

Financial reporting in the power and utilities industry

International Financial
Reporting Standards

2nd edition



Foreword

International Financial Reporting Standards (IFRS) provide the basis for company reporting in an increasing number of countries around the world. Over 100 countries either use or are adopting IFRS reporting. The pace of standard-setting from the International Accounting Standards Board (IASB) has been intense in recent years, with a constant flow of changes for companies to keep up with.

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 utilities companies. We draw on our considerable experience of helping 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 power and utilities companies' activities.

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 and commitment to helping companies in the sector report effectively. For more information or assistance, please do not hesitate to contact your local office or one of our specialist power and utilities partners.



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September 2011



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Introduction

What is the focus of this publication?

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

The need for this publication has arisen due to the following factors:

- The adoption of IFRS by power and utility entities across a number of jurisdictions, with overwhelming acceptance that applying IFRS in this industry will be a continual challenge
- Ongoing transition projects in a number of other jurisdictions, from which companies can draw upon the existing interpretations of the industry

Who should use this publication?

This publication is intended for:

- Executives and financial managers in the power and utility industries who are often faced with alternative accounting practices
- Investors and other users of power and utility industry financial statements, so they can identify some of the accounting practices adopted to reflect unusual features unique to the industry
- Accounting bodies, standard-setting agencies and governments throughout the world interested in accounting and reporting practices and responsible for establishing financial reporting requirements

What is included?

This publication includes a discussion of issues that we believe are of financial reporting interest due to their particular relevance to power and utility entities and/or historical varying international practice.

We focus our discussion not only on how the transition to IFRS has affected the power and utility industry, but also on how the industry is dealing with the following factors:

- Significant growth in corporate acquisition activity
- Increased globalisation
- Change in political landscape towards sustainability and renewable energy often leading towards more regulation
- Continued increase in its exposure to sophisticated financial instruments and transactions
- An increased focus on environmental and restoration liabilities

PwC experience

This publication is based on the experience gained from the worldwide leadership position of PwC in the power and utility industry. This leadership position 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 & Utilities value chain and significant accounting issues

1 Power & Utilities value chain and significant accounting issues

1.1 Overview

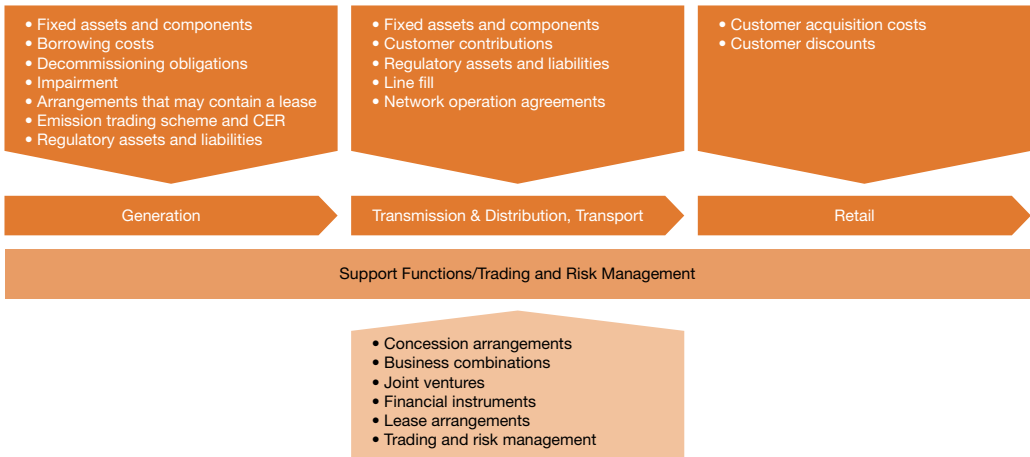
A traditional integrated power entity (utility) generates electricity and sends it around the country or region via high-voltage transmission lines, finally delivering it to customers through a retail distribution network. Some utilities also or exclusively transport water and/or gas. As the industry 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 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 may be split by regulation into generation, transmission, distribution and retail businesses. Competition may 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 may see the incumbent operator forced to grant other suppliers access to its network. 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, phone, water and internet as well as power.

The power and utility 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 following 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, as many assets include components with a shorter useful life than the asset as a whole.

Identification of 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, as the detailed recordkeeping needed for componentisation may not have been required to comply with national generally accepted accounting principles (GAAP). This can particularly be an issue for older power plants. However, some regulators may 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 more severe than that of the other portions of the larger asset.

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.

Depreciation of components

All components should be depreciated to their recoverable amount over their useful lives, which may 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, provided 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 may 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 get ready 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/or 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 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 $((100 \text{ million} + 350 \text{ million} + 600 \text{ million} + 850 \text{ million})/4)$.

The entity has not taken out any specific borrowings to finance the construction of the plant, but 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 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:

	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

Weighted-average borrowings during period:

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

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

The capitalisation rate, therefore, reflects the weighted-average cost of borrowings for the 4-month period that the asset was under construction. On an annualised basis 3.756% gives a capitalisation rate of 11.268% per annum, which is what would be expected on the borrowings profile.

$$\begin{aligned} \text{Therefore, the total amount of borrowing costs to be} \\ \text{capitalised is the weighted-average carrying amount} \\ \text{of asset} \times \text{capitalisation rate} \\ &= \text{C}475 \text{ million} \times 11.268\% \times 4/12 \\ &= \text{C}17,841,000 \end{aligned}$$

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.

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.

A utility often contracts for a power plant on a turnkey basis. Down payments will often have to be paid by the utility, for example, 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 (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.

Often utilities hedge borrowings. The effects of cash flow or fair value hedge relationships on interest for a specific project borrowing should also be capitalised. While this is not addressed specifically by the standard, the principles of IAS 39 are such that the hedging relationship modifies the borrowing costs of the utility related to the specific debt. We believe therefore that entities should take into account the effects of IAS 39 designated hedge accounting relationships for borrowing costs. 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 may be required by law, the terms of operating licences or an entity's stated policy and past practice. An entity that promises to remediate damage, even when there is no legal requirement, may have created a constructive obligation and thus a liability under IFRS. There may also be environmental clean-up obligations for contamination of land that arises during the

operating life of a power plant or other installation. The associated costs of remediation/restoration can be significant. The accounting treatment for decommissioning costs is therefore critical.

Decommissioning provisions

A provision is recognised when an obligation exists to 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 at the time 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 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: generally time-based for a power station.

Provisions for decommissioning and restoration are recognised even if the decommissioning is not expected to be performed for a long time, for example 80 to 100 years. The effect of the time to expected decommissioning 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. Different decommissioning obligations, naturally, have different inherent risks, for example different uncertainties associated with the methods, the costs and the timing of decommissioning. The risks specific to the liability can be reflected 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 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. The adjustments to the asset are restricted, however. 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 may not be fully recoverable.

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

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 may also identify impairment indicators on a regional, country or other asset grouping basis, reflective of how they manage their business. Once an impairment indicator has been identified, the impairment test must be performed at the individual CGU level, even if the indicator was identified at a regional level.

Cash-generating units

A CGU is the smallest group of assets that generates cash inflows largely independent of other assets or groups of assets. 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), an entity considers various factors, including how management monitors the entity's operations or how management makes decisions about continuing or disposing of the entity's assets and operations.

Calculation of recoverable amount

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

Fair value less costs to sell (FVLCTS)

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

The projected cash flows for FVLCTS therefore include the assumptions that a potential purchaser would include in determining the price of the asset. Thus,

industry expectations for the development of the asset may be taken into account, which may not be permitted under VIU. However, the assumptions and resulting value must be based on recent market data and transactions.

Post-tax cash flows are used when calculating FVLCTS using a discounted cash flow model. The discount rate applied in FVLCTS 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 and must exclude any plans to enhance the asset or its output in the future, but includes expenditure necessary to maintain the current performance of the asset. The VIU cash flows for assets 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 the most difficult element of the impairment test, as pre-tax rates are not available in the marketplace and arriving at the correct pre-tax rate is a complex mathematical exercise. Grossing up the post-tax rate does not give the correct answer unless no deferred tax is involved.

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 may 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 may contain a lease

Accounting in this area will change due to 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 may 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. If lease accounting is inevitable, investors sometimes prefer operating lease accounting.

Power purchase agreements

It can be difficult to determine whether the power purchase agreement contains a lease. The purchaser may 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 (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 (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:

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 not 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 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 MWhs in the first month, the price is C42/MWh (C40/MWh energy charge plus C2/MWh allocated capacity charge). However, if the plant produces only 10,000 MWhs, the price is C43/MWh.

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.

Wind farm contract:

- For 100% of the output of the wind farm
- 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
- Pricing escalates annually based on annual changes in the consumer price index

The developer and owner of the wind farm agrees to sell 100% of the output of the wind farm to a single

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 (e.g., the wind, sun or rain/snowfall). The following example illustrates this concept:

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 site 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 IFRIC 4.9c. 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 a renewable energy certificate per MWh of renewable energy generated to demonstrate that the electricity has been procured from renewable sources.

The determination of whether renewable energy certificates are “output or other utility” may impact the evaluation of whether a power purchase agreement contains a lease, particularly when 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 Emission trading schemes and certified emission reductions

The ratification of the Kyoto Protocol by the EU required total emissions of greenhouse gases within the EU member states to fall to 92% of their 1990 levels in the period between 2008 and 2012. Under the scheme, EU member states have set limits on carbon dioxide emissions from energy-intensive companies. The scheme works on a “cap and trade” basis, and each 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, for example, the New South Wales Greenhouse Gas Abatement Scheme, the Regional Greenhouse Gas Initiative and Western Climate Initiative in the United States.

Accounting for emission 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
- 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 IFRS standards are met. Several approaches have emerged in practice under IFRS. The scheme can result in the recognition of assets (allowances), expense of emissions, a liability (obligation to submit allowances) and potentially a government grant.

The allowances are intangible assets – 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 as 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 that the carrying amount of the allowances is restated to fair value at each balance sheet date, with changes to fair value recognised directly in equity, except for impairment, which is recognised in the income statement.

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

Certified emission reductions

Another scheme under the Kyoto Protocol is in place for fast-growing countries and countries in transition that are not subject to a Kyoto target on emissions reduction. Entities in these countries can generate certified emission reductions (CERs). 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 then 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 (i.e., 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 (i.e., IAS 2 for inventory, IAS 38 for intangible assets, IFRS 5 for non-current assets held for sale)

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. Many individual components may not be significant. A practical approach to identifying components is to consider the entity's mid-/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 identification of components based on repairs and maintenance schedules and planned major renovations or replacements.

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.

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 as the normal fixed asset accounting and depreciation requirements apply. This may be a significant change for network companies and introduces some application challenges.

An entity with a history of expensing all current expenditure may 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, then, provided recognition criteria are met (cost can be reliably measured and future economic benefits are probable), these costs should be capitalised. 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 may 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 may extend this life, but ultimately the asset will need to be replaced.

A residual value must be determined for all significant components. This value in many cases is likely to be scrap only or nil, since 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 may be significant. This is likely when the customer is located far from the network or when the volume of the utility that will be purchased requires substantial equipment. An example may be 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 question is 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 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 may be 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 may be 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 standalone value to the customer. If the network entity concludes that the connection service does not represent standalone value, it defers revenue over the period of the ongoing access service (or 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 for customers who have not transferred an asset. When 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 customers transferring assets to the entity pay the same price for goods or services as those that do not, management may 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 may be received from several of these. However, when major connection equipment is constructed for the sole benefit of one customer, consideration should be given to whether the equipment has, in substance, 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. 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 the recovery of 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.

In July 2009, the IASB released an exposure draft, *Rate-regulated Activities*, which would allow for the recognition of regulatory assets and liabilities for reporting entities within its scope. The project was not completed due to resource constraints. However, the IASB has suggested possible ways forward, including a short- or medium-term project, or, alternatively, consideration of rate-regulated activities as part of a broader intangible asset project. Furthermore, the IASB has included rate-regulated activities as a project suggestion in its July 2011 Agenda Consultation. Reporting entities should continue to monitor the activities of the IASB in this area.

1.3.4 Line fill and cushion gas

Some items of property, plant and equipment, such as pipelines and gas storage, require a certain minimum level of product to be maintained in them in order for them to operate efficiently. This product is usually classified as part of the property, plant and equipment 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 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 B’s management account for the cushion gas as PPE or as inventory?

Entity B’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 IAS 16.43. However, if the cushion gas is recoverable in full when the storage facility is decommissioned, then 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 IAS 16.68. 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 oil inventories

Oil 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 oil product using the market price for oil at the balance sheet date.

Movements in the oil price after the balance sheet date typically reflect changes in the market conditions after that date and therefore should not be reflected in the calculation of net realisable value.

1.3.6 Network operation arrangements

Rights to use public ground for constructing and operating electricity grids are often limited in time. Municipalities may decide to not prolong these rights once they have expired, but operate the grids on their

own or enter into co-operations with network operating companies or other municipalities. The arrangements may 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
- 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 chapter 1.5.1.

1.4 Retail

1.4.1 Customer acquisition costs

Deregulation of markets and the introduction of competition often provides 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.

However, 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.

1.4.2 Customer discounts

Utility entities may offer discounts and other incentives to customers to encourage them to sign up to certain tariffs or payment plans. The costs associated with these programmes need to be identified carefully to ensure that they are appropriately separated from the sales revenue. For example, when customers receive a discount for paying monthly compared with other customers who pay quarterly, the sales revenue should be separated from the finance income that is embedded in the price charged to the customers who pay quarterly.

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 arrangements 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 may construct the infrastructure, maintain and provide the service to the public. The provider may be paid for its services in different ways. Many concessions require that the related infrastructure assets are returned or transferred to the government at the end of the concession.

IFRIC 12 applies to arrangements where the grantor (the government or its agents) 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 may have authorised the building of a new town. It may 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 base-line service commitments that trigger substantial penalties if service is interrupted. The government requires the power to entity provide universal access to the electricity network for all residents of the town.

This arrangement would fall within the scope of IFRIC 12, as 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 the 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 seldom are the conclusions 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 may have elements of both models for the different phases. It may be appropriate to separately account for each element of the consideration.

1.5.2 Business combinations

Acquisitions of assets and businesses are common in the utility industry. These may be business combinations or acquisitions of groups of assets. IFRS 3R, *Business Combinations*, provides guidance on both types of transactions, and the accounting can differ significantly. These guidelines are mandatory for all calendar year companies from 2010 onward.

The changes introduced by IFRS 3R in accounting 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 3R 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 3R than were considered such under the previous standard.

IFRS 3R 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.

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

- 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 country falls squarely into the scope of IFRS 3R as a business combination. The classification of the acquisition of a single pipeline, or a portion of a transmission network, may not be so clear cut.

IFRS 3R 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 for example:

- A utility might have a brand name and a logo. The fair value of the intangible assets may 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 may have value, but likely 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 (not

freely transferable). The licence and fixed assets are usually valued on the basis of expected cash flows and 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 ventures

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

The IASB published IFRS 11, *Joint Arrangements*, in May 2011. The standard introduces a number of significant changes in the accounting for joint arrangements, including:

- "Joint arrangement" replaces "joint venture" as the new umbrella term to describe all arrangements where two or more parties have joint control.
- The two types of joint arrangement are: "joint operations" and "joint ventures".
- Contractual rights and obligations drive the categorisation of a joint arrangement as a joint operation or a joint venture.
- The policy choice of proportionate consolidation for joint ventures is eliminated.
- An "investor in a joint venture" is defined as a party who does not participate in joint control, with guidance on the appropriate accounting.

Unanimous consent must be present over the financial and operating decisions in order for joint control to exist.

IFRS 11 becomes effective in 2013, although earlier application is allowed. Most companies are expected to adopt the standard only when it becomes mandatory. The requirements of IFRS 11 are discussed in Chapter 3 of this document, *Future developments—Standards issued and not yet effective*. This chapter is based on

the requirements of IAS 31, although it uses the new umbrella term “joint arrangements”.

Joint control

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

Not all parties to the joint venture need to share joint control. Some participants may share joint control and other investors participate in the activity but not in the joint control. Those investors account for their interest in its share of assets and liabilities, an investment in an associate (if they have significant influence) or as an available-for-sale financial asset in accordance with IAS 39.

Similarly, joint control may not be present even if an arrangement is described as a joint venture. Decisions over financial and operating decisions that are made by simple majority rather than by unanimous consent could mean that joint control is not present, even in situations where there are only two shareholders but each has appointed a number of directors to the Board or relevant decision-making body.

Joint control exists only if decisions require the unanimous consent of the parties sharing control. If decisions are made by simple majority, the following factors may indicate that joint control does not exist:

- The directors are not agents or employees of the shareholders
- The shareholders have not retained veto rights
- There are no side agreements requiring that directors vote together
- A quorum of Board members can be achieved without all members being in attendance

If it is possible that a number of combinations of the directors would be able to reach a decision, it may be that joint control does not exist. This is a complex area which requires careful analysis of the facts and

circumstances. If joint control does not exist, the arrangement would not be a joint venture.

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

One of the venturers acting as operator of the joint venture (for example a power plant) does not prevent joint control. The operator’s powers are usually limited to day-to-day operational decisions; key strategic financial and operating decisions remain with the joint venture partners collectively.

Classification of joint arrangements

Joint arrangements are analysed into three classes under the current standard: jointly controlled operations, jointly controlled assets and jointly controlled entities.

Jointly controlled assets exist when the venturers jointly own and control the assets used in the joint venture. Jointly controlled assets are likely to meet the definition of joint operations when companies adopt IFRS 11.

Jointly controlled operations are arrangements where each venture uses its own property, plant and equipment; raises its own financing; and incurs its own expenses and liabilities.

Jointly controlled entities exist when the venturers jointly control an entity which in turn owns the assets and liabilities of the joint venture. A jointly controlled entity is usually, but not necessarily, a legal entity. The key to identifying an entity is to determine whether the joint venture can perform the functions associated with an entity, such as entering into contracts in its own name, incurring and settling its own liabilities and holding a bank account in its own right.

Accounting for joint arrangements

A venturer in a jointly controlled asset arrangement recognises:

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

Jointly controlled assets tend to reflect the sharing of costs and risk rather than the sharing of profits. An example is an undivided interest in a wind farm where each venturer receives its share of the power produced, is jointly liable for costs and is part of the joint control decision making.

The parties to the joint operation share the revenue and expenses of the jointly produced end product. Each retains title and control of its own assets. The venturer should recognise 100% of the assets it controls and the liabilities it incurs as well as its own expenses, its share of income from the sale of goods or services of the joint operation and its share of expenses jointly incurred.

Jointly controlled entities can be accounted for either by proportionate consolidation or using equity accounting using the policy choice available under IAS 31. The policy must be applied consistently to all jointly controlled entities. Proportionate consolidation will be eliminated as a policy choice when IFRS 11 is adopted.

The key principles of the equity method of accounting are:

- Investment in the jointly controlled entity is initially recognised at cost.
- Changes in the carrying amount of the investment are recognised based on the venturer's share of the profit or loss of the jointly controlled entity after the date of acquisition.
- The venturer reflects only its share of the profit or loss of the jointly controlled entity.
- Distributions received from a jointly controlled entity reduce the carrying amount of the investment.

Contributions to jointly controlled entities

It is common for venturers to contribute assets, such as cash, non-monetary assets or a business, to a joint venture on formation. Contributions of assets are a partial disposal by the contributing party. The venturer in return receives a share of the assets contributed by the other venturers. Accordingly, the contributor should recognise a gain or loss on the partial disposal. The gain is measured as the proportionate share of the fair value of the assets contributed by the other venturers less the portion of the book value of contributor's disposed asset now attributed to the other venturers.

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

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

Entities A and B have brought together their power plants in a market in order to strengthen their market position and reduce costs. They established a new entity, J, and contributed the plants to Entity J. Entity A receives 60% of the shares in Entity J, and Entity B receives 40%.

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

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

Can Entity A's management do this?

Yes, there is a policy choice available to Entity A in certain circumstances because of the conflict in the accounting standards described below. Entity A can choose partial recognition of the gain or loss being the difference between 40% of the fair value of its plants contributed and 40% of their carrying amount plus its 60% share of the fair value of the plants contributed by Entity B. This is the approach set out in SIC 13. Entity A may also recognise 100% of the gain arising on its disposal of its power plants business following IAS 27 – see narrative below.

Entity A must therefore eliminate its share (retained) of the fair value of the power plants it previously held and that are accounted for at fair value at the level of Entity J when applying the equity method of accounting.

The example above is based on guidance provided within SIC-13, *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. An inconsistency exists between SIC-13 and IAS 27, *Consolidated and Separate Financial Statement*, when the contribution to the jointly controlled entity is considered to represent a business.

IAS 27 has different guidance on the loss of control of a business. Any investment a parent has in the former subsidiary after control is lost is measured at fair value at the date that control is lost, and any resulting gain or loss is recognised in profit or loss in full.

The IASB have not dealt with this conflict in IFRS 11, but will do so as part of a wider project on equity accounting. While this conflict remains, entities can make a policy choice in these types of transactions.

2 *Financial instruments*

2 *Financial instruments*

2.1 *Overview*

The accounting for financial instruments can have a major impact on a power and utility entity's financial statements. 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 instruments issues arise through both the scope of IAS 39 and the rules around accounting for embedded derivatives. Many entities that are engaged in generation, transmission and distribution of electricity may be party to commercial contracts that are within the scope of IAS 39. Other entities may 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 may 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*

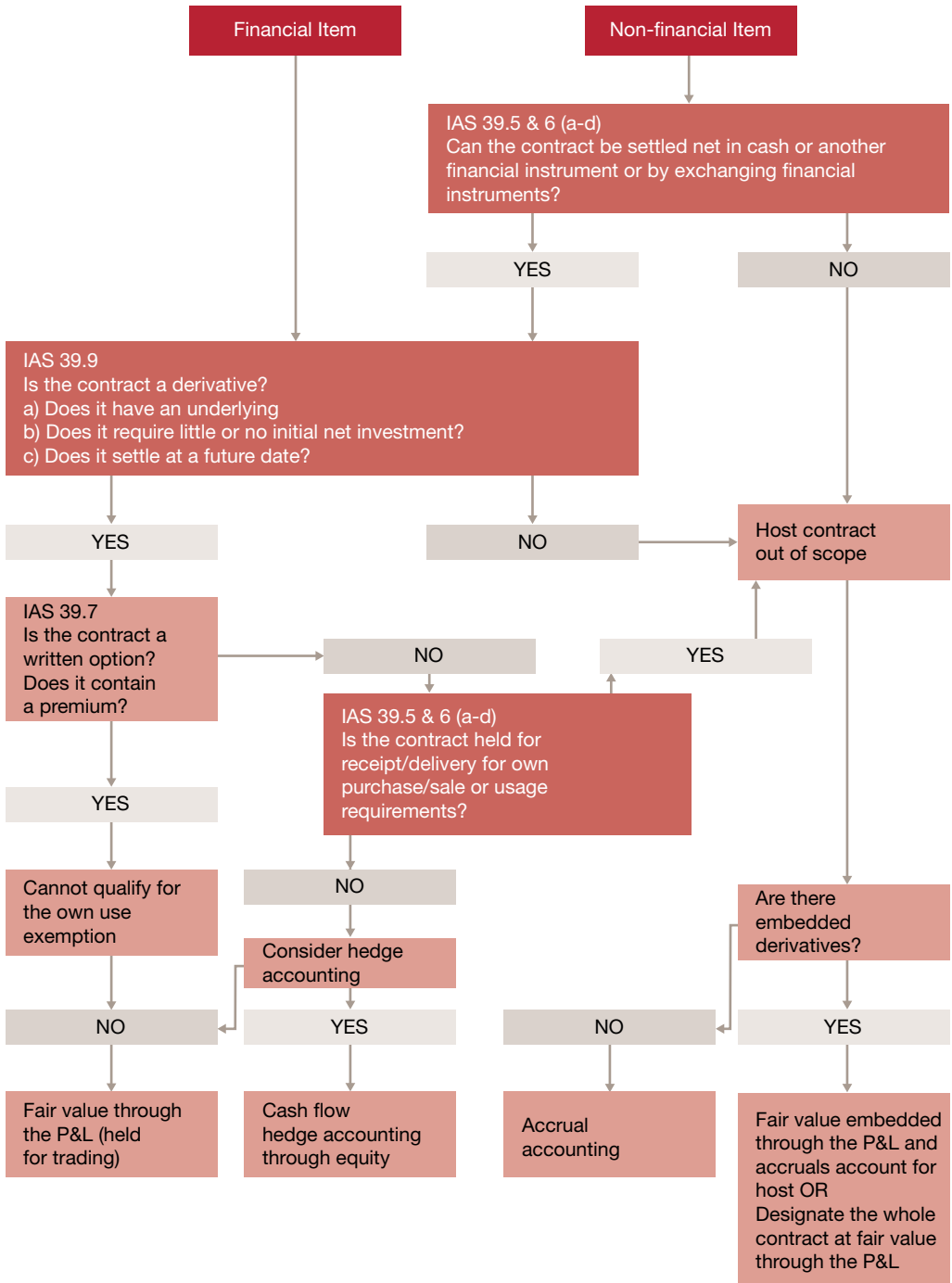
Contracts to buy or sell a non-financial item, such as a commodity, that can be settled net in cash or another financial instrument, or by exchanging financial instruments, are within the scope of IAS 39 and are subject to fair value accounting unless the own use exemption applies. Contracts within the 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
 - 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 (i.e., all similar contracts must then be recognised as derivatives at fair value). If the entity has a practice of settling similar contracts net (b) 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 (c) 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 it net in cash or another financial instrument (a) or the commodity that is the subject of the contracts is readily convertible to cash (d) 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 when 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 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 takes 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 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 upon each delivery the difference between the forecasted price of gas and the prevailing market price is settled in cash.

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

Is this contract an own use contract?

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 IAS 39.6(a). The expected frequency/intention to pay a penalty rather than deliver does not matter as the conclusion is driven by the presence of the contractual provision. Further, if natural gas is readily convertible into cash in the location where the delivery takes place, the contract 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 then the contract is to be regarded as a written option. A written option is not entered into for own use.

Therefore, although the contract may be considered net settled (depending on how the penalty mechanism works and whether natural gas is readily convertible into cash in the respective location), the own use exemption does still apply provided the contract is entered into and is continued 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 purchase of fuel and sale of power and gas. Some of these contracts may 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 may 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 may not be available for the entire period of the contract. For example, prices may be available for the next three years and then some prices for specific dates further out. This is described as having illiquid periods in the contract. These contracts are valued using valuation techniques.

Contracts for commodities that are not readily convertible to cash (i.e., for which no active market exists, such as gas in certain markets or gas capacity) do not meet the definition of a derivative and therefore are accounted for as executory contracts.

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
- (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,

are crucial to ensure 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 include recognised gains and losses in profit and loss, total gains and losses in comprehensive income as well as purchases, sales, issues and settlements (IFRS 7.27B). 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
- (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 (i.e., 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 may 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 the generator requires may be less than the minimum agreed amount in any one measurement period. The generator may be

required to pay the supplier the equivalent monetary value of the shortfall, or the shortfall amount may also be carried forward and used in satisfaction of supply in subsequent periods.

A long-term take-or-pay contract may not fall within the scope of IAS 39 because of inherent variability in amount and/or the ability to “net settle” may 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 through 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 therefore 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 the 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 may 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 the guaranteed volume for its own use.

A derivative or an embedded derivative may arise if it becomes likely that the entity will not take the commodity, and 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.

The contracts 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 the quantities specified in the contract and sell the excess or 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 may 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, the supplier would be prevented from classifying the contract as own use by paragraph 7 of IAS 39. 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 of 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 when 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 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. In cases 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 paragraph 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 may 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 may need a sophisticated valuation system and relatively large number of data inputs (which may 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 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:

- (i) 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 out of 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.
- (ii) The contract is evaluated as a single contract. The contract is considered as a whole to be a written option. Accordingly, IAS 39.7 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 IAS 8 paragraph 13.

2.6 Embedded derivatives

Long-term commodity purchase and sale contracts frequently contain a pricing clause (i.e., indexation) based on a commodity or index other than the commodity deliverable under the contract. Such contracts contain embedded derivatives that may have to be separated and accounted for under IAS 39 as a derivative. Examples are 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
- (c) The hybrid (combined) instrument is not measured at fair value with changes in fair value recognised in the profit or loss (i.e., a derivative that is embedded in a financial asset or financial liability at fair value through profit or loss is not separated)

Embedded derivatives that are not closely related must be separated from the host contract and accounted for at fair value, with changes in fair value recognised in the income statement. In rare cases, it may 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 may be designated as a hedging instrument, in which case the hedge accounting rules are applied. A contract that contains one or more embedded derivatives can be designated as a contract at fair value through profit or loss at inception, unless:

- (a) The embedded derivative(s) does not significantly modify the cash flows of the contract
- (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 indexation of a published market price and denomination in a foreign currency that is not the functional currency of either party and not a currency in which such contracts are routinely denominated in transactions around the world.

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

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

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 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 has occurred when the expected future cash flows associated with the embedded derivative, host contract, or hybrid contract have significantly changed relative to the previously expected cash flows under the contract.

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

The same principles apply to an entity that purchases a contract containing an embedded derivative. The date of purchase is treated as the date when the entity first becomes 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 IAS 39.6(d). 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 own use, 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 (a quantitative analysis failed). The contract is recorded at its fair value at acquisition date but 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 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
- b) To benefit from the potential arbitrage between various gas networks across the world which are not connected otherwise

The application of the own use exemption could become quite complex, particularly for the definition

of net settlement. The principles of paragraphs 5–7 of IAS 39 should still be applied; however, there may be some practical challenges to this. The explanation in section 2.8 of how energy trading units operate provides some of the practical considerations. In the absence of a global LNG reference price, most contracts are currently priced based on other energy indices (e.g., Henry Hub Natural gas index, Brent Oil index). 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 able to qualify for the own use exemption may 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).

Two hurdles to implementing hedge accounting are the need for documentation and the testing of effectiveness. IAS 39 requires that at inception of the hedge, individual hedging relationships are formally documented, 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 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 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 (i.e., changes in the fair value or cash flows of the hedged item should be between 80% and 125% of the changes in fair value or cash flows of the hedging instrument).

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, which for listed companies 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 may 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 therefore are cash flow hedges. Under IFRS, only a highly probable forecast transaction can be designated as a hedged item in a cash flow hedge relationship. The hedged item must be assessed regularly until the transaction occurs. If the forecasts change and the forecasted transaction is no longer expected to occur, the hedge relationship must be ended immediately and all retained hedging results in the hedging reserve must be recycled to the income statement. Cash flow hedging is not available if an entity is not able to forecast the hedged transactions reliably.

Entities that buy or sell commodities (e.g., utilities) may designate hedge relationships between hedging instruments, including commodity contracts that are not treated as own use contracts, and hedged items. In addition to hedges of foreign currency and interest rate risk, energy companies primarily hedge the exposure to variability in cash flows arising from commodity price risk in forecast purchases and sales.

Hedging of non-financial items

It is difficult to isolate and measure the appropriate portion of the cash flows or fair value changes attributable to specific risks other than foreign currency risks. Therefore, a hedged item which is a non-financial asset or non-financial liability may be designated as a hedged item only for:

- a. Foreign currency risks
- b. In its entirety for all risks
- 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 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 may or may not be based on the amount of loss suffered by the entity. Weather derivatives are either insurance contracts and fall into IFRS 4 or financial instruments and 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 (i.e., 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 may meet the definition of a written option when the acquiring entity reassesses them at the acquisition date. Consequently, the acquiring entity won't be able to designate such derivatives as hedging instruments.

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:

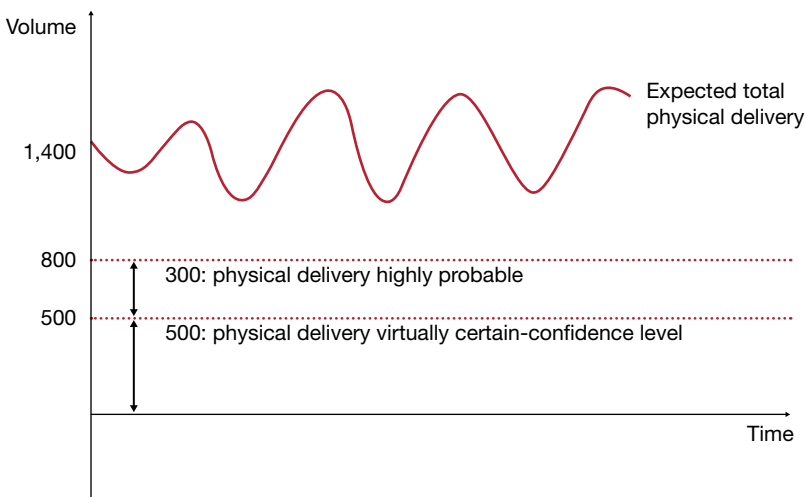
- (a) Transactions that are non-speculative in nature
The purchase of fuel to meet the physical requirements of the generation stations and the sale of any excess power generated compared to retail demand, or the purchase of power to meet a shortfall between that generated and that required by retail. 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 (i.e., 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 may 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 may have active energy trading programmes that go far beyond mitigation of risk. This practice has many similarities to the trading activities of other commodities, such as gold, sugar or wheat.

A contract must meet the own use requirements to be included in the own use or physical book. Contracts must meet the physical requirements of the business at inception and continue to do so for the duration of the contract.

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 management of the entity (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 (e.g., trading margin) above gross operating profit. Such a disclosure would provide a more accurate reflection of the nature of trading operations than presentation on a gross basis.

3 Future developments – standards issued and not yet effective

3 Future developments – standards issued and not yet effective

3.1 Overview

2011 is a period of significant activity for the IASB. The timetable had originally called for a number of financial-crisis-related projects (including consolidation, joint arrangements and hedge accounting) to be finalised. Some key memorandum of understanding projects, such as leasing and revenue, were also scheduled to be published in summer 2011.

Consolidation, joint arrangements and fair value measurement have all now been issued as final standards; however, the decision was taken to re-expose leasing and revenue. At the time of writing, these projects, together with hedge accounting, remain ongoing, and the final versions of these standards could have significant differences from proposals to date.

This section focuses on those standards which have been issued and are not yet effective. Ongoing projects which have not been finalised will be examined in separate publications as the development of those standards progresses.

3.2 Consolidation and joint arrangements

The IASB issued three new standards in May 2011: IFRS 10, *Consolidation*, IFRS 11, *Joint Arrangements*, and IFRS 12, *Disclosure*. The standards replace IAS 27, *Consolidated and Separate Financial Statements* (which is amended to become IAS 27, *Separate Financial Statements*), and IAS 31, *Interests in Joint Ventures*. There have also been consequential amendments to IAS 28, *Investments in Associates*, which is now IAS 28, *Investments in Associates and Joint Ventures*. The standards are effective for 2013, and early adoption is permitted if all five standards are adopted at the same time.

3.2.1 Consolidation

IFRS 10 confirms consolidation is performed where control exists but does not affect the mechanics of consolidation. However, the standard redefines control to exist where an investor has power, exposure to variable returns and the ability to use that power to affect its returns from the investee. As a result, changes to the composition of the consolidated group may occur.

As multiple-party arrangements are becoming more common in the utilities industry with introduction

of renewable technologies, the determination of the type of control which exists is important. The rights of investors to make decisions over relevant activities (now defined as those which significantly affect the investee's returns) are critical in this determination.

Factors to be assessed 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
- Relationships between investors and how they affect control

IFRS 10 requires that only substantive rights shall be considered in the assessment of power – protective rights, designed only to protect an investor's interest without giving power over the entity and which may only be exercised under certain conditions, are not considered.

Potential voting rights are defined as "rights to obtain voting rights of an investee, such as those within an option or convertible instrument." If these rights can be exercised prior to major decision-making events, such as annual general meetings, they should be considered when determining control.

The "principal vs. agent" determination is also important. Sometimes one party may be designated to operate the project on behalf of the investors. A principal may delegate some of its decision authority to the agent, but the agent would not be viewed as having control when it exercises such powers on behalf of the principal.

Economic dependence of an arrangement, such as a generator which relies solely on one fuel source, 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.

3.2.2 Joint arrangements

Under the new IFRS 11, "joint arrangement" is the term now used to describe all types of arrangements where two or more parties have joint control. The definition of joint control is unchanged from IAS 31, and exists only when decisions about key decisions require unanimous consent. There is some clarification that such key decisions must be about relevant activities (previously IAS 31 referred to "strategic financial and operating decisions") which IFRS 10 defines as activities which significantly affect the investee's returns.

The standard also introduces other new terminology:

Under IAS 31	Under new IFRS 11	IFRS 11 definition
Jointly controlled asset	Joint operation	Parties have rights to the assets and obligations for the liabilities relating to the arrangement
Jointly controlled operation	Joint operation	Parties have rights to the assets and obligations for the liabilities
Jointly controlled entity	Joint venture	Parties have rights to the net assets of the arrangement

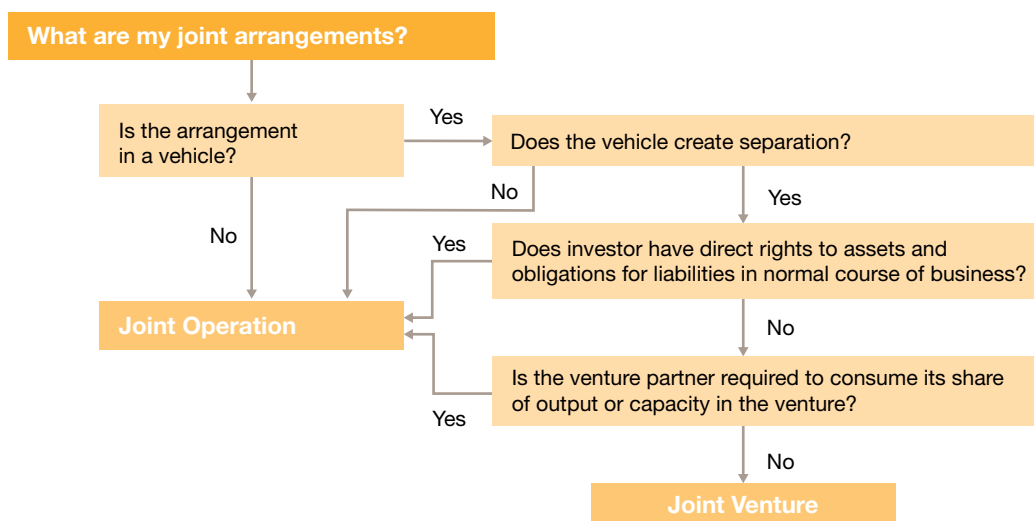
Classification

The classification of the joint arrangement is now based on the rights and obligations of the parties to the arrangements. This represents a significant change from IAS 31, where the classification was instead based on the legal form of the arrangement.

Determination of the type of joint arrangement can be a complex decision under IFRS 11. Legal form remains relevant for determining the type of joint arrangement but is less important than under the previous standard. A joint arrangement that is not structured through a separate vehicle is a joint operation. That does not mean that all joint arrangements in separate vehicles

are joint ventures. A joint arrangement in a separate vehicle can still be a joint operation; it depends on the rights and obligations of the venturers and is further influenced by the economic purpose of the joint arrangement.

As the standard has been issued recently, entities, users and practitioners are in the early stages of forming their views, and practices may evolve as the standard is further assessed and applied. The flowchart below, based on our current interpretation of the standard, attempts to illustrate the decision-making process and what needs to be considered to properly classify joint arrangements as operations or ventures.



Joint arrangements operate in different types of vehicles in the utilities industry, including partnerships, unincorporated entities, limited companies and unlimited liability companies. Venturers will have to assess all their joint arrangements and identify those that are operated through vehicles.

Sometimes the legal structure of the vehicle or the contractual terms between the venturers does not allow legal separation of the venture from the venture partners (i.e., the venturers remain exposed to direct interest in the assets and liabilities of the venture). For example, sometimes general partnerships do not create separation from the partners because the contractual terms contained in the partnership provide direct rights to assets and expose the partners to direct obligations for liabilities of the partnership in the normal course of business. Similarly, unlimited liability companies provide direct rights and obligations to the venture partners. It can be challenging to assess the contractual terms of all arrangements to identify whether it creates separation. Vehicles that do not create separation are joint operations.

The parties' rights and obligations arising from the arrangement have to be assessed as they exist in the "normal course of business" (Para B14 of IFRS 11). Hence, legal rights and obligations arising in circumstances which are other than in the "normal course of business", such as liquidation and bankruptcy, should not be considered. For example, a separate vehicle may give the venture partners rights to assets and obligations to liabilities as per the terms of their agreement. However, in case of liquidation of the vehicle, secured creditors have the first right to the assets and the venture partners have rights only in the net assets remaining after settling all third-party obligations. Such a vehicle would be considered a joint operation since in the "normal course of business" the venture partners have direct interest in assets and liabilities. Separate vehicles that give venture partners direct rights to assets and obligation for liabilities of the vehicle are joint operations.

Separate vehicles structured in a manner that all of their outputs are purchased or consumed by the venture partners are more likely to be joint operations. However, contractual terms and legal structure of the vehicle need to be carefully assessed. There has to be a contractual agreement or commitment between the venture parties that requires them to purchase/consume their share of the output or capacity in the venture. If the venture can sell the output to third parties at prices independently determined by it, this criterion will not be met.

Accounting

The classification of the joint arrangement is important because IFRS 11 requires use of equity accounting for investments in joint arrangements. Therefore, investors who previously had a choice between equity accounting and proportionate consolidation will no longer have that choice. Arrangements previously accounted for under proportionate consolidation will have to change to equity accounting if the arrangement is concluded to be a joint venture.

Investors in joint operations are required to account for their share of assets and liabilities. Again, this would mean a change in accounting where they had chosen equity accounting for a jointly controlled entity, but that arrangement was concluded to be a joint operation under IFRS 11. It should also be noted that the share of assets and liabilities is not the same as proportionate consolidation. "Share of assets and liabilities" means that the investor should consider their interest or obligation in each underlying asset and liability under the terms of the arrangement – it will not necessarily be the case that they have a single, standard percentage interest in all assets and liabilities. This is also an important consideration when transitioning to the new standard.

Transition

Entities must re-evaluate the terms of their existing contractual arrangement to ensure that their involvement in joint arrangements are correctly accounted for under the new standard. Joint arrangements that were previously accounted for as joint operations may need to be treated as joint ventures, or vice versa, on transition to the new standard. This will change the way they report their respective rights and obligations in their financial statements.

When transitioning from the proportionate consolidation method to the equity method, entities should recognise their initial investment in the joint venture as the aggregate of the carrying amounts that were previously proportionately consolidated.

To transition from the equity method to proportionate consolidation, entities will derecognise their investment in the jointly controlled entity and recognise their rights and obligations to the assets and liabilities of the joint operation. Their interest in those assets and liabilities may be different from their interest in the jointly controlled entity.

Moving from the equity method to a share of assets and liabilities is not always a simple process. For example, parties may have contributed specific assets to a joint arrangement. When evaluating interest based on share of assets and liabilities, parties account for their interest in the arrangement based on the share of assets contributed by them. The interest calculated based on assets contributed does not necessarily result in the same interest that the party may have in the equity of that entity. Where there is a difference between the value recorded under equity accounting and the net value of the gross assets and liabilities, this is written off against opening retained earnings.

Similarly, moving from proportionate consolidation to equity method could pose challenges. For example, the liabilities of a joint arrangement assessed to be a joint venture may exceed the assets. Netting these may result in the venturer's investment becoming negative, in which case the venturers have to assess whether they need to record a liability in respect of that negative balance. This depends on whether the venturer has an obligation to fund the liabilities of the joint arrangement. If there is no obligation, then the balance is written off against opening retained earnings. If there is an obligation, further consideration should be given as to whether the assessment of the arrangement as a joint venture was correct.

Impact in the power and utilities industry

Entities in the sector that are likely to be most significantly impacted include those that:

- Enter into new joint arrangements
- Currently apply proportionate consolidation for jointly controlled entities
- Currently apply equity method for jointly controlled entities which are assessed to be joint operations under IFRS 11
- Participate in a significant number of existing complex joint arrangements
- Have old joint arrangements with limited documentation detailing the terms of the arrangement

3.3 Fair value measurement

The IASB released IFRS 13, *Fair Value Measurement*, in May 2011. IFRS 13 consolidates fair value measurement guidance across various IFRSs into a single standard, and applies when another IFRS requires to permit fair value measurements, including fair value less costs to sell. As the requirements are

largely consistent with current valuation practices, it is not expected that adoption of this standard will result in substantial change.

The main changes introduced are:

- An introduction of fair value hierarchy levels for non-financial assets, similar to current IFRS 7 requirements
- A requirement for the fair value of financial liabilities (including derivatives) to be determined based on the assumption that the liability will be transferred to another party rather than settled or extinguished
- The removal of the requirement for bid prices to be used for actively quoted financial assets and ask prices to be used for actively quoted financial liabilities. Instead, the most representative price within the bid-ask spread should be used.
- Additional disclosure requirements

The new standard is available for immediate adoption, and is mandatory from 2013.

3.4 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 January 1, 2015 (as tentatively agreed by recent Board decisions – this is expected to be confirmed by the end of 2011), and early adoption is permitted. IFRS 9 should be applied retrospectively; however, if adopted before January 2012, the standard does not require comparative periods to be restated.

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 to current practice.

How does it impact the power and utility 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 won't be impacted, as 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.
- 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 may need to be measured at fair value.

IFRS 9 prohibits reclassifications from amortised cost to fair value (or vice versa) except in rare circumstances when 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 may 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>	<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).</p>	<p>Measured at fair value with gains/losses recognised in the income statement or through other comprehensive income if applicable.</p>	<p>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.</p>
<p>Available-for-sale debt instruments (e.g., corporate bonds)</p>	<p>Recognised at fair value with gains/losses deferred in other comprehensive income.</p>	<p>Measured at amortised cost where certain criteria are met. Where criteria are not met, measured at fair value through profit and loss.</p>	<p>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.</p>

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 when 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 may elect the fair value option where they have accounting mismatches with assets that are required to be held at fair value through profit or loss.

Financial liabilities that are required to be measured at fair value through profit or loss (as distinct from those that the entity has chosen to measure at fair value through profit or loss) continue to have all fair value movements recognised in profit or loss with no transfer to OCI. This includes all derivatives (such as foreign currency forwards or interest rate swaps), or an entity’s own liabilities that it classifies as being held for trading.

Amounts in OCI relating to own credit are not recycled to the income statement, even when the liability is derecognised and the amounts are realised. However, the standard does allow transfers within equity.

What else should entities in the power and utility 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 when 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 doesn’t 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 chosen, 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 may want 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

entities would like to reclassify their financial assets. Upon 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

RWE AG
(31 December 2010, pages 203, 204)

“Provisions for nuclear waste management are almost exclusively recognised as non-current provisions, and their settlement amount is discounted to the balance-sheet date. From the current perspective, the majority of utilisation is anticipated to occur in the years 2020 to 2050. As in the previous year, the discount factor was 5.0 %. Volume-based increases in the provisions

are measured at their present value. In the reporting period, they amounted to €92 million (previous year: €122 million). Further additions of €88 million in provisions (previous year: release of €388 million) stem from the fact that current estimates project a net increase in anticipated waste disposal costs (previous year: decrease). Additions to provisions for nuclear waste management primarily consist of an interest accretion of €472 million (previous year: €446 million). €833 million in prepayments, primarily to foreign reprocessing companies and to the German Federal Office for Radiation Protection (BfS) for the construction of final storage facilities, were deducted from these provisions (previous year: €796 million).

In terms of their contractual definition, provisions for nuclear waste management break down as follows:

Provisions for nuclear waste management € million	31 Dec 2010	31 Dec 2009
Provisions for nuclear obligations, not yet contractually defined	7,977	7,557
Provisions for nuclear obligations, contractually defined	2,033	1,934
	10,010	9,491

In respect of the disposal of spent nuclear fuel assemblies, the provisions for obligations which are not yet contractually defined cover the estimated long-term costs of direct final storage of fuel assemblies, which is currently the only possible disposal method in Germany, as well as the costs for the disposal of radioactive waste from reprocessing, which essentially consist of costs for transport from centralised storage facilities and the plants’ intermediate storage facilities to reprocessing plants and final storage as well as conditioning for final storage and containers. These estimates are mainly based on studies by internal and external experts, in particular by GNS Gesellschaft für Nuklear-Service mbH in Essen, Germany. With regard to the decommissioning of nuclear power plants, the costs for the post-operational phase and dismantling are taken into consideration, on the basis of data from external expert opinions prepared by NIS Ingenieurgesellschaft mbH, Alzenau, Germany, which are generally accepted throughout the industry and are updated continuously. Finally, this item also covers all of the costs of final storage for all radioactive waste, based on data provided by BfS.

Provisions for contractually defined nuclear obligations are related to all nuclear obligations for the disposal of fuel assemblies and radioactive waste as well as for the decommissioning of nuclear power plants, insofar as the value of said obligations is specified in contracts under civil law. They include the anticipated residual costs of reprocessing, return (transport, containers) and intermediate storage of the resulting radioactive waste, as well as the additional costs of the utilisation of uranium and plutonium from reprocessing activities. These costs are based on existing contracts with foreign reprocessing companies and with GNS. Moreover, these provisions also take into account the costs for transport and intermediate storage of spent fuel assemblies within the framework of final direct storage. The power plants’ intermediate storage facilities are licensed for an operational period of 40 years. These facilities commenced operations between 2002 and 2006. Furthermore, the amounts are also stated for the conditioning and intermediate storage of radioactive operational waste, which is primarily performed by GNS.

With due consideration of the German Atomic Energy Act (AtG), in particular to Sec. 9a of AtG, the provision for nuclear waste management breaks down as follows:

Provisions for nuclear waste management € million	31 Dec 2010	31 Dec 2009
Decommissioning of nuclear facilities	4,490	4,626
Disposal of nuclear fuel assemblies	4,831	4,303
Disposal of radioactive operational waste	689	562
	10,010	9,491

Provisions for mining damage also consist almost entirely of non-current provisions. They are reported at the settlement amount discounted to the balance-sheet date. As in the previous year, we use a discount factor of 5.0 %. In the reporting period, additions to provisions for mining damage amounted to €117 million (previous year: €165 million). Of this, an increase of €67 million (previous year: €84 million) was capitalised under property, plant and equipment. The interest accretion of the additions to provisions for mining damage amounted to €151 million (previous year: €121 million).”

Centrica plc (31 December 2010, pages 76, 82)

“Provision is made for the net present value of the estimated cost of decommissioning gas production facilities at the end of the producing lives of fields, and storage facilities and power stations at the end of the useful life of the facilities, based on price levels and technology at the balance sheet date.

When this provision gives access to future economic benefits, a decommissioning asset is recognised and included within property, plant and equipment. Changes in these estimates and changes to the discount

rates are dealt with prospectively and reflected as an adjustment to the provision and corresponding decommissioning asset included within property, plant and equipment. For gas production facilities and offshore storage facilities the decommissioning asset is amortised using the unit of production method, based on proven and probable reserves. For power stations the decommissioning asset is amortised on a straight-line basis over the useful life of the facility. The unwinding of the discount on the provision is included in the Income Statement within interest expense.

[...]

The estimated cost of decommissioning at the end of the producing lives of fields is reviewed periodically and is based on proven and probable reserves, price levels and technology at the balance sheet date. Provision is made for the estimated cost of decommissioning at the balance sheet date. The payment dates of total expected future decommissioning costs are uncertain and dependent on the lives of the facilities, but are currently anticipated to be between 2011 and 2055, with the substantial majority of the costs expected to be paid between 2020 and 2030.”

Impairment

National Grid plc (31 March 2011,
page 136)

"9. Goodwill	Total £m
Cost at 31 March 2009	5,391
Exchange adjustments	(289)
Cost at 31 March 2010	5,102
Exchange adjustments	(280)
Impairment of goodwill on businesses reclassified as held for sale (notes 3 and 18) (1)	(34)
Reclassified as held for sale	(12)
Cost at 31 March 2011	4,776
Net book value at 31 March 2011	4,776
Net book value at 31 March 2010	5,102
(1) Relates to our gas operations (£30m) and our electricity distribution operations (£4m)	

The amounts disclosed above as at 31 March 2011 include balances relating to our US gas operations of £2,876m (2010: £3,077m), our New England electricity distribution operations of £819m (2010: £881m), our operations run by our subsidiary Niagara Mohawk Power Corporation of £849m (2010: £898m) and our New England transmission operations of £232m (2010: £246m).

Goodwill is reviewed annually for impairment and the recoverability of goodwill at 31 March 2011 has been assessed by comparing the carrying amount of our operations described above (our cash generating units) with the expected recoverable amount on a value-in-use basis. In each assessment the value-in-use has been calculated based on four year plan projections that incorporate our best estimates of future cash flows, customer rates, costs, future prices and growth. Such projections reflect our current regulatory rate plans taking into account regulatory arrangements to allow for future rate plan filings and recovery of investment. Our plans have proved to be reliable guides in the past and the Directors believe the estimates are appropriate.

The future growth rate used to extrapolate projections beyond four years has been reduced to 2.4%. The growth rate has been determined having regard to data on projected growth in US real gross domestic product (GDP). Based on our business's place in the underlying US economy, it is appropriate for the terminal growth rate to be based upon the overall growth in real GDP and, given the nature of our operations, to extend over a long period of time. Cash flow projections have been discounted to reflect the time value of money, using an effective pre-tax discount rate of 10% (2010: 10%). The discount rate represents the estimated weighted-average cost of capital of these operations.

While it is possible that a key assumption in the calculation could change, the Directors believe that no reasonably foreseeable change would result in an impairment of goodwill, in view of the long-term nature of the key assumptions and the margin by which the estimated fair value exceeds the carrying amount."

**RWE AG (31 December 2010,
pages 187, 188)**

“In the reporting period, the RWE Group’s total expenditures on research and development amounted to €149 million (previous year: €110 million).

Development costs of €112 million were capitalised (previous year: €104 million).

As of the balance-sheet date, the carrying amount of intangible assets related to exploration activities amounted to €374 million (previous year: €415 million).

Goodwill breaks down as follows:

Goodwill € million	31 Dec 2010	31 Dec 2009
Germany	4,186	3,937
Power Generation	(404)	(404)
Sales and Distribution Networks	(3,782)	(3,533)
Netherlands/Belgium	2,665	3,504
United Kingdom	2,968	2,877
Central Eastern and South Eastern Europe	2,048	1,956
Renewables	736	441
Upstream Gas & Oil	25	26
Trading/Gas Midstream	944	434
Others		77
	13,572	13,252

In the reporting period, goodwill increased by €130 million. An increase in current redemption liabilities from put options resulted in an adjustment without an effect on income of €213 million to the goodwill of the segment Sales and Distribution Networks. Declines in goodwill primarily resulted from the reporting of Thyssengas as “Assets and liabilities held for sale” (€77 million). In respect of additions to goodwill in the previous year (€3,871 million), €3,435 million resulted from the acquisition of Essent. With the assignment of Essent’s trading activities and wind power generation to the segments Trading/Gas Midstream and Renewables, goodwill of €510 million and €285 million, respectively, was allocated to these segments. Goodwill of €43 million was allocated to the segment Sales and Distribution Networks, based on the assignment of Essent’s gas storage activities.

In the third quarter of each fiscal year, the regular impairment test is performed to determine if there is any need to write down goodwill. In order to carry out this impairment test, goodwill is allocated to the cash-generating units at the segment level. The impairment test involves determining the recoverable

amount of the cash-generating units, which is defined as the higher of fair value less costs to sell or value in use. The fair value reflects the best estimate of the price that an independent third party would pay to purchase the cash-generating unit as of the balance-sheet date. Value in use is the present value of the future cash flows which are expected to be generated with a cash-generating unit.

Fair value is assessed from an external perspective and value in use from a company-internal perspective. We determine both variables using a business valuation model, taking into account planned future cash flows. These cash flows, in turn, are based on the business plan, as approved by the Executive Board and valid at the time of the impairment test, and pertain to a detailed planning period of up to five years. In certain justifiable cases, a longer detailed planning period is taken as a basis, insofar as this is necessary due to economic or regulatory conditions. The cash flow plans are based on experience as well as on expected market trends in the future. If available, market transactions in the same sector or third-party valuations are taken as a basis for determining fair value.

Mid-term business plans are based on country-specific assumptions regarding the development of key economic indicators such as gross domestic product, consumer prices, interest rate levels and nominal wages. These estimates are, amongst others, derived from macroeconomic and financial studies.

The key planning assumptions for the business segments active in Europe's electricity and gas markets are estimates relating to the development of wholesale prices for electricity, crude oil, natural gas, coal and CO2 emission allowances, retail prices for electricity and gas, and the development of market shares and regulatory framework conditions.

The discount rates used for business valuations are determined on the basis of market data. With regard to cash-generating units, during the period under review they ranged from 6.25 % to 9.00 % after tax (previous year: 6.5 % to 9.0 %) and from 8.0 % to 16.5 % before tax (previous year: 8.8 % to 15.6 %).

For the extrapolation of future cash flows going beyond the detailed planning horizon, we assumed constant growth rates of 0.0 % to 1.0 % (previous year: 0.0 % to 1.0 %). These figures are derived from experience and future expectations for the individual divisions and do not exceed the long-term average growth rates in the markets in which the Group companies are active. In calculating cash flow growth rates, the capital expenditures required to achieve the assumed cash flow growth are subtracted.

As of the balance-sheet date, both the fair values less costs to sell and the values in use were higher than the carrying amounts of the cash-generating units. These surpluses react very sensitively to changes in the discount rate, the growth rate and the operating result after taxes in terminal value as key measurement parameters.

Of all the segments, United Kingdom and Netherlands/Belgium exhibited the smallest surpluses of recoverable amount over carrying amount. The goodwill allocated to the segment United Kingdom amounted to €2,968 million as of 31 December 2010. The impairment test showed a recoverable amount which exceeded the carrying amount by £1.1 billion. Valuation of the segment United Kingdom was calculated using a

discount rate of 6.75 % and a growth rate of 1.0 %. An increase in the discount rate by more than 1.21 percentage points to above 7.96 %, the assumption of a negative growth rate higher than 1.53 % or a decrease of more than £85 million in the operating result after taxes in terminal value would result in the recoverable amount being lower than the carrying amount of the cash-generating unit United Kingdom.

The goodwill allocated to the segment Netherlands/Belgium amounted to €2,665 million. The recoverable amount exceeded the carrying amount by €0.9 billion. Impairment would have been necessary if the calculations had used a discount rate increased by more than 0.42 percentage points to above 6.67 %, a growth rate decreased by more than 0.69 percentage points to below 0.31 % or an operating result reduced by more than €61 million in terminal value."

GDF SUEZ SA (31 December 2010, pages 302, 303)

"In accordance with IAS 36, impairment tests are carried out on items of property, plant and equipment and intangible assets where there is an indication that the assets may be impaired. Such indications may be based on events or changes in the market environment, or on internal sources of information. Intangible assets that are not amortized are tested for impairment annually.

Impairment indicators

Property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes to the environment in which the assets are operated or when economic performance is worse than expected.

The main impairment indicators used by the Group are described below:

- external sources of information:
 - significant changes in the economic, technological, political or market environment in which the entity operates or to which an asset is dedicated;
 - fall in demand;
 - changes in energy prices and US dollar exchange rates;
 - carrying amount of an asset exceeding its regulated asset base.

- internal sources of information:
 - evidence of obsolescence or physical damage not budgeted for in the depreciation/amortization schedule;
 - worse-than-expected performance;
 - fall in resources for Exploration & Production activities.

Impairment

Items of property, plant and equipment and intangible assets are tested for impairment at the level of the individual asset or cash generating unit (CGU) as appropriate, determined in accordance with IAS 36. If the recoverable amount of an asset is lower than its carrying amount, the carrying amount is written down to the recoverable amount by recording an impairment loss. Upon recognition of an impairment loss, the depreciable amount and possibly the useful life of the assets concerned is revised.

Impairment losses recorded in relation to property, plant and equipment or intangible assets may be subsequently reversed if the recoverable amount of the assets is once again higher than their carrying value. The increased carrying amount of an item of property, plant or equipment attributable to a reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortization) had no impairment loss been recognized in prior periods.

Measurement of recoverable amount

In order to review the recoverable amount of property, plant and equipment and intangible assets, the assets are grouped, where appropriate, into cash-generating units (CGUs) and the carrying amount of each unit is compared with its recoverable amount.

For operating entities which the Group intends to hold on a longterm and going concern basis, the recoverable amount of an asset corresponds to the higher of its fair value less costs to sell and its value in use. Value in use is primarily determined based on the present value of future operating cash flows and a terminal value. Standard valuation techniques are used based on the following main economic data:

- discount rates based on the specific characteristics of the operating entities concerned;
- terminal values in line with the available market data specific to the operating segments concerned and growth rates associated with these terminal values, not to exceed the inflation rate.

Discount rates are determined on a post-tax basis and applied to post-tax cash flows. The recoverable amounts calculated on the basis of these discount rates are the same as the amounts obtained by applying the pre-tax discount rates to cash flows estimated on a pre-tax basis, as required by IAS 36.

For operating entities which the Group has decided to sell, the related carrying amount of the assets concerned is written down to estimated market value less costs of disposal. Where negotiations are ongoing, this value is determined based on the best estimate of their outcome as of the statement of financial position date.

In the event of a decline in value, the impairment loss is recorded in the consolidated income statement under “Impairment”.

Arrangements that may contain a lease

E.ON AG (31 December 2010, page 69)

“Leasing transactions are classified according to the lease agreements and to the underlying risks and rewards specified therein in line with IAS 17, “Leases” (“IAS 17”). In addition, IFRIC 4, “Determining Whether an Arrangement Contains a Lease” (“IFRIC 4”), further defines the criteria as to whether an agreement that conveys a right to use an asset meets the definition of a lease. Certain purchase and supply contracts in the electricity and gas business as well as certain rights of use may be classified as leases if the criteria are met. E.ON is party to some agreements in which it is the lessor and other agreements in which it is the lessee.

Leasing transactions in which E.ON is the lessee are classified either as finance leases or operating leases.”

Emission Trading Scheme and Certified Emission Reduction

National Grid plc (31 March 2011, page 118)

“Emission allowances, principally relating to the emissions of carbon dioxide in the UK and sulphur and nitrous oxides in the US, are recorded as intangible assets within current assets and are initially recorded at cost and subsequently at the lower of cost and net realisable value. Where emission allowances are granted by relevant authorities, cost is deemed to be equal to the fair value at the date of allocation. Receipts of such grants are treated as deferred income, which is recognised in the income statement as the related charges for emissions are recognised or on impairment of the related intangible asset. A provision is recorded in respect of the obligation to deliver emission allowances and emission charges are recognised in the income statement in the period in which emissions are made.”

E.ON AG (31 December 2010, page 68)

“Under IFRS, emission rights held under national and international emission-rights systems for the settlement of obligations are reported as intangible assets. Because emission rights are not depleted as part of the production process, they are reported as intangible assets not subject to amortization. Emission rights are capitalized at cost when issued for the respective reporting period as (partial) fulfillment of the notice of allocation from the responsible national authorities, or upon acquisition.

A provision is recognized for emissions produced. The provision is measured at the carrying amount of the emission rights held or, in case of a shortfall, at the current fair value of the emission rights needed. The expenses incurred for the recognition of the provision are reported under cost of materials.

As part of operating activities, emission rights are also held for proprietary trading purposes. Emission rights held for proprietary trading are reported under other operating assets and measured at the lower of cost or fair value.”

Centrica plc (31 December 2010, pages 75, 76)

“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 recognized 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 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.”

Customer Contributions

E.ON AG (31 December 2010, pages 120, 121)

“Capital expenditure grants of €739 million (2009: €345 million) were paid primarily by customers for capital expenditures made on their behalf, while E.ON 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 €2,940 million (2009: €3,217 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 2011, page 115)

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

US stranded costs are various generation-related costs incurred prior to the divestiture of generation assets beginning in the late 1990s and costs of legacy contracts that are being recovered from customers. The recovery of stranded costs and other amounts allowed to be collected from customers under regulatory arrangements is recognised in the period in which these amounts are recoverable from customers.

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.

Where revenue received or receivable 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 to future prices 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

Centrica plc (31 December 2010, page 75)

“The acquisition of subsidiaries is accounted for using the purchase method. The cost of the acquisition is measured as the cash paid and the aggregate of the

fair values, at the date of exchange, of other assets transferred, liabilities incurred or assumed, and equity instruments issued by the Group in exchange for control of the acquiree. The acquiree’s identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under IFRS 3 (revised), Business Combinations, are recognised at their fair value at the acquisition date, except for non-current assets (or disposal groups) that are classified as held for resale in accordance with IFRS 5, Non-Current Assets Held for Sale and Discontinued Operations, which are recognised and measured at fair value less costs to sell.

Goodwill arising on a business combination represents the excess of the cost of acquisition over the Group’s interest in the fair value of the identifiable assets and liabilities of a subsidiary, jointly controlled entity or associate at the date of acquisition. Goodwill is initially recognised as an asset at cost and is subsequently measured at cost less any accumulated impairment losses. If, after reassessment, the Group’s interest in the net fair value of the acquiree’s identifiable assets, liabilities and contingent liabilities exceeds the cost of the business combination, the excess is recognised immediately in the Income Statement.”

Concession Arrangements

RWE AG (31 December 2010, page 223)

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

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.”

E.ON AG (31 December 2010, page 77)

“IFRIC 12, “Service Concession Arrangements”

IFRIC 12, “Service Concession Arrangements” (“IFRIC 12”), was published in November 2006. The interpretation governs accounting for arrangements in which a public-sector institution grants contracts to private companies for the performance of public services. In performing these services, the private company uses infrastructure that remains under the control of the public-sector institution. The private company is responsible for the construction, operation and maintenance of the infrastructure. The interpretation has been transferred by the EU into European law and its application is thus mandatory, at the latest, for fiscal years beginning on or after March 29, 2009. The transitional provisions additionally require retrospective application of IFRIC 12. In that context, E.ON has made corresponding reclassifications in the prior-year values, consisting primarily of approximately €0.4 billion reclassified from property, plant and equipment to intangible assets in the network operations in Romania.”

Électricité de France SA (31 December 2010, pages 23, 24)

“1.3.14.1 Accounting treatment

The EDF group records public/private agreements in compliance with standards and interpretations IAS 16, IAS 17, IAS 18, IAS 37, IFRS 6 and IFRIC 4 as appropriate to the specific features of those agreements. IFRIC 12, “Service concession arrangements” was adopted by the European Union on March 25, 2009 and has been applied by the EDF group since January 1, 2010. This interpretation has a limited impact on the consolidated balance sheet and income statement in view of the features of the Group’s concession agreements. 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.

1.3.14.2 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.

1.3.14.2.1 Public electricity distribution concessions

General background

Since the enactment of the French Law of April 8, 1946, EDF 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 EDF may one day lose its status as the sole authorized State concession operator. These contracts cover terms of between 20 and 30 years, and generally use standard concession rules deriving from the 1992 Framework Contract 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 EDF in public electricity distribution concessions in France, whether they are owned by the grantor or the operator, are reported together under a specific line in the balance sheet assets at acquisition cost or their estimated value at the transfer date when supplied by the grantor.

1.3.14.2.2 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. 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.

1.3.14.2.3 French public transmission concession

The assets operated under this concession belong by law to RTE. At December 31, 2009, they were recorded under “Property, plant and equipment operated under concessions for other activities”. Following a change in the consolidation method for RTE, which is accounted for under the equity method from December 31, 2010, these assets are now included in RTE’s equity value in the consolidated balance sheet for 2010.”

Nuclear Fuel

IBERDROLA SA (31 December 2010, page 41)

“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 2010 and 2009 were EUR 681 thousand and EUR 1,377 thousand, respectively (Notes 14 and 37). 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 in each reporting period. The nuclear fuel stocks consumed in 2010 and 2009 amounted to EUR 108,793 thousand and EUR 82,415 thousand, respectively (Notes 14 and 32).”

GDF SUEZ SA (31 December 2010, page 303)

“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.”

Électricité de France SA (31 December 2010, page 28)

“Inventory accounts include:

- nuclear materials, whatever their form during the fuel production cycle;
- fuel components in the warehouse or in the reactor.

The stated value of nuclear fuel and materials and work-in-progress is determined based on direct processing costs including materials, labor and subcontracted services (e.g., fluorination, enrichment, production, etc.).

In accordance with regulatory obligations, inventories of fuel components (new or not entirely consumed) may also comprise expenses for spent fuel management and long-term radioactive waste management, with corresponding provisions or debts in the liabilities, or full and final payments made when the fuel is loaded.

Interest expenses incurred in financing inventories of nuclear fuels are charged to expenses for the period.

Nuclear fuel consumption is determined as a proportion of the expected output when the fuel is loaded in the reactor. These quantities are valued at weighted-average cost of inventories. Inventories are periodically corrected in view of forecast burnt quantities based on neutronic measurements and physical inventories.”

Financial Instruments

Centrica plc (31 December 2010, pages 78 to 79)

“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 recognised and carried at original invoice amount 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 they are classified as current assets. If not they are presented as non-current assets.

(b) Trade payables

Trade payables are recognised at original invoice amount. If payment is due within one year or less they 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 reacquired (treasury shares) are deducted from equity. No gain or loss is recognised in the 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 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 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 Balance Sheet. Available-for-sale financial assets are re-measured subsequently at fair value with gains and losses arising from changes in fair value recognized directly in equity and presented in the 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 Income Statement for the period. Accrued interest or dividends arising on available-for-sale financial assets are recognised in the 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 recognized in equity are removed from equity and recognised in profit and loss. 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 profit or loss.

Impairment losses recognised in the Income Statement for equity investments classified as available-for-sale are not subsequently reversed through the Income Statement. Impairment losses recognised in the 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 in order to reduce significantly a measurement inconsistency that would otherwise arise. 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 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 number 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, and are not within the scope of IAS 39.

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 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 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 approved by the Board of Directors. Further detail on the Group's risk management policies is included within the Directors' Report – Governance on pages 46 to 48 and in note 4 to the Financial Statements.

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 and amortised to the 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 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 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 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 Income Statement.

(i) Hedge accounting

For the purposes of hedge accounting, hedges are classified either as fair value hedges, cash flow hedges or hedges of net investments in foreign operations.

Fair value hedges: A derivative is classified as a fair value hedge when it hedges the exposure to changes in the fair value of a recognised asset or liability. Any gain or loss from re-measuring the hedging instrument to fair value is recognised immediately in the Income Statement. Any gain or loss on the hedged item attributable to the hedged risk is adjusted against the carrying amount of the hedged item and recognised in the Income Statement. The Group discontinues fair value hedge accounting if the hedging instrument expires or is sold, terminated or exercised, the hedge no longer qualifies for hedge accounting or the Group revokes the designation. Any adjustment to the carrying amount of a hedged financial instrument for which the effective interest method is used is amortised to the Income Statement. Amortisation may begin as soon as an adjustment exists and shall begin no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.

Cash flow hedges: A derivative is classified as a cash flow hedge when it hedges exposure to variability in cash flows that is attributable to a particular risk either associated with a recognized asset, liability or a highly probable forecast transaction. The portion of the gain or loss on the hedging instrument which is effective is recognised directly in equity while any ineffectiveness

is recognized in the Income Statement. The gains or losses that are recognized directly in equity are transferred to the Income Statement in the same period in which the highly probable forecast transaction affects income, for example when the future sale of physical gas or physical power actually occurs. Where the hedged item is the cost of a non-financial asset or liability, the amounts taken to equity are transferred to the initial carrying amount of the non-financial asset or liability on its recognition. Hedge accounting is discontinued when the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, no longer qualifies for hedge accounting or the Group revokes the designation.

At that point in time, any cumulative gain or loss on the hedging instrument recognised in equity remains in equity until the highly probable forecast transaction occurs. If the transaction is no longer expected to occur, the cumulative gain or loss recognised in equity is recognised in the Income Statement.

Net investment hedges: Hedges of net investments in foreign operations are accounted for similarly to cash flow hedges. Any gain or loss on the effective portion of the hedge is recognised in equity, any gain or loss on the ineffective portion of the hedge is recognized in the Income Statement. On disposal of the foreign operation, the cumulative value of any gains or losses recognised directly in equity is transferred to the Income Statement.”

*Huaneng Power International Inc.
(31 December 2010, pages 134 to 138)*

“FINANCIAL, CAPITAL AND INSURANCE RISKS MANAGEMENT

(a) Financial risk management

Risk management, including the management on the financial risks, is carried out under the instructions of the Strategic Committee of Board of Directors and the Risk Management Team. The Company works out general principles for overall management as well as management policies covering specific areas. In considering the importance of risks, the Company identifies and evaluates risks at head office and individual power plant level, and requires analysis and proper communication for the information collected periodically.

SinoSing Power and its subsidiaries are subject to financial risks that are different from the entities operating within the PRC. They have a series of controls in place to maintain the cost of risks occurring and the cost of managing the risks at an acceptable level. Management continually monitors the risk management process to ensure that an appropriate balance between risk and control is achieved. SinoSing Power and its subsidiaries have their written policies and financial authorization limits in place they are reviewed periodically. These financial authorization limits seek to mitigate and eliminate operational risks by setting approval thresholds required for entering into contractual obligations and investments.

(i) Market risk

(1) Foreign exchange risk

Foreign exchange risk of the entities operating within the PRC primarily arises from loans denominated in foreign currencies of the Company and its subsidiaries. SinoSing Power and its subsidiaries are exposed to foreign exchange risk on accounts payable and other payables that are denominated primarily in US\$, a currency other than Singapore dollar (“S\$”), their functional currency. Please refer to Notes 22 and 25 for details. The Company and its subsidiaries manage exchange risk through closely monitoring interest and exchange market.

As at 31 December 2010, if RMB had weakened/strengthened by 5% (2009: 5%) against US\$ and 3% (2009: 3%) against € with all other variables constant, exchange gain of the Company and its subsidiaries would have been RMB312 million (2009: RMB357 million) and RMB25 million (2009: RMB31 million) lower/higher, respectively. The ranges of such sensitivity disclosed above were based on the observation on the historical trend of related exchange rates during the previous year under analysis.

As at 31 December 2010, if S\$ had weakened/strengthened by 10% (2009: 10%) against US\$ with all other variables constant, exchange gain of the Company and its subsidiaries would have been RMB121 million (2009: RMB93 million) lower/higher, respectively. The ranges of such sensitivity disclosed above were based on the management’s experience and forecast.

SinoSing Power and its subsidiaries also exposed to foreign exchange risk on fuel purchases that is denominated primarily in US\$. They use forward exchange contracts to hedge almost all of its estimated foreign exchange exposure in respect of forecast fuel purchases over the following three months. The Company and its subsidiaries classify its forward foreign currency contracts as cash flow hedges. Please refer to Note 13 for details.

(2) Price risk

The available-for-sale financial assets of the Company and its subsidiaries are exposed to equity security price risk. The exposure of such a risk is presented on the balance sheets.

Detailed information relating to the available-for-sale financial assets are disclosed in Note 10. Being a strategic investment in nature, the Company has a supervisor in the supervisory committee of the investee and exercises influence in safeguarding the interest. The Company also closely monitors the pricing trends in the open market in determining their long-term strategic stakeholding decisions.

The Company and its subsidiaries exposed to fuel price risk on fuel purchases. In particular, SinoSing Power and its subsidiaries use fuel oil swap to hedge against such a risk and designate them as cash flow hedges. Please refer to Note 13 for details.

(3) Cash flow interest rate risk

The interest rate risk of the Company and its subsidiaries primarily arises from long-term loans. Loans borrowed at variable rates expose the Company and its subsidiaries to cash flow interest rate risk. The exposures of these risks are disclosed in Note 22 to the financial statements. The Company and its subsidiaries have entered into interest rate swap agreements with banks to hedge against a portion of cash flow interest rate risk.

As at 31 December 2010, if interest rates on RMB-denominated borrowings had been 50 basis points (2009: 50 basis points) higher/lower with all other variables held constant, interest expense for the year would have been RMB334 million

(2009: RMB339 million) higher/lower. If interest rates on US\$-denominated borrowings had been 50 basis points (2009: 50 basis points) higher/lower with all other variables held constant, interest expense for the year would have been RMB14 million (2009: RMB14 million) higher/lower. If interest rates on S\$-denominated borrowings had been 100 basis points (2009: 100 basis points) higher/lower with all other variables held constant, interest expense for the year would have been RMB89 million (2009: RMB150 million) higher/lower. The ranges of such sensitivity disclosed above were based on the observation on the historical trend of related interest rates during the previous year under analysis.

The Company has entered into a floating-to-fixed interest rate swap agreement to hedge against cash flow interest rate risk of a loan. According to the interest rate swap agreement, the Company agrees with the counterparty to settle the difference between fixed contract rates and floating-rate interest amounts calculated by reference to the agreed notional amounts quarterly until 2019. In the current year, Tuas Power Generation Pte Ltd. (“TPG”) also entered into a number of floating-to-fixed interest rate swap agreements to hedge against cash flow interest rate risk of a loan. According to these interest rate swap agreements, TPG agrees with the counterparty to settle the difference between fixed contract rates and floating-rate interest amounts calculated by reference to the agreed notional amount semi-annually until 2020. Please refer to Note 13 for details.

(ii) Credit risk

Credit risk arises from bank deposits, credit exposures to customers, other receivables, other non-current assets and loans to subsidiaries. The maximum exposures of bank deposits, accounts and other receivables are disclosed in Notes 33, 18, 17 and 15 to the financial statements, respectively while maximum exposures of loans to subsidiaries are presented on balance sheets.

Bank deposits are placed with reputable banks and financial institutions, including which a significant portion is deposited with a non-bank financial institution which is a related party of the Company. The Company has a director in the Board of this non-bank financial institution and exercises influence. Corresponding maximum exposures of these bank deposits are disclosed in Note 34(a)(i) to the financial statements.

Most of the power plants of the Company and its subsidiaries operating within PRC sell electricity generated to their sole customers, the power grid companies of their respective provinces or regions where the power plants operate. These power plants communicate with their individual grid companies periodically and believe that adequate provision for doubtful accounts have been made in the financial statements.

Singapore subsidiaries derive revenue mainly from sale of electricity to the National Electricity Market of Singapore operated by Energy Market Company Pte Ltd., which is not expected to have high credit risk. They also derive revenue mainly from retailing electricity to consumers with monthly consumption of more than 10,000kWh. These customers engage in a wide spectrum of manufacturing and commercial activities in a variety of industries. They hold cash deposits and guarantees from creditworthy financial institutions to secure substantial obligations of the customers.

The concentrations of accounts receivable are disclosed in Note 5.

Regarding balances with subsidiaries, the Company and its subsidiaries can obtain the financial statements of all subsidiaries and assess the financial performance and cash flows of those subsidiaries periodically to manage the credit risk of loans.

(iii) Liquidity risk

Liquidity risk management is to primarily ensure the ability of the Company and its subsidiaries to meet its liabilities as and when they are fall due. The liquidity reserve comprises the undrawn borrowing facility and cash and cash equivalents available as at each month end in meeting its liabilities.

The Company and its subsidiaries maintained flexibility in funding by cash generated by their operating activities and availability of committed credit facilities.

Financial liabilities due within 12 months are presented as the current liabilities in the balance sheets. The repayment schedules of the long-term loans and long-term bonds and cash flows of derivative financial liabilities are disclosed in Notes 22, 23 and 13, respectively.”

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 the carrying value may 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 (i.e., 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 (i.e., 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.</p> <p>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 (e.g., commodity index or interest rate) • Requires no or little net investment • 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 • Requires or permits net settlement (either within the contract, through a market mechanism, or delivery of 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 when:</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 • 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 when there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required under the contract.</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 (e.g., it does not meet the definition of a derivative on a standalone 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, 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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