

The Value of Oil and Gas Reserves

SEC Definitions of Proved Oil and Gas Reserves (Regulation S-X, Article 4)

So much has recently been heard of these SEC definitions that we felt it would be useful to record precisely what they are. We realise that some readers of Forum will be able to quote them, probably in their sleep, line by line, but there may be others who will be surprised to find how uncomplicated they seem to be, at least until the experts set about complicating them. At any rate, here they are: subsections (2), (3) and (4) of the Definitions under Reg. 210.4-10 which 'prescribes financial accounting and reporting standards ...pursuant to Section 503 of the Energy Policy and Conservation Act of 1975 (EPCA) And section 11,c of the Energy Supply and Environmental Coordination Act of 1974 as amended by section 505 of EPCA.'

(2) *Proved oil and gas reserves.* Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive

on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the 'proved' classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

- (a) oil that may become available from known reservoirs but is classified separately as 'indicated additional reserves';
- (b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
- (c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
- (d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

(3) *Proved developed oil and gas reserves.* Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as 'proved developed reserves' only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

(4) *Proved undeveloped reserves.* Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates, for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.



Peter Nicol considers the accounting of reserves

Reserves accounting has hit the headlines in recent months following Royal Dutch/Shell's announcement regarding its 'proved reserve recategorisation'. A number of other companies have also announced significant changes in their published reserves including El Paso, Nexen and Forest Oil. In addition there has been the widely publicised debate around the reserves booking for the Ormen Lange gas development in Norway and whether Norsk Hydro

and BP will be able to reflect the same reserve numbers in their annual US financial filing (20F) as in their Annual Reports.

There are a number of debates. The adequacy of company reserve disclosure, the definition of the reserves which are disclosed, the interpretation of the existing US Securities and Exchange Commission (SEC) rules and consequently whether this is an industry generic issue or limited to certain specific companies or both. In this discussion we will look at the issues from the standpoint of an investor in the companies.

There are two investor standpoints in financing companies – the viewpoint of a lender and the viewpoint of an equity investor in the corporation. The discussion will concentrate on the viewpoint of an equity investor, but it is worth highlighting that equity investors and debt investors may have very different preferences in terms of reserves. Even assuming that both sets of investors are considering the same P50 (proven and probable) reserve estimate their preferences in terms of the distribution and probability of reserve estimates could well be different. The debt investor would be more concerned to ensure that the P90 (proven) level gave comfort for the repayment of principle and interest, whereas an equity investor may be prepared to take more risk here if there were greater potential upside from the P50 to the P10 level (proven probable and possible). So even when there is agreement on the most likely reserve estimate, there will be different priorities and preferences from different user groups. The remainder of this discussion will be taken from the viewpoint of an equity investor or shareholder, the ultimate owners of the company and, in turn, the underlying reserves.

The Adequacy of Company Reserve Disclosure

Analysts and investors looking at the international oil companies tend to spend a disproportionate amount of time on the upstream compared to gas and power, refining and marketing and chemicals. There are two reasons for

this: financial disclosure is greater for the upstream and secondly the upstream in recent years has accounted for the majority of the assets and the highest (book) returns within the industry. In simple terms, investors buy oil companies for their oil.

One difficulty in analysing an oil company balance sheet is that it does not reflect value. The balance sheet records the historic costs associated with drilling for, development of, or acquisition of oil and not the value of the oil and gas interests. The reserve disclosure while not perfect helps investors to fill this information gap.

Different Reserve Disclosures

The Penwell International Petroleum Encyclopedia gives a description of reserve definitions on its web site <http://orc.pennnet.com>. The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) published updated reserve definitions in 1997 to include the use of probabilistic evaluations. The SEC definitions tend to be based (albeit not exclusively) on deterministic methods. Deterministic methods provide a single best estimate of reserves based on geological, engineering and economic data. Probabilistic methods generate with similar data a range of estimates and their associated probabilities – proven (P90), proven & probable (P50), proven probable and possible (P10).

There are a number of reserves disclosures and standards around the world with P50 reserves disclosure allowed in the UK, Norway, Canada and Australia amongst others. However, the most widely used disclosure is that required by the US SEC due to the importance of US capital markets and the fact that most major private oil companies have a US listing. Under the US disclosure companies are required to report their 'proved' reserves similar to, but not equivalent to, proven or P90 reserves. While the SEC will accept probabilistic reserve estimates if professionally prepared, the difficulties arise under the SEC definition of what constitutes 'reasonable certainty'. In the USA deterministic reserves remain the

most common method as it satisfies the SEC proved reserve definitions in establishing 'reasonable certainty' where e.g. there is no known hydrocarbon-water contact or there are untested fault blocks that may be dry when drilled.

European and Australian based companies will adopt IFRS (International Financial Reporting Standards) from January 2005, but at present there is no IFRS that specifically addresses the accounting for the exploration and evaluation of mineral resources. In addition, mineral rights and mineral resources including oil and natural gas are excluded from the scope of IAS 16 (Property Plant and Equipment).

A move to International Accounting Standards will provide an opportunity to harmonise, re-evaluate the data presented and, in the view of some, update the information relative to that currently presented under US GAAP (Generally Accepted Accounting Principles). However, the fact remains that the market will remain dependent on the requirements under US disclosure and the work of the SEC. It is debatable whether a number of non-US companies would be as forthcoming with information if it were not for the requirements of their US listing, so even if there are limitations with the data presented, it provides a useful source of information for the market place.

As mentioned above, US disclosure requires proved reserves, which for simplicity we will take as equivalent to the P90 reserves. The complaint is that this does not reflect economic reality or the reserves that the company is using when formulating its internal plans and projects. This requires the company to maintain two reserve data bases (the real reserves and those being allowed for financial reporting) and paints a conservative view of the company's position. Investors are interested in the real economic data and, as shareholders, have no wish to see companies spend money unnecessarily and would broadly concur with these complaints.

However the surprise from an investor standpoint is the extent and magnitude of the downward revisions

to these 'conservative' reserves. Press reports suggest that the recent SEC enquiries were sparked off in light of companies booking reserves, but then failing to increase production, meet production targets or carry out further work on the announced 'discoveries'. Presentations by petroleum engineering consultants Ryder Scott appear to support this contention.

The conundrum from the investors' standpoint is whether the discrepancy between the reserves and the production represents timing differences (the lag between booking and production coming on-stream), over-optimism on the reserve estimates, or a problem with the existing reserves with higher decline rates or lower recovery factors than previously realised.

There is also the surprise that assuming that the proved reserves have been added conservatively (without probabilistic or portfolio assumptions) then the likelihood that the total reserve base should have had to be revised down at all should have been very low. This undermines the original claims of conservatism. If this problem were just affecting small companies with one or two assets then it would be more easily understood, but the fact that larger and more diversified portfolios have also been impacted with significant (which the SEC is believed to define as greater than 10 per cent) changes is very surprising. The conclusion must be that there are certain issues related to specific companies.

SEC Rules Interpretation

The SEC has also come under fire from a number of interested parties for its decision to tighten its interpretation of the rules and to disallow some common industry techniques in reservoir evaluation. 'Lowest known hydrocarbons' and the use of 3D seismic are the most obvious examples. This does appear to be an area in which the SEC is being unduly conservative or where its rules (dating back to 1978) need to be updated.

The different levels of reserve booking for the Ormen Lange gas field development in Norway have

received considerable press, industry and investor interest. In terms of economic reality, it is not a case of some companies being more conservative than others by 'booking' lower reserve numbers for the financial accounts. The five partners (Statoil, Norsk Hydro, BP, Royal Dutch/Shell and ExxonMobil) have all agreed to a development plan and to finance their respective shares based on a common view of the P50 reserves and associated development costs. If the lower 'conservative' reserve bookings turned out to be correct, the economic disaster would afflict all, namely that all five partners had invested \$12bn in an uneconomic project.

“A simple adjustment to the existing SEC disclosure would eliminate much of the debate”

However this issue has highlighted another industry practice of when and how companies book reserves. The practice of 'smoothing' reserve bookings in order to show steady reserve growth can be just as misleading to investors as over-booking. While companies may state that the P50 reserve estimate is the most likely, the industry does not appear to book 100 per cent of the P90 reserve level once a field is recognised, preferring instead to recognise different and usually increasing volumes over time. 'Smoothing' effectively understates the reserve volumes compounding the problems of a reserve definition that the industry is complaining is too conservative in the first instance.

An Industry or a Company Problem

It would appear that there are industry generic issues – the definition of reserves to be disclosed, the definition and interpretation of reserve bookings and the timing of reserve booking – all come to mind. However as pointed out above, the magnitude of certain reserve restatements suggests that there are also a more limited number of company specific issues, which

need to be addressed by the companies concerned. The question is 'what should companies have to disclose?'

What Should Companies Disclose?

A simple adjustment to the existing SEC disclosure would eliminate much of the debate on which company is conservative or aggressive in its reserve booking. Norsk Hydro and Pemex both detail the complete list of fields and the reserve quantities associated with their overall reserve booking. Companies will comment that this reserve information is confidential or cannot be disclosed under the terms of licence/operating or partner agreements. However this is debatable when the information being disclosed is not the 'real' P50 reserve estimates (it's the 'proved' or P90 reserve estimate) and the financial or fiscal terms are not being disclosed. In addition, given that many Western governments and NGOs are pressing for greater disclosure by the industry of its financial and tax payments to developing countries, this may prove to be a useful adjunct helping the companies in their argument for greater disclosure.

Amongst the many issues that the International Financial Reporting Standards will have to address are whether the disclosure of reserves should be supplemented with greater financial and value disclosure as reserves have very different values depending on their location, maturity and the fiscal regime. In terms of the volumetric disclosure, the reconciliation of annual reserve movements already presented under US disclosure would form a strong framework from which to start. However the disclosure could either be augmented to disclose movements in P10 and P50 reserve estimates as well as movements in proved (or P90) reserves.

Some may make the case that the P50 are the best estimates of reserves and hence are the 'real' reserves and that only this should be disclosed. However from an investors' standpoint there is an important overlay to the P50 levels which it would be helpful to disclose – namely the commerciality or likelihood of commerciality of

these P50 reserve estimates. While P50 reserves may be produced many years into the future, there is a difference in the perception of value in many investors' minds between those P50 reserves associated with a development which is already underway or producing and a development which still may be many years from commerciality and final investment decision. It would be useful to put some economic criteria around the definition of P50 reserves rather than just that they exist volumetrically.

The SPE/WPC or the proposed UN framework for reserve definitions may be the means of determining the appropriate level of disclosure in terms of the number of definitions disclosed and the appropriate criteria behind those reserve disclosures. A balance will need to be struck between simplicity, the extent of the reporting burden to be placed on companies and the usefulness of the information.

Finally, while many may think that a move to P50 will solve many of the current problems by moving to a more realistic level of reserves, any change will necessitate a different mind set from both investors and the reporting companies. Larger companies have used the inherent conservatism of P90/proved reserves to demonstrate steady growth in the reserve base over the longer term. While this may understate the 'true' picture or value of these companies in any one snapshot, it does lead to the impression that large resource companies are sustainable and provide steady long-term growth. The challenge in moving to a P50 reserve disclosure is that reserve movements should be equally likely to increase or decrease. Investors will have to become used to greater volatility of reserves while companies will need to prove that they can indeed grow over the longer term.



Brian Rhodes and Andy Crouch define the valuation of reserves

The announcement by a number of high profile companies this year that they were revising the proved reserves being reported to the US Securities Exchange Commission (SEC) caused shock waves to pass through the industry. Other companies then looked hard at their own numbers and in some instances also amended their proved reserve statements. The impact has wider ramifications than for the individual companies. The stockbrokers, their analysts and institutional fund managers, let alone the shareholders themselves, do not know what to make of it all, or who has correctly stated their proved reserves, if indeed it is possible really to be correct.

Arguably one of the main results from these downgrades has been the acknowledgement that the basis for reserves numbers and even the terminology is not uniformly understood. At the outset then it is worth first reminding ourselves what the term 'reserves' means. By definition reserves are:

- i) Discovered
- ii) Recoverable
- iii) Commercial
- iv) Remaining

All four factors must exist. Reserves are also only ever 'estimated', never 'determined' due to the uncertainty that comes with the territory of working with nature and physical parameters you cannot see.

We must then consider the various frameworks for reserves estimating. Reporting reserves to the SEC is currently the biggest area of debate, due to the impact that it has on the financial world. The SEC has its own set of definitions which have remained unchanged since first written in 1978, but these deal only with Proved Reserves as they should be calculated under those definitions, which state:

Proved oil and gas reserves are the estimated quantities of crude oil,

natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Whether they are right or wrong, or as is widely suggested whether they need to be updated due to technological advances or other reasons is not debated here. It is a simple fact that companies can and still do report according to those definitions. Perhaps the problem is that the SEC limits the amount of information that the companies can release, and that the information that can be released is too restrictive to demonstrate adequately their business. The result may be that companies end up testing the limits of the definitions.

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The more-widely used industry definition is the Resource Classification System generated jointly by the Society of Petroleum Engineers (SPE), World Petroleum Congress (WPC) and the American Association of Petroleum Geologists (AAPG). It deals with all assets from undrilled prospects to Proved Reserves and its use as the industry base would allow companies the opportunity to demonstrate adequately the extent of their assets.

One problem we currently face is that reserves reported under the SPE/WPC/AAPG Proved Reserves definition can be different to those under the SEC's. While the SPE Reserve definitions wording for Proved

Reserves is essentially the same as that of the SEC it differs in its use of 'current economic conditions', which allows for averaging of historic prices and costs that are 'consistent with the purpose of the reserve estimate'. The SEC requires prices to be used at the date of the reserves estimation, so even when we see the term Proved Reserves quoted, we are not necessarily looking at the same thing and, of course, Proved Reserves stated during a high oil or gas price may be much less when estimated under a lower price.

The fundamental requirement of both the SEC and SPE/WPC definitions is that for Proved Reserves there must be 'reasonable certainty' that the volumes will be recovered. Although the recent high profile revisions made by one of the companies affected a number of its assets, focusing on just one of those assets can show large differences of opinion. In this specific instance some of the joint venture partners have also made their own public statements to defend their positions; one stated '... [the company] has not made any changes to the ... reserves it has placed with the SEC...'; and another advised 'We are completely confident of the reserves we have booked'. Yet when each of these individual companies' net Proved Reserves is grossed up to a full field basis the result is a fourfold variation. All of these are supposedly estimated using the SEC's Proved Reserves definitions which are worked under the banner of 'Reasonable Certainty'. However, it would appear that there is a wide range of uncertainty, which looks like anything other than 'Reasonable Certainty'. This is just one field, so how are readers of this information going to make judgements on investment in all of the assets of these companies involving vast sums of money with such a diversity of numbers? Remember that it has been the SEC's goal to provide investors with the ability to compare companies on a like-for-like basis.

From the companies' perspectives, the decision to invest in the development of any field would not be made on the sole basis of the Proved Reserves

disclosed under SEC definitions, nor would a government necessarily approve the development on this basis alone. The companies would have made that decision on the basis of their 'best estimate', or however they refer to the outcome that they expect to be the more likely than not. These 'best estimates' will have been tested for robustness with a series of sensitivity tests looking at all of the fundamentals of ultimate recovery, depletion scheduling, capital costs, operating costs, sales prices, inflation and exchange rates, before the company and then the collective joint venture decides to make the investment. In the case of the specific field alluded to above, this is close to a US\$10 billion investment decision. It is unlikely then to be a decision taken lightly or in the face of the implied diverse Proved Reserves element.

“Current trends show that the F&D costs across the industry are increasing”

Perhaps there is reason to suggest that the better reporting criteria are those that reflect the level at which the investment decisions are made, since that is the level at which shareholder funds are invested. The case presented by the above field's fourfold variation in Proved Reserve volumes, would suggest that there is perhaps more certainty among the owners around the 'best estimate' reserves level upon which the joint venture has made its investment decision.

However, with all of this in mind, how does the financial world look at the companies and what metrics do they use to measure and compare? Analysis of financial data is of course historic in nature and the analysts use other measures such as Reserves Replacement Ratios (RRR), allocation of Proved Reserves between Proved Developed (PDP) and Proved Undeveloped (PUD), Reserve life, and Finding and Development costs (F&D cost) to look at companies. These can reveal important trends when present-

ed year-on-year and offer insights into the future potential of the companies. But at the same time these numbers are related only to the Proved volumes and thus in themselves can lack information which displays the real future of the companies from the overall resource base.

What do these metrics show us about the companies? The analysts tend to want to break them down into their peer groups (e.g. Five Sisters, Large E&P, US Integrateds, and so on) for comparison purposes and certainly this helps to see how the groups are performing relative to one another and how the companies within each group compare with their peers. However, for US reporting companies this analysis is based solely on Proved Reserves. A company could have a dynamic year with the drill bit but the volumes to be included in any company analysis may only be considered once they are booked as Proved Reserves, which could take several years. The phasing of Proved Reserve recognition and related capital costs could therefore distort a company's F&D costs. It may also be inconsistent with other reported actions. As noted in the example above, a fourfold variation in the Proved Reserves for a US\$10 billion development would create incompatible comparative F&D analyses for the same field.

Current trends show that the F&D costs across the industry are increasing, albeit some of this may be as a result of declining volumes of lower classified resources/reserves which can be elevated to the Proved category. While it is agreed that it is important to know the capital outlay for the future since this can point to higher capital employed which can mean lower returns, this in itself is linked to oil price. The period from 1990 to 1999 showed an average Brent price of around \$19.70/barrel, but this has increased since then with the period 2000 to May 2004 averaging over \$27.3/b with 2004 itself over \$33/b, and record prices at the beginning of June. Thus, while the recent trend for increasing F&D appears to be a negative factor, the oil price has worked in the opposite direction with many

companies reporting record-breaking profits.

Similar variations in RRR and reserve life would also occur as these are also determined from only the Proved Reserves. However, the one metric where more can be learned is from the ratio of PDPs to PUDs since this is simply the split of the Proved Reserves.

Movement year-on-year in this regard, especially in an increasing upward trend of PUDs, could be a clear adverse indicator for a company since capital is required to develop these assets and therefore re-categorise them as PDPs. Also it should always be the intent of the company, at least in terms of oil reserves (gas reserves may be developed in line with long-term sales contracts) that once reserves have been classified as PUDs they should be elevated to PDP status in a reasonable time frame. Proved oil Reserves remaining as PUDs for a significant period of time are (and should be) at risk of downward revision, subject of course to allowance for other factors such as OPEC constraints and limited pipeline capacities.

The effect of changes in oil (or gas) prices on reserves bookings is also worthy of comment. Companies invariably have a mixture of petroleum legislations in which they have their operations, which will mix tax and royalty regimes with production sharing contracts. A changing oil price has opposite effects in these regimes – a higher oil price can mean higher proved reserves in a tax and royalty regime, whereas in a production sharing contract the higher price means lower entitlement volumes, which is the proper way to present such contracts. Thus a significant shift in oil price at any time during corporate reporting periods could make significant changes both up and down, depending on the legislation and direction of price, while in reality the gross volumes themselves may be no different.

Thus, in summary, we must ask ourselves whether the analysts have sufficient data to measure company performance properly. Certainly they are only looking at one specific element of the business (the Proved

Reserves) albeit this is the area where, in many cases, most of the value can be attributed and thus a valuable metric in itself. However, several of the other metrics are inter-dependent and determined only from the Proved component of the total resource base and thus may not provide the full assessment of company performance. Can we be sure then that the results of their analysis can be taken as ‘reasonable certainty’?

The SPE states ‘Estimation of reserves is done under conditions of

uncertainty’. In an ideal world the aims should be to do our best to if not reduce then certainly quantify that uncertainty. GCA has many years experience in estimating resources and reserves and classifying them according to both the SEC and the SPE/WPC/AAPG definitions. This includes not only the calculations themselves but also advising on internal company guidelines and on internal processes to ensure that companies understand and appropriately categorise their hydrocarbon assets.

During the recent oil price ‘crisis’ it was ironic that the UK’s Chancellor of the Exchequer, while castigating OPEC’s members for failing to produce enough oil to bring prices down, ignored the UK’s role since the early 1990s as one of the top-10 global oil producers. He also failed to admit that the now-declining UK oil output results from a less than pro-active government policy for the country’s hydrocarbons industry.

country’s massive hydrocarbons industry grossly understates the economic and political significance for the UK of this overwhelmingly dominant sector in the country’s energy economy. Since 1974 some 4500 millions tons oil equivalent of oil and gas have been produced, equal to the equivalent of over 75 per cent of the UK’s *total* energy use during this period. Over the five years to 2003 their share was 95 per cent.

The Importance of Hydrocarbons Production to the UK

Apart from the long-term security of energy supply which indigenous hydrocarbons production has given to the UK in a world of uncertainty over energy supplies, the favourable impacts of the oil and gas industry on the country’s GDP, on direct and indirect employment and – most of all – on its balance of trade has been formidable. Indeed, net export earnings from indigenous oil and gas over the five years from 1998 have contributed almost £6000 million per year to the balance of trade, while the value of the energy import substitution effect has averaged £9000 million per year. This £15,000 million per year net external payments’ contribution from indigenous hydrocarbons’ production can be compared with the average annual balance of trade deficit over this period of £30,000 million per year. Without oil and gas this deficit would have been 50 per cent greater.

Given these political and economic advantages for the UK from its hydrocarbons industry, the absence of calculations in the Energy White Paper of the resource costs which will emerge

Personal Commentary

Peter R. Odell

Initially, this reflected the government’s unwillingness to make economically worthwhile public investments in oil and gas to supplement the private sector’s effort. More recently, however, it has also reflected the government’s obsession with a perceived need to constrain carbon fuels’ use and to stimulate ‘green’ energy production with generous subsidies.

Last year’s Energy White Paper (reflecting the PIU’s earlier Energy Report to the Prime Minister) epitomised the government’s anti-oil and gas attitudes. There were, indeed, only 60 lines of text on the UK’s world-scale upstream hydrocarbons industry in the White Paper – from a total of 5000 lines in the document!

Such perfunctory treatment of the