IFRS news

Emerging issues and practical guidance*

Supplement – IFRS by industry

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Prospects for refined accounting?

It has been six years since the IASB published IFRS 6, 'Exploration and evaluation of mineral resources'. This long, quiet period for the oil and gas industry has now ended with the publication last month of the discussion paper, 'Extractive activities'. Derek Carmichael and Alfredo Ramirez of PwC's Global Accounting Consulting Services central team examine the DP's key requirements, compare these with new SEC rules and consider how the joint arrangements standard and expected changes in accounting for provisions will affect entities in this sector.

Extractive activities project

The oil and gas industry has been looking for more guidance from standard setters on topics specific to the industry for a number of years. Some proposed answers have been provided by the IASB in the form of the extractive industries DP.

The DP focuses on how to define, recognise, measure and disclose reserves and resources in the financial statements, and how to recognise and measure assets. It also proposes significant increases in the level of disclosure.

The DP proposes working towards a single IFRS for the oil, gas and mining industries, using industry definitions of reserves and resources. It recommends using the SPE and CRIRSCO reserves and resources definitions as a reference point for developing a financial reporting model. Differences remain between the proposed definitions and the new rules introduced by the SEC; these are addressed below.

The DP does not address many of the other accounting issues that challenge the industry, such as commodity contracts, joint working arrangements (including farm-outs, unitisations and production-sharing contracts), revenue recognition (including accounting for overlift and underlift) and decommissioning and restoration activities.

The proposals are largely consistent with those in the draft DP; however, the Board has added further discussion around cost allocation to units of account, impairment and whether disclosures should be audited.

Areas covered:

1 Extractive activities project

3 SEC rules on modernisation

4 Potential impact of ED 9

4 Potential changes in accounting for decommissioning and restoration

Key recognition and measurement proposals

Oil and gas assets would be recognised when the entity has acquired a legal right to explore. Information gained from exploration and evaluation activities, as well as development activities, would represent an enhancement of the exploration/reserves and resources asset.

The asset's unit of account would initially be the geographical area of the exploration right. This will be refined as exploration and development plans are developed, resulting in one or more smaller units of account, generally at the level of the individual oil or gas field. Costs incurred outside this field would be considered separately for impairment and potential derecognition. However, there is then allocation of costs to consider, which apply to the entire geographic area. The DP does not propose whether the asset should be considered tangible or intangible; it only suggests that a separate 'oil and gas asset' is used.

The components-approach used for property, plant and equipment is considered applicable for the components of an oil and gas asset. Such assets would be separate units of account unless they are not commercially separable.

Oil and gas assets would be measured at historical cost, supplemented by disclosure of volume and current value of reserves, rather than fair value. Cost-benefit concerns and the views of users influenced this conclusion.

Proposals for increased disclosure

Disclosure of reserves is currently driven by the requirements of the local regulators, such as the SEC. These disclosures represent a small section of the financial statements and are unaudited. The DP contains proposals for disclosure on:

- Reserve quantities, by commodity, and by country or project;
- Current value or fair value measurement of proved and probable reserves, by major geographical region;
- Production revenues by commodity; and
- Costs.

This would mean a significant increase in the level of disclosure and would take more time and be more costly to implement. These disclosure requirements in an IFRS would fall within the requirements for a set of financial statements and therefore could fall within the scope of audit opinions, depending on the jurisdiction.

Impairment

The DP considers the issue of impairment in more detail than IFRS 6. It concludes that it would not be possible to identify impairment indicators that would be helpful in predicting whether the carrying value of an exploration asset would be recoverable. Impairment would only therefore be assessed when there is a 'high likelihood' that the carrying amount would not be recoverable in full. The option provided under IFRS 6 to make this assessment at CGU level rather than asset level would be removed.

Proposals for increased disclosure

- Reserve quantities, by commodity, and by country or project (where material) including:
  - Proved reserves and proved and probable reserves;
  - Estimation methods and assumptions;
  - Sensitivity analysis to the main economic assumptions (for example, price assumptions, exchange rate assumptions); and
  - Reconciliation of changes in reserve quantities;
- Either current value or fair value measurement of proved and probable reserves, by major geographical region:
  - Standardised measure or fair value estimate;
  - Preparation basis and assumptions;
  - Sensitivity analysis; and
  - Reconciliation of changes in reserve values;
- Production revenues by commodity; and
- Costs, disaggregated in the same way as reserve quantities, with a five-year track record of:
  - Exploration costs;
  - Development costs; and
  - Production costs.

Management might take different views on whether an exploration property should be written down. The DP therefore proposes some additional disclosure measures. These include the separate presentation of exploration properties in the financial statements and, for those assets not written down, an explanation of why management concluded that the amounts should continue to be carried. There is no indication as to the level of detail that would be required for that explanation.

'Publish What You Pay'

The DP also considers the proposals from the Publish What You Pay (PWYP) campaign. PWYP is a coalition of non-governmental organisations campaigning for mandatory disclosure of company payments and government revenues from the oil, gas and mining sector. The IASB project team has suggested further study to see if additional disclosures meet the cost-benefit test. This might include whether these proposals should be applied more widely than just for the extractive industries.

Comment period

The DP is a major step forward in the process to determine whether issues specific to the extractive industries should be added to the Board's agenda, and what the scope of such a project should be. The proposals could have a major impact on accounting and disclosure.

Entities are encouraged to communicate their views on the DP; the comment period ends 30 July 2010.

SEC rules on modernisation of oil and gas reporting

The SEC's amendments to disclosure requirements for oil and gas reserves (the 'Final Rule') modernise the calculation and disclosure of reserves to adapt them to the current market practice and technological advances. They came into effect for annual reports on forms 10-K and 20-F for fiscal periods ending on or after 31 December 2009, and registration statements filed on or after 1 January 2010. Early application of the new rules is not permitted. The Final Rule amends Regulation S-K, Regulation S-X and codifies and revises Industry Guide 2 in Regulation S-K.

There are some significant differences between the proposed IFRS requirements and US GAAP/SEC rules. This section looks at requirements for US-listed entities and compares the frameworks.

SEC changes to definitions

The Final Rule expands the definition of 'oil and gas producing activities' to include sources of oil and gas from unconventional sources, including bitumen oil sands and hydrocarbons extracted from coalbeds and oil shale.

The Final Rule also includes changes to other key definitions. These changes:

- Align reserve definitions with those from the Petroleum Resources management System (PRMS) approved by the Society for Petroleum Engineers (SPE).
- Redefine 'proved oil and gas reserves' by introducing the term 'economically producible'. Economic producibility of oil and gas reserves requires the use of average prices during the prior 12-month period, as opposed to the single-day, fiscal year-end spot price in former SEC rule.
- Define the term 'reasonable certainty' to be at least 90% probability that the quantities actually recovered will equal or exceed the stated volume (consistent with PRMS). The Final Rule considers the 'deterministic estimate' and the probabilistic estimate' as the two alternative methods to estimate reserves.
- Clarify that reserves are determined on the basis of 'reliable' technologies but eliminates the requirement for these to be 'widely accepted'.

SEC changes to disclosure requirements

The Final Rule also changes disclosure requirements. The most relevant changes are to:

- Require disclosure of estimates of proved developed reserves, proved undeveloped reserves and total proved reserves, presented by geographical area and for each country representing 15% or more of a company's overall proved reserves.
- Require disclosure of qualifications of responsible persons for a company's reserve estimates and audits.
- Require narrative disclosure of total quantity of Proved Undeveloped reserves (PUDs) at year end, along with material changes during the year and investments made to convert PUDs. PUDs that have remained undeveloped for more than five years may be included, provided the company discloses the specific circumstances that sustain their inclusion and the progress to develop them.

The Final Rule also allows companies to provide some new voluntary disclosures, such as probable and possible reserves disaggregated as developed and undeveloped, and inclusion of sensitivity analysis.

Disclosure requirements for foreign private investors have been aligned with those applicable to domestic issuers

FASB amendments aligning with the SEC

The FASB issued an amendment in January 2010 to align oil and gas reserve estimation and disclosure requirements the SEC's Final Rule. Accounting Standard Update No. 2010-03 (ASU 2010-3) 'Oil and Gas Reserve Estimation and Disclosure' amends the FASB Accounting Standard Codification (ASC) Topic 932 'Extractive Industries – Oil and Gas'. It is also effective for annual reporting periods ending on or after 31 December 2009.

The ASU 2010-3 also provides other key consideration besides those in the SEC's Final Rule:

- Investments accounted for using the equity method should be considered in determining whether the company has 'significant oil and gas producing activities'.
- Reserve quantities should be separately disclosed for consolidated and equity-method investments. The same level of detail is required for disclosures on equity method investments as is required for consolidated investments.

Impact of the new guidance

The amendments to the SEC and US GAAP guidance aim to improve reserve estimation and disclosures based on changes in practices and technology over the past decades.

The impact is expected to be:

- A reduction in the volatility and seasonality in the level of reserves by using a 12-month average price mechanism to determine the economic producibility of reserves, as opposed to a single-day, year-end spot commodity price.
- Inclusion of bitumen and other non-traditional resources, increasing the volume of reserves (a market for the final product needs to exist if management is to claim reserves for it).
- Inclusion of PUDs with aging over five years could add to

the proved reserve base of companies with large portfolios of undeveloped locations.

- Possible change in the designation of reserves following the new 'reliable' technology terminology.
- Capitalisation of costs relating to non-traditional resources, which may previously have been expensed.
- Effect on the DD&A calculation from 1 January 2010.
- Additional disclosure of probable and possible reserves and reserve sensitivities, and reserve quantities for equity-method investments.

Comparison of US requirements, IASB's DP and IFRS 6

The SEC's Final Rule and ASU 2010-3 differ from IFRS 6 in scope, measurement and disclosures. The guidance in the IASB's extractive activities DP is more comprehensive than the amended US GAAP and SEC literature.

Some of the key differences are:

- The DP suggests one standard for petroleum and mining, rather than separate standards.
- The DP distinguishes between the definitions of reserves and resources.
- The DP requires compulsory disclosure of unproved reserves.
- The DP requires forecast prices, some of which may be company-specific, rather than historical prices for the determination of reserves.
- The DP recommends measurement of mineral and oil and gas assets at historical cost. It does not endorse the full-cost or successful-efforts methods identified in the US GAAP and SEC requirements.
- The DP requires compulsory disclosure of probable and possible reserves and sensitivity analysis to main economic assumptions.

The DP is one of the steps towards the future publication of an IFRS on extractive activities. Although not part of the Memorandum of Understanding on the convergence between IFRS and US GAAP, the project contemplates similar issues as those dealt in US GAAP and SEC guidance. The above differences highlight the gap that remains between the standard-setting bodies.

Potential impact of ED 9, 'Joint arrangements'

The IASB has been working on a replacement standard for IAS 31, 'Joint ventures', for several years. ED 9, 'Joint arrangements', was exposed for comment in September 2007. The key proposals in the ED are expected to appear in the new standard.

The main change proposed by ED 9 is to how joint arrangements are classified. Entities may have an interest in a joint asset, joint operation or joint venture. Classification will be based on the contractual rights and obligations of the parties under the arrangement rather than the legal form of the arrangement as under IAS 31. Joint operations includes joint operations and joint assets. These are joint working arrangements where the parties directly own the assets or a share of the assets and take a share of the output. Each party will account for its own assets and activity, similar to the current accounting for joint assets and joint operations in IAS 31. An arrangement whereby the parties have joint control and an interest in the net outcome of the joint arrangement will be described as a joint venture. Equity accounting will be required for joint ventures, and proportionate consolidation will be eliminated.

The ED is also expected to contain guidance for joint arrangements that include both joint assets/operations and a joint venture. Net-profit royalty arrangements are common in the oil and gas industry and share many of the economic characteristics of joint ventures, and there is some diversity in accounting practice. It is unclear if these will be in the scope of the final standard.

A new standard – incorporating SIC-13, 'Jointly controlled entities non-monetary contributions by venturers' – is expected during the second quarter this year. The standard is expected to be effective for 2013. This seems like plenty of time, but management of oil and gas entities should be looking at their current joint arrangements today to see if structural changes are necessary and possible to maintain their preferred accounting. New joint arrangements should be established considering the new guidance.

Potential changes in accounting for decommissioning and restoration

An ED on IAS 37 proposes potentially significant changes to the measurement of decommissioning and restoration liabilities (see the main edition of *IFRS news*, February 2010, p1). It proposes that an obligation such as asset decommissioning is measured based on the amounts that the entity would rationally pay a contractor to undertake the service on its behalf. Current practice among oil and gas entities is to measure these obligations on the basis of 'least cost to exit' or what it would cost the entity to carry out the decommissioning in the future.

The revised proposals are likely to result in an immediate increase to the provisions recognised on the balance sheets of oil and gas entities today, together with an increase in the related assets (where costs can be included as an element of property, plant and equipment under IAS 16). Borrowing costs will increase and the increased provisions unwind; oil and gas entities may need to gather more information from external parties and consider multiple scenarios or methods of remediation to comply with the new standard.

The IASB originally exposed changes to IAS 37 in 2005. It then debated aspects of the provisions standard and issued a narrow ED in January 2010 addressing only the measurement aspects of the standard. Discussions have confirmed the other key change to provisions accounting: removal of the 'probability' threshold for recognition of provisions. IAS 37 has been applied in practice as requiring the recognition of an obligation when the outflow of economic benefits was 'probable', usually interpreted as having a more than 50% chance of occurring. This will change under the new standard to 'expected', and the recognition threshold will disappear.

The oil and gas industry can have a significant impact on the environment. The costs of restoration and installation are often significant and include costs for dismantlement, demolition of infrastructure, remediation of environmental damage, removal of residual material and, in some cases, environmental clean-up for contamination.

The related obligations are recorded when the damage is caused. Provisions are recorded when there has been an event that results in the probable outflow of economic benefits. Most provisions today are measured as the net present value of the estimated future costs to rehabilitate/restore the disturbance to date. The estimation of costs include both external expenditure and internal costs essential to the closure.

The measurement approach proposed in the ED might result in a change in the measurement of all provisions, including decommissioning and restoration obligations.

The IASB considers that estimates of a third-party contractor price are more objective evidence of the value of an obligation than the entity's own cost to fulfil the same obligation. Implicit in the use of a 'market' price for a contractor is the inclusion of direct and indirect costs and profit margin that a contractor would require. This price is likely to be higher than the entity's own cost to perform a similar service. The new measurement criteria in the ED might result in a significant increase in decommissioning obligations. It might also have the odd result of the recognition of income in the future when the obligation is extinguished and the entity compares its actual restoration/dismantling costs (presumably lower than market rates) against the liability recorded.

The comment period for the ED was originally scheduled to end on 12 April 2010; however, this been extended to 19 May 2010 to allow interested parties more time to finalise their comments.