interest expense.

(h) Derivative financial instruments

The Group routinely enters into sale and purchase transactions for physical delivery of gas, power and oil. A portion of these transactions take the form of contracts that were entered into and continue to be held for the purpose of receipt or delivery of the physical commodity in accordance with the Group's expected sale, purchase or usage requirements (own use), and are not within the scope of IAS 39. The assessment of whether a contract is deemed to be 'own use' is conducted on a Group basis without reference to underlying book structures, business units or legal entities.

Certain purchase and sales contracts for the physical delivery of gas, power and oil are within the scope of IAS 39 due to the fact that they net settle or contain written options. Such contracts are accounted for as derivatives under IAS 39 and are recognised in the Group Balance Sheet at fair value. Gains and losses arising from changes in fair value on derivatives that do not qualify for hedge accounting are taken directly to the Group Income Statement for the year.

The Group uses a range of derivatives for both trading and to hedge exposures to financial risks, such as interest rate, foreign exchange and energy price risks, arising in the normal course of business. The use of derivative financial instruments is governed by the Group's policies which are approved by the Board of Directors. Further detail on the Group's risk management policies is included within the Strategic Report – Principal Risks and Uncertainties on pages 42 to 48 and in note S3.

The accounting treatment for derivatives is dependent on whether they are entered into for trading or hedging purposes. A derivative instrument is considered to be used for hedging purposes when it alters the risk profile of an underlying exposure of the Group in line with the Group's risk management policies and is in accordance with established guidelines, which require the hedging relationship to be documented at its inception, ensure that the derivative is highly effective in achieving its objective, and require that its effectiveness can be reliably measured. The Group also holds derivatives which are not designated as hedges and are held for trading.

All derivatives are recognised at fair value on the date on which the derivative is entered into and are re-measured to fair value at each reporting date. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative. Derivative assets and derivative liabilities are offset and presented on a net basis only when both a legal right of set-off exists and the intention to net settle the derivative contracts is present.

The Group enters into certain energy derivative contracts covering periods for which observable market data does not exist. The fair value of such derivatives is estimated by reference in part to published price quotations from active markets, to the extent that such observable market data exists, and in part by using valuation techniques, whose inputs include data which is not based on or derived from observable markets. Where the fair value at initial recognition for such contracts differs from the transaction price, a fair value gain or fair value loss will arise. This is referred to as a day-one gain or day-one loss. Such gains and losses are deferred (not recognised) and amortised to the Group Income Statement based on volumes purchased or delivered over the contractual period until such time observable market data becomes available. When observable market data becomes available, any remaining deferred day-one gains or losses are recognised within the Group Income Statement. Recognition of the gains or losses resulting from changes in fair value depends on the purpose for issuing or holding the derivative. For derivatives that do not qualify for hedge accounting, any gains or losses arising from changes in fair value are taken directly to the Group Income Statement and are included within gross profit or interest income and interest expense. Gains and losses arising on derivatives entered into for speculative energy trading purposes are presented on a net basis within revenue.

Embedded derivatives: derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contracts and the host contracts are not carried at fair value, with gains or losses reported in the Group Income Statement. The closely-related nature of embedded derivatives is reassessed when there is a change in the terms of the contract which significantly modifies the future cash flows under the contract. Where a contract contains one or more embedded derivatives, and providing that the embedded derivative significantly modifies the cash flows under the contract, the option to fair value the entire contract may be taken and the contract will be recognised at fair value with changes in fair value recognised in the Group Income Statement.

(i) Hedge accounting

For the purposes of hedge accounting, hedges are classified as either fair value hedges or cash flow hedges. Note S5 details the Group's accounting policies in relation to derivatives qualifying for hedge accounting under IAS 39.

Appendix B – IFRS/US GAAP differences

This section summarises the differences between IFRS and US GAAP that are particularly relevant to utility entities. These differences relate to: depreciation, decommissioning obligations, impairment, regulatory assets and financial instruments.

Property, plant and equipment – components

Issue	IFRS	US GAAP
Components of property, plant and equipment	Follows a component approach to depreciation. Significant parts (components) of an item of property, plant and equipment are depreciated separately if they have different useful lives.	Does not require the component approach to depreciation; however, it is sometimes followed as a matter of industry practice. The use of composite (group) depreciation is also commonly used.

Property, plant and equipment – decommissioning obligations

Issue	IFRS	US GAAP
Measurement of liability	<p>A decommissioning liability is measured initially at the best estimate of the expenditure required to settle the obligation.</p> <p>Risks associated with the liability are reflected in the cash flows or in the discount rate.</p> <p>The decommissioning liability is remeasured each reporting period by updating the discount rate.</p> <p>The fact that an asset to be decommissioned has an indeterminate life does not remove the need to measure the decommissioning obligation, but the effect of discounting will have a greater impact on the measurement of the liability.</p>	<p>A decommissioning liability (asset retirement obligation) is recorded initially at fair value if a reasonable estimate of fair value can be made. An expected present value technique based on expected cash flows to perform the decommissioning activities is usually the only appropriate technique to apply.</p> <p>Risks associated with the performance of the activities are reflected in the cash flows. Credit risk is reflected in the discount rate.</p> <p>An asset retirement obligation is remeasured if and when there is a change in the amount or timing of cash flows.</p> <ul style="list-style-type: none"> • Downward revisions to undiscounted cash flows are discounted using the credit-adjusted, risk-free rate used when the liability was originally recognised. • Upward revisions to undiscounted cash flows are discounted using the credit-adjusted, risk-free rate at the time of the revision. <p>A decommissioning liability does not need to be recognised for assets with indeterminate lives if there is insufficient information available to estimate fair value.</p>
Recognition of decommissioning asset	<p>The adjustment to property, plant and equipment associated with the decommissioning liability forms part of the asset to be decommissioned.</p>	<p>The adjustment to property, plant and equipment associated with the decommissioning liability is recognised by increasing the carrying value of the asset to be decommissioned. The asset retirement cost can be subsumed as part of the overall asset or can be tracked as a separate unit of account.</p>

Property, plant and equipment – impairment

Issue	IFRS	US GAAP
Impairment test triggers	Assets or groups of assets (cash generating units) are tested for impairment when indicators of impairment are present.	Long-lived assets are tested for impairment when events or circumstances indicate that the carrying value might not be recoverable. The carrying value is not recoverable if it exceeds the sum of the undiscounted cash flows based on the entity's planned use.
Measurement of impairment	Impairment is measured as the excess of the asset's carrying amount over its recoverable amount. The recoverable amount is the higher of its value in use and fair value less costs to sell. Value in use represents the future cash flows discounted to present value by using a pre-tax, market-determined rate that reflects the current assessment of the time value of money and the risks specific to the asset for which the cash flow estimates have not been adjusted. Fair value less cost to sell represents the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties less the costs of disposal.	Impairment is measured as the excess of the asset's carrying amount over its fair value. Fair value is defined as the price that would be received to sell the asset in an orderly transaction between market participants at the measurement date.
Reversal of impairment charge	If certain criteria are met, the reversal of impairments, other than those relating to goodwill, is permitted.	The reversal of impairments is prohibited.

Arrangements that may contain a lease

Issue	IFRS	US GAAP
Retrospective application	<p>Arrangements that convey the right to use an asset in return for a payment or series of payments are required to be accounted for as leases if certain conditions are met. This requirement applies even if the contract does not take the legal form of a lease.</p> <p>The IFRS guidance that requires this analysis, IFRIC 4, requires all existing arrangements to be analysed on adoption (that is, no grandfathering of existing arrangements).</p>	<p>Similar to IFRS, except that the US GAAP guidance, EITF 01-8 (codified into ASC 840), was applicable only to new arrangements entered into (or modifications made to existing arrangements) after the effective date (that is, grandfathering of existing arrangements was provided).</p>

Regulatory assets and liabilities

Issue	IFRS	US GAAP
Regulatory assets and liabilities	<p>IFRS does not contain specific guidance for the recognition of regulatory assets and liabilities. Assets and liabilities arising from rate-regulated activities that meet the definition of an asset or liability pursuant to existing IFRSs or under the conceptual framework should be recognised.</p>	<p>US GAAP (ASC 980) contains guidance for the recognition of regulatory assets and liabilities, in appropriate circumstances, by regulated entities that meet specified requirements for recognition.</p>

Business combinations

Issue	IFRS	US GAAP
Fair values on acquisition	<p>IFRS and US GAAP are largely converged. Most acquired assets and liabilities are generally required to be recorded at fair value upon acquisition, with some detailed differences from US GAAP.</p> <p>Fair value is the amount for which an asset could be exchanged or a liability settled between knowledgeable, willing parties in an arm's length transaction. IFRS does not specifically refer to either an entry or exit price (when IFRS 13 is effective, the fair value definition will be converged with US GAAP).</p>	<p>Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date.</p>
Contingent consideration	<p>Contingent consideration is recognised initially at fair value as either an asset, liability or equity according to the applicable IFRS guidance.</p>	<p>Contingent consideration is recognised initially at fair value as either an asset, liability or equity according to the applicable US GAAP guidance.</p>
Non-controlling interests	<p>Entities have an option, on a transaction-by-transaction basis, to measure non-controlling interests at their proportion of the fair value of the identifiable net assets or at full fair value. This option applies only to instruments that represent present ownership interests and entitle their holders to a proportionate share of the net assets in the event of liquidation. No gains or losses are recognised in earnings for transactions between the parent company and the non-controlling interests, unless control is lost.</p>	<p>Non-controlling interests are measured at fair value. No gains or losses are recognised in earnings for transactions between the parent company and the non-controlling interests, unless control is lost.</p>
Goodwill	<p>Goodwill is allocated to a CGU or group of CGUs, as defined within the guidance. Goodwill impairment testing is performed under a one-step approach: the recoverable amount of the CGU or group of CGUs is compared with its carrying amount. Any impairment amount is recognised in operating results as the excess of the carrying amount over the recoverable amount.</p>	<p>Goodwill impairment testing is performed using a two-step approach to impairment. The first step comprises determining whether the reporting unit is impaired; the second step is the measurement of the impairment.</p>

Concession arrangements

Issue	IFRS	US GAAP
Identification and classification of concession arrangements	Public-to-private service concession arrangements that meet certain conditions must be analysed to determine whether the concession represents a financial asset or an intangible asset.	No equivalent guidance specifically addressing concession arrangements.

Financial instruments and trading and risk management

IFRS and US GAAP take broadly consistent approaches to the accounting for financial instruments; however, there are many detailed differences. IFRS and US GAAP define financial assets and financial liabilities in similar ways.

Selected differences between IFRS and US GAAP are summarised below.

Issue	IFRS	US GAAP
Definition of a derivative	<p>A derivative is a financial instrument that:</p> <ul style="list-style-type: none"> • changes value in response to a specified variable or underlying rate (for example, commodity index or interest rate); • requires no or little net investment; and • is settled at a future date. 	<p>A derivative instrument:</p> <ul style="list-style-type: none"> • includes an underlying and a notional amount; • requires no or little net investment; and • requires or permits net settlement (either within the contract, through a market mechanism, or by delivery of an asset that is readily convertible to cash). <p>Because of differences in the definition, some contracts, either in their entirety or partially, contain derivatives under IFRS but not US GAAP.</p>

Financial instruments and trading and risk management

Issue	IFRS	US GAAP
Separation of embedded derivatives	<p>Derivatives embedded in hybrid contracts are separated where:</p> <ul style="list-style-type: none"> • the economic characteristics and risks of the embedded derivatives are not closely related to the economic characteristics and risks of the host contract; • a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and • the hybrid instrument is not measured at fair value through profit or loss. <p>Reassessment of whether an embedded derivative needs to be separated is permitted only where there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required under the contract.</p> <p>A host contract from which an embedded derivative has been separated qualifies for the own use exemption if the own use criteria are met for the host.</p>	<p>The separation of embedded derivatives is similar to IFRS, although there are some detailed differences in evaluating whether the embedded derivative is ‘clearly and closely related’. The ‘clearly and closely related’ is a one-time evaluation.</p> <p>If a hybrid instrument contains an embedded derivative that is not clearly and closely related to the host contract at inception, but is not required to be bifurcated (for example, it does not meet the definition of a derivative on a stand-alone basis), the embedded derivative is continually reassessed to determine if it subsequently meets the definition of a derivative and bifurcation is required.</p>

Financial instruments and trading and risk management

Issue	IFRS	US GAAP
<p>Own use exemption compared to normal purchase and normal sale exemption</p>	<p>Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument are accounted for as financial instruments, unless the contract was entered into and continues to be held for the purpose of the physical receipt or delivery of the non-financial item in accordance with the entity's expected purchase, sale or usage requirements.</p> <p>Application of the own use exemption is a requirement, not an election.</p>	<p>Contracts that qualify and are designated as normal purchases and normal sales are not accounted for as derivatives. The conditions under which the normal purchase and normal sales exemption is available are similar to the own use exemption under IFRS, although there are some detailed differences.</p> <p>Application of the normal purchases and normal sales exemption must be elected by the entity in order to be applied.</p> <p>If there is a pricing provision in the contract that is not clearly and closely related to the underlying item being delivered, the contract does not qualify for the exemption.</p>
<p>Transaction costs</p>	<p>Transaction costs that are directly attributable to the acquisition or issuance of a financial asset or financial liability are added to its fair value on initial recognition, unless the asset or liability is measured subsequently at fair value, with changes in fair value recognised in profit or loss.</p>	<p>Transaction costs are specifically excluded from a fair value measurement.</p>

Financial instruments and trading and risk management

Issue	IFRS	US GAAP
Subsequent measurement	<p>Subsequent measurement depends on the classification of the financial asset or financial liability.</p> <p>Certain classes of financial asset or financial liability are measured subsequently at amortised cost using the effective-interest method; and others, including derivative financial instruments, are measured at fair value through profit or loss.</p> <p>The available-for-sale (AFS) class of financial assets is measured subsequently at fair value through equity (other comprehensive income).</p> <p>These general classes of financial asset and financial liability are used under both IFRS and US GAAP, but the classification criteria differ in certain respects. The issuance of IFRS 9 (see Chapter 3, Future developments – Standards issued and not yet effective) has resulted in further differences between the accounting for financial instruments between IFRS and US GAAP.</p>	<p>The general classes of financial asset and financial liability are used under both IFRS and US GAAP, but the classification criteria differ in certain respects.</p> <p>The issuance of IFRS 9 (see Chapter 3, Future developments – Standards issued and not yet effective) has resulted in further differences between the accounting for financial instruments between IFRS and US GAAP.</p>
Offsetting contracts	<p>A practice of entering into offsetting contracts to buy and sell a commodity is considered to be a practice of net settlement. All similar contracts must be accounted for as derivatives.</p>	<p>Similar to IFRS, except that power purchase or sales agreements that meet the definition of a capacity contract qualify to be treated as normal purchases and normal sales, provided certain criteria are met.</p>

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