Exhibit 85

Restricted to Shell Personnel Only **EP 2003-1100**

Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

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SHELL INTERNATIONAL EXPLORATION AND PRODUCTION B.V., RIJSWIJK

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KEYWORDS

Petroleum Resource Volumes, Guidelines, Reserves, Scope For Recovery, SFR, FASB, SEC

1. INTRODUCTION

Petroleum Resources represent a significant part of the Group's upstream assets and are the foundation of most of its current and future upstream activities.

The Group's EP business depends on its effectiveness in finding and maturing Petroleum Resources to sustain itself and drive profitable production growth. To aid systematic resource management, the volumes concerned are classified according to the maturity or status of their associated development (project) and operational (production) activities.

The Group's Petroleum Resource Volumes and changes to them, both actual and planned, are reported to the EP Executive regularly. Proved Reserves have a direct influence on net income, since they are used directly in the calculation of capital depreciation. Under the financial accounting rules of the United States Securities and Exchange Commission (SEC), Proved Reserves must be disclosed externally and therefore they are subject to internal controls and external review procedures. These external disclosures represent the only information on Petroleum Resource Volumes that is reported consistently by all major international oil and gas companies. Consequently, disclosed Proved Reserves figures are subjected to intense scrutiny by external analysts. Actual and projected performance in the replacement of Proved Reserves is one of the key factors taken into account by analysts when issuing advice to investors. This advice can directly influence the share price.

This document describes the Group's Petroleum Resource Volume classification system. In relation to Proved Reserves, it is intended to comply with rules set by the SEC and it serves as a reference in the reserves reporting and control processes, as applied by the asset holders. Additional controls that apply at the Group level are documented elsewhere (SIEP 2003-1102, Reference 3).

Information on the requirements for the collection of data for internal reporting and external disclosure will be addressed by the second part of these guidelines (SIEP 2003-1101, Reference 2). Detailed reporting requirements are communicated annually in a letter from EP Planning.

The present (2003) version of this document has been reformatted compared with previous versions, with the intention of improving clarity. It is stressed that, with the exception of the items summarized below, no changes to the internal rules for Petroleum Resource Volume accounting have been made.

Material changes to the volume of Proved Reserves reported by the Group are neither expected nor intended as the result of issuing these revised guidelines.

Substantial changes compared with previous guidelines:

1. The trigger for booking reserves for major projects has been refined from VAR3 to FID, or other public demonstration of commitment to proceed with the project. Refer to section 2.4.3

2. It is clarified that binding Heads of Agreement ("HOA") for sales contracts are a (minimum) necessary condition for booking major gas reserves that rely on the creation of access to market (e.g. those reliant on negotiation of LNG sales contracts). Refer to section 2.4.3.

2. PETROLEUM RESOURCE VOLUME CLASSIFICATION SYSTEM

2.1 Introduction

In general, all companies, authorities and other organizations that are involved in oil and gas exploration and production activities use a system for tracking Petroleum Resource Volumes as they mature from undiscovered prospects through to producing assets. All such systems aim to achieve similar objectives, but each is unique in terms of the nomenclature that is used and in the definition of certain terms. Often, the most fundamental differences stem from the differing areas of focus of the organizations that developed the systems: governmental organizations tend to address all aspects of technically recoverable resources, however notional, whereas commercial enterprises tend to concentrate on those elements that can most readily be monetized.

Thus, across the industry, a range of classification systems exists, each being tailored to the needs of the specific organizations that use it. This may introduce confusion and misunderstanding when different organizations discuss aspects of petroleum resource management, particularly when similar terms have different definitions under different systems (for example, the precise meaning of the term "reserves" can vary substantially between systems).

To help the industry avoid such confusion, several independent bodies have proposed the use of uniform classification systems. Probably the most widely known is that proposed jointly by the Society of Petroleum Engineers and the World Petroleum Congress and subsequently adopted by the American Association of Petroleum Geologists (SPE / WPC / AAPG, Reference 6).

The Group continues to use its own classification system, developed over a number of years and tailored specifically to the needs of the Group's business. The system will continue to evolve over time as the needs of the business change.

It is important for all individuals involved in the classification and management of the Group's Petroleum Resource inventory to realize that the system is unique to the Group, but also that it can be translated readily into the SPE system (and most other systems) should the need arise.

It is also important for all individuals involved in the preparation of Proved Reserves estimates to ensure compliance with the definitions and rules set by the United States Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB), as expressed and interpreted in these guidelines.

2.2 Overview

The Shell Petroleum Resource Volume classification system is summarized in Figure 1. It provides a framework for classifying the Petroleum Resource Volumes that are associated with a project as it matures from an undiscovered prospect through to a producing asset. Petroleum Resource Volume estimates are subject to uncertainty, reflected in the diagram through the use of columns expressing the Low, Expectation and High values of the estimate. A link to the SPE reserves classification (Proved, Probable, Possible) is also provided for the purpose of illustration.

Shell Notation	**Low**	**Expectation**	**High**
SEC Notation (reserves only)	**Proved**	**n.a.**	**n.a.**
SPE Notation	Proved	Proved plus Probable	Proved plus Probable plus Possible
Shorthand notation	1P	2P	3P

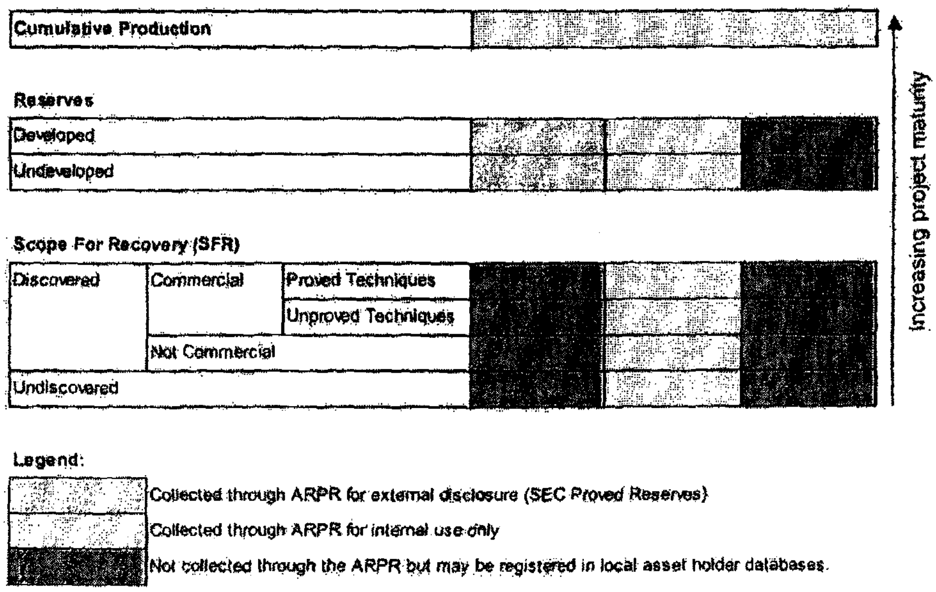

Figure 1: Overview of Shell Petroleum Resource Classification System

For internal Group purposes, Expectation estimates of Petroleum Resource Volumes must be reported to EP Planning through the annual Resource Volume data submission. Proved Reserves are required in addition to this for external disclosure.

In the following sections, a definition is provided of each category in the classification system (section 2.3), together with factors to be taken into account when Resource Volumes mature from one category into another (section 2.4).

A revised Petroleum Resource Volume classification system will take effect from 31.12.2003. This is described in Appendix 5. Whilst changes to Resource Volumes during 2003 will be reported according to the existing classification system, Resource Volume balances at 31.12.2003 will need to be subdivided into the revised classification system. These will then form the opening balances for the reporting of changes that occur during 2004.

2.3 Petroleum Resource Volume Definitions

In this section definitions are provided for each Petroleum Resource Volume category. Several ancillary and related terms are also defined in Appendix 4.

2.3.1 Petroleum Resource

A Petroleum Resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located within the company's current exploration and production acreage.

Petroleum Resource Volumes are reported as the quantities of crude oil, natural gas and natural gas liquids that will be available for sale upon production. The volumes are reported on the basis of Group share. It is recommended that asset holders also maintain data on a 100% field basis.

Petroleum Resources are subdivided into two broad categories: Scope For Recovery (SFR) and Reserves.

2.3.2 Scope For Recovery (SFR)

SFR is any Petroleum Resource Volume associated with a project that is not yet sufficiently technically and commercially mature to qualify as reserves.

There must be an expectation that the project could mature, based on reasonable assumptions about the success of further appraisal, emerging technology development, cost reduction strategies, marketing efforts, improvement of terms and conditions and/or any other issue that might prevent the project progressing to development sanction (i.e. Final Investment Decision, "FID").

SFR is reported as a single best technical estimate, multiplied where necessary by the probability that the project will materialize. The objective at all times is to reflect as accurately as possible the Resource Volumes that eventually will be available to the Group in the expectation case.

The economic evaluation should take into full account any future pre-investment costs that are required to reduce technical uncertainty.

The further breakdown of SFR as "Undiscovered" or "Discovered" is as follows:

SFR Undiscovered

Resources that could be contained in an undrilled potential accumulation and which would be recoverable by any process that has been demonstrated to be technically feasible elsewhere, under similar conditions. Development should be expected to be commercially viable.

The expectation value of SFR Undiscovered should be reported as the product of the Mean Success Volume (MSV) at commercial cut-off and the corresponding Probability of Success at commercial cut-off (POS) (see Appendix 4.2).

Following drilling, the pre-drill estimate of Undiscovered SFR should be updated to take account of the drilling results and, in the case of a discovery, the economics of development should be re-assessed. At this point the resource is either discarded or reclassified to one of the SFR Discovered categories.

SFR Discovered

Resources that are contained in an accumulation in which the presence of movable hydrocarbons that are potentially of interest for development has been established through drilling and, where necessary, through associated data gathering activities.

Please refer to the definition of "discovery", section 2.4.2 below.

SFR Discovered may be held in one of three sub-categories: Non-Commercial SFR, Commercial SFR by Proved Techniques or Commercial SFR by Unproved Techniques.

Non-Commercial SFR

Resources that are associated with a discovered accumulation and with a project that is evaluated as having a negative Net Present Value (NPV) of development at the prevailing Group premises or for which there are clear commercial obstacles to development that appear to be insurmountable in the 5-year plan period.

To avoid retaining unrealistic volumes in the classification, the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical Cost below a ceiling that is advised annually by EP Planning.

Non-Commercial SFR is reported in order to retain an indication of the discovered resources that could become commercial with a change of circumstances (e.g. an increase in oil price, a change in tax regime, improvement of technology, development of a gas market, discovery of additional volumes in the area that could form a critical mass for development).

SFR Discovered should be categorized as Commercial unless there is clear demonstration to the contrary. In other words, when commerciality is uncertain, the Resource Volumes should be allocated to a Commercial category pending further evaluation (which may result in the volumes being reclassified as Non-Commercial).

Commercial SFR by Proved echniques

Resources that are associated with a discovered accumulation and with a project that (a) uses a recovery process or technique which has been demonstrated to be technically feasible in the resource concerned or under analogous conditions and (b) is expected to be Commercial.

Commercial SFR by Unproved echniques

Resources that are associated with a discovered accumulation and with a project that uses any recovery process or technique which has not been demonstrated to be technically feasible (under conditions applicable to the area or field) and which requires future laboratory tests and field trials (pilot) in order to establish this feasibility. There must exist the reasonable expectation that, once the necessary work has been completed to demonstrate the technical feasibility of the project, it will be Commercial.

2.3.3 Reserves

The term "Reserves" describes any Petroleum Resource Volume that is associated with a producing asset or with a project that is technically and commercially mature to the extent that funding for the project is reasonably certain to be secured.

Two estimates of Reserves are captured in the annual reporting of Petroleum Resource Volumes: Proved Reserves and Expectation Reserves. Estimates of Reserves (both Proved and Expectation) are subdivided into quantities that have been developed to date (Developed Reserves) and those that will be addressed by planned or ongoing development activities (Undeveloped Reserves). Each of these categories is described below.

Expectation Reserves

The most likely estimate of the Resource Volume remaining to be recovered from a project that is technically and commercially mature, or from a producing asset.

If probabilistic techniques are used in reserves estimation, the Expectation Reserves are the probability-weighted average of all possible outcomes.

If deterministic techniques are used in reserves estimation, the Expectation Reserves correspond to the most likely estimate of future recovery.

In general, a field should not have Expectation Reserves allocated to it unless and until the necessary criteria for booking (at least some) Proved Reserves have been met: the criteria for categorizing resource volumes as "Reserves", rather than "SFR", apply in principle to all categories of Reserves and generally a field should not be allocated Expectation Reserves but no Proved Reserves. After first booking of reserves, it is possible for an additional development project in the field to have Expectation Reserves but no Proved Reserves, for example when it will be wholly executed on parts of the field that do not fall into the currently defined Proved Area, or when it will install an improved recovery scheme that is not supported by pilot test or local analogy.

Expectation Reserves are subdivided into Proved and Probable Reserves.

Proved Reserves

Proved Reserves are the portion of Expectation Reserves that is reasonably certain to be produced. Proved Reserves volumes are disclosed externally.

Please refer to Appendices 1 and 2 for the full SEC / FASB definition of Proved Reserves and notes on the interpretation of this definition as it is to be applied in Group operations. Note also the conditions that are required with respect to project technical and commercial maturity, section 2.4.3.

In all respects, and particularly when in doubt, the most important concept applicable to Proved Reserves is that of "reasonable certainty". The "reasonable certainty" criterion applies both to the booking of *any* Proved Reserves and to the *volume* of Proved Reserves that is booked. It must be certain, beyond reasonable doubt, that a project for which Proved Reserves are booked will actually be executed. Furthermore it must be certain, beyond reasonable doubt, that the volume booked will actually be produced.

The SEC / FASB rules on Proved Reserves imply that as more data becomes available, upward revision of the estimate is much more likely than negative revision. As fields mature, Proved Reserves are expected to increase towards, and eventually to become equal to, Expectation Reserves (see also Appendix 2.3.1)

Probable Reserves

Probable Reserves are the portion of Expectation Reserves that is not (yet) Proved; alternatively defined as the difference between Expectation and Proved Reserves.

Developed Reserves

Developed Reserves are that part of reserves (whether Proved or Expectation) that is producible through currently existing completions, with installed facilities, using existing operating methods. Facilities requiring minor outstanding activities in ongoing projects can be considered as existing if the outstanding capital investment is minor (< 10%) compared with the total project cost and if budget approval has been obtained. Volumes behind pipe can only be considered Developed if the additional activity (e.g. lower zone abandonment, perforating, stimulating) does not require a full well entry/re-completion and if the cost of this activity (normally Opex) does not exceed 10% of the cost of a new well.

Developed Reserves should in principle be estimated through extrapolation of existing well performance trends. This may be done either through plotting (e.g. rate vs. cumulative production, log oil rate vs. time) or through history matched simulation modelling. If no significant history is available to match, Developed Reserves will be based on pre-development (simulation) model projections, updated for observed well geological and petrophysical data and well rates. In all cases, Developed Reserves should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (the No Further Activity or "NFA" forecast), other than any minor amounts as indicated above.

In general, the NFA forecast for mature assets may include volumes that will require a relatively modest (and clearly economic) level of future Capital Expenditure in order to safeguard existing facilities and equipment (excluding wells, which are discussed separately above). It should be certain, beyond reasonable doubt, that this expenditure will be incurred. Where substantial new investment is (found to be) required in order to safeguard or, in the worst case, replace ageing facilities, consideration should be given to reclassifying the reserves associated with these activities to Undeveloped Reserves.

Please refer to Appendices 1 and 2 for the full FASB / SEC definition of Proved Developed Reserves and notes on the interpretation of this definition as it is to be applied in Group operations.

Undeveloped Reserves

Undeveloped Reserves are that part of reserves (whether Proved or Expectation) that cannot be considered Developed Reserves, as defined above. They require capital investment through future projects (new wells and/or production facilities) in order to be produced. These projects must be technically and commercially mature (Section 2.4.3).

Gas reserves that require the installation of planned or anticipated future compression should be classed as Undeveloped Reserves until the compression equipment has been installed.

Incremental field development projects, which add reserves in their own right, may defer field/platform abandonment and may thereby also increase the reserves producible from existing completions. Such gains should be included in the economic evaluation of the incremental development project and should be included in reserves when the incremental development project concerned reaches technical and commercial maturity (i.e. when its Resource Volumes become classified as reserves).

Future wells or facilities may accelerate reserves that would otherwise be produced by existing assets. The portion of reserves expected to be accelerated by the new investments should be classified as Developed with the existing investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, licence duration), the additional reserves should be classified as Undeveloped until this investment has been made.

The Undeveloped Reserves attributed to a field should be evaluated for each of the specific identified future development activities with which they are associated. The preferred method is through detailed static and dynamic reservoir modelling. Deriving Undeveloped Reserves simply by subtracting Developed Reserves from an assumed total recovery estimate (e.g. from recovery factor correlations) is NOT acceptable.

Please refer to Appendices 1 and 2 for the full FASB / SEC definition of Proved Undeveloped Reserves and notes on the interpretation of this definition as it is to be applied in Group operations.

2.3.4 Guide to the correct allocation of resources to a category

Based on the forgoing, the following diagram summarizes the factors to be taken into account when assigning a Petroleum Resource Volume to its correct category:

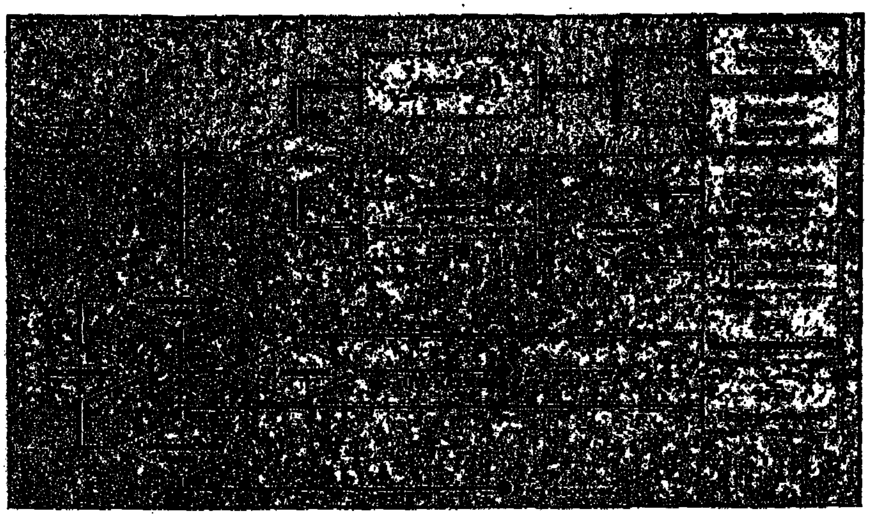

Figure 2: Resource classification guide

A graphical example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.3.1.

2.4 Petroleum Resource Volume Maturation

2.4.1 The maturation process

As a projects matures, the corresponding Resource Volume "cascades" through the classification system (Figure 3). It is recommended that a Petroleum Resource Volume Maturation Plan be maintained for all projects that have material Resource Volumes associated with them, documenting the work activities that are required for a project to pass through each stage of maturation. The project should also have associated with it: a plan of the actions required to mature the resources to the production phase; the associated costs of exploration, development and production; the scheduling of those costs; forecasts of crude oil, natural gas liquids and natural gas sales volumes and, together with associated pricing and fiscal terms, a quantification of the economic performance of the project.

Note that strict criteria apply in relation to technical and commercial maturity before a project can migrate from SFR to Reserves (see 2.4.3 below).

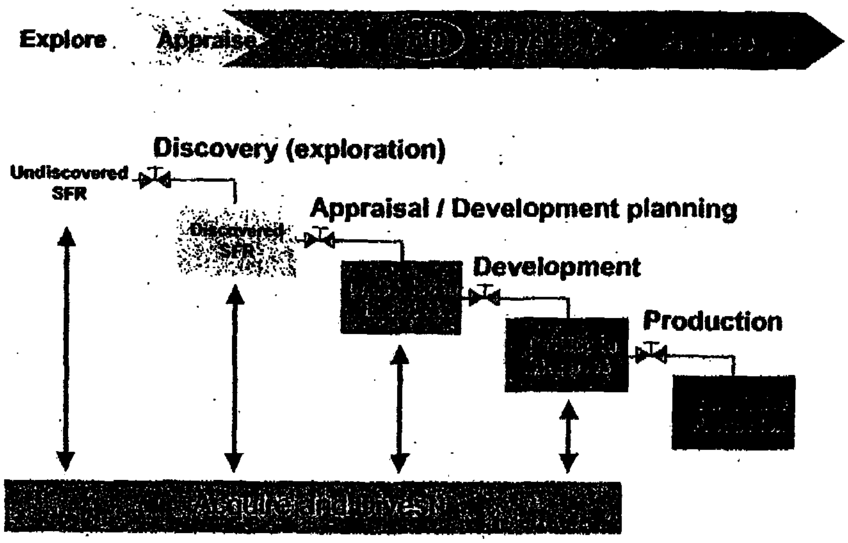

Figure 3: Resource classification flow diagram

2.4.2 Maturation from Undiscovered SFR: Discovery

Discovery occurs when the presence of an accumulation of movable hydrocarbons is proved through drilling and associated data gathering.

The concept of discovery applies to the entire accumulation that has been penetrated by the well, even if the penetration is only partial or the precise vertical and lateral extent of the accumulation has yet to be established or confirmed (through appraisal). All the Resource Volumes that are expected to be contained in the accumulation are deemed to have been discovered. These Resource Volumes mature upon discovery to one or more of the Discovered SFR or Reserves categories, after revisions have been applied to take account of information provided by the discovery well. The estimate of discovered Resource Volumes may have a wide range of uncertainty at this stage, reflecting the uncertainties pertaining to parts of the accumulation that are remote from the discovery well location.

The concept of discovery automatically extends to any areas of the accumulation for which there is a reasonable expectation that hydraulic continuity exists through the hydrocarbon phase with the discovery well location[1]. For "regional accumulations" which lack structural definition of their limits (such as oil shales, regionally pervasive tight gas sands and coal measures), the discovery volume may be limited according to a reasoned view of the area that can be expected to be productive on the evidence obtained from the discovery well, supported by local experience and analogy.

2.4.3 Maturation from SFR to Reserves

For a Resource Volume to pass from SFR to Reserves, the associated development project(s) must reach a minimum level of both **technical and commercial maturity** in order to satisfy the SEC requirement for "reasonable certainty" that the associated Proved Reserves will be produced.

Reserves that already have been booked but which potentially no longer satisfy the criteria for technical and commercial maturity should only be de-booked after thorough (re-)evaluation. This (re-)evaluation must be completed as soon as is reasonably practicable: generally it is not acceptable to retain reserves that cannot be justified. All reserves that are potentially exposed in this manner should be notified to the EP Hydrocarbon Resource Co-ordinator, who maintains an inventory of such volumes.

Project Basis

Reserves are associated either with a project (a development that is planned or in execution) or with an existing producing asset (i.e. a project that has been executed). A project is any planned creation or modification of wells, surface production facilities or production policy, aimed at changing an asset's sales product forecast.

For Reserves to enter into the Proved category, independent review and challenge is required (as a control) to preserve the integrity of external disclosures. For major projects such reviews are routinely executed through the Group's Value Assurance Review (VAR) process, or by locally defined analogous processes in the case of minor projects.

In compliance with the spirit and intent of the SEC rules for Proved Reserves, and also to match reserves additions with external expectations, reserves in principle should not be reported until a project has been sanctioned (Final Investment Decision: FID). This requirement is mandatory for major projects with Proved Reserves exceeding 50 million boe Group share at FID or which require more than US$100 million Group share capital expenditure. In exceptional cases, reserves for major projects may be registered in advance of FID provided that there is a clear public demonstration of the Group's intention to proceed with executing the project, or other mitigating circumstances. Such cases should be raised well in advance of year-end reporting with the SIEP EPS-P.

For intermediate development projects (for which between 10 and 50 million boe Proved Reserves would be booked), concept selection (VAR3) must at least have been completed.

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1 This should not be confused with the much more stringent requirement of "certainty that there is continuity of production" that is required when determining the extent of the "Proved Area" for the attribution of Proved Reserves according to the SEC rules – for example, see Appendix 1.

For small projects (less than 10 million boe Proved Reserves Group share) a documented development plan should suffice, which may be notional if a well established analogy is in place. The quality of such a plan should be a sufficient basis on which to judge the likelihood of project funding.

~~The distinction between major and smaller projects is drawn above because "intermediate" and "small" projects may not be subject to dedicated FID decisions by the EP Executive. However, if any intermediate or small projects are subject to a dedicated FID by the EP Executive it is unlikely that any reserves booking could be made before them.~~

"Major" projects must not be split into several smaller projects in order to avoid the requirement to await FID before booking reserves. Similarly, estimates of Proved Reserves should not be played down for the same reason. The cut-off volumes described above serve as a guide: if there are compelling reasons for accelerating the booking of Proved Reserves for "major" projects ahead of FID, or for delaying the booking of smaller project reserves until FID, these should be discussed with SIEP EPS-P on a case-by-case basis.

It is emphasized that all Proved Reserves require full Group, Region and Asset Holder commitment that the associated projects will indeed be executed. This should be demonstrated by, for example, inclusion of the projects concerned in the current Business Plan, or by a clear demonstration that the projects are certain, beyond reasonable doubt, to be executed.

echnical Maturity

For a project to be technically mature, there must be a documented definition of a technically feasible project that is expected to be implemented with 'reasonable certainty'. The project definition must include: a description of the development concept (including the planned recovery process); specification of the engineering works required (number and type of wells, production facilities and associated support facilities, evacuation infrastructure); drilling/engineering cost estimates; a production forecast (including sensitivities) and economics. There should be no technical issues identified that could prevent the project from proceeding. Please refer also to the general criteria described in "Project Basis" above.

Commercial Maturity

A project is deemed commercially mature, when (1) its profitability meets the Group's investment criteria (as specified in EP's Project Evaluation and Screening Criteria, Reference 12), (2) market availability is assured and (3) funding by the Group is 'reasonably certain' to be provided (i.e. certain, beyond reasonable doubt). There should be no commercial issues identified that could prevent the project from proceeding. Please refer also to the general criteria described in "Project Basis" above.

Assurance of market availability for oil (and/or NGL) means at least the 'reasonably certain' availability of a pipeline to a shipping terminal or other outlet (e.g. a refinery), whilst for existing gas provinces this means that the product is:

1) contracted to sales; or

2) considered reasonably certain of being sold into existing markets, through existing or firmly planned transportation and delivery facilities.

For major gas reserves that rely on the creation of access to market (e.g. those reliant on negotiation of LNG sales contracts), reserves booking should in principle be deferred until certainty exists concerning sales agreements. A Letter of Intent generally will not provide sufficient assurance that a Sale and Purchase Agreement will be concluded. Consequently Proved Reserves cannot be booked on the basis of a Letter of Intent except with the express approval of the EP Executive (such approval should be sought via the EP Hydrocarbon Resource Coordinator). Binding Heads of Agreements are a sufficient basis for the booking of Proved Reserves, provided that such documents are phrased in a way that commits both parties (buyer and seller) to proceed to the conclusion of a Sale and Purchase Agreement. In the event that Heads of Agreement do not provide a binding commitment, Proved Reserves bookings should be deferred until the signature of the Sale and Purchase Agreement.

In all cases, Proved Reserves should only be booked to the extent that they are supported by firm tranches of the sales agreement. Optional tranches – especially those executable at buyer's discretion – should not be used as the basis for booking Proved Reserves unless and until commitments are made for the volumes in question or precedence exists in support of a claim that it is 'reasonably certain' that said volumes will be produced and sold.

Similar conditions apply to planned "spot market" sales of, for example, LNG cargoes. Generally there should be precedence in support of a claim that it is 'reasonably certain' that said volumes will be produced and sold.

The condition of marketability for gas reserves also applies to any associated NGL products. If the gas market is not assured, neither the gas nor the associated NGL volumes can be reported externally.

In some situations, potential buyers of gas or financiers of the associated development projects require evidence of "Proved Reserves" as part of their own assurance processes. Since the assurance of market or finance availability is often a pre-requisite for booking Proved Reserves via the Annual Report to the SEC, marketing and financing requirements may need to be satisfied not with reference to the "SEC" Proved Reserves, but instead to "technical" Proved Reserves, i.e. the Proved Reserves volume that would qualify for disclosure via the SEC assuming that all commercial issues had been resolved.

Projects in Support of Long- erm Commitments

Special consideration may be given to projects that support long-term supply contracts (e.g. LNG sales), for which a commitment has effectively been made to execute the project, but for which the due process of verifying maturity might not yet be fully in place. Such situations can arise when the project will not be executed until far into the future and, consequently, detailed value assurance work has yet to be carried out (VAR3 or higher).

Generally, commitment to the supply contract represents a clear public demonstration of intent to execute the development projects that are necessary in support of it. Also, value assurance work usually will have been undertaken prior to signing the contract or taking FID on any infrastructure in support of it. In such cases, it may be appropriate to register reserves for the projects that are expected to feed the long-term contract. Proved Reserves so registered must adhere to the SEC definition of Proved Reserves (Appendix 1) and must be constrained where necessary by a reasonably conservative estimate of the volumes that will be lifted under the contract (i.e. limited to the duration of existing contracts, unless extension is certain, limited to the Take or Pay volume where applicable, or excluding optional tranches that cannot be considered reasonably certain to be lifted).

3. GROUP SHARE

All Resource Volume estimates reported to EP Planning must be on the basis of Group share. Group share is determined by three factors: (1) the contractual share of produced hydrocarbons, as agreed with the resource holders (usually the host government), (2) the Group share in the assets or the venture that holds the contractual share, and (3) licence duration and other restrictions.

3.1 Contractual Share

Resource Volumes can be distinguished according to three different types of agreement: Equity, PSC and 'New Contracts'. These are described below.

If a company has interests in several licence areas subject to different types of agreement, a separate report must be made with respect to Proved Reserves for each of the contract types.

3.1.1 Equity

Equity resources are the Group share of Resource Volumes in Concessions. Concession agreements lay down the general terms and conditions of operation, define the applicable tax rules, the Group share of Resource Volumes in the Concession and the duration of the production licence. These agreements are generally with the host government, but in the USA they may also be with the private owners of the mineral rights ("lease or fee" conveyance of rights to the operator). Such agreements may also be referred to as "Tax / Royalty" agreements.

3.1.2 PSC Entitlement

PSC Entitlement resources are the Group share of production in acreage governed by a Production Sharing Contract (PSC). The Group entitlement share of production is the Group interest in the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms. The entitlement share is calculated from economic modelling reflecting current estimates of future costs and sales value. The entitlement calculation should be based on the Group's middle PSV of oil or gas (see 3.3.14 below).

To help adhere to the SEC's requirement that Proved Reserves estimates should be much more likely to be revised upwards than downwards in future, the model should be based on a "reasonably certain" production forecast, consistent with the requirements of the SEC Proved Reserves definition (Appendix 1). Similarly, since cost uncertainties can assume a significant role in the overall uncertainty associated with entitlement reserves for mature assets, the PSC entitlement share of Proved Reserves should be calculated using a reasonably conservative estimate of future costs, such that actual costs are more likely than not to be higher than assumed and consequently the Proved Reserves entitlement as estimated today is more likely than not to err on the side of conservatism.

3.1.3 New Contracts

A number of resource-holding countries have introduced innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive, petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind these developments and provide little explicit guidance on reserves disclosure when the risks and rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in external reports in an informative way to be consistent with the spirit of the SEC regulations. The volumes from which economic benefit is derived should be reported, in principle, if all three of the following conditions are met:

1. A physical reservoir of minerals which meet the SEC definition of Proved Reserves must underlie the transaction.

2. The Group must legally own the minerals or be the recipient of an in-substance conveyance of ownership.

   Note: An in-substance conveyance of ownership of (part of the) mineral rights can be deemed to occur if the Group has capital at risk, if the repayment of the capital is dependent on the success of the project and if the Group is, or has been, critically involved in bringing the project to a successful conclusion.

3. The funding must not be a loan with little or no reservoir risk. In other words, the level of risk should be commensurate with the higher levels of risk that are normally associated with oil and gas reserves development, rather than the lower levels of risk that apply typically to loans.

Any new contract that is under consideration must be assessed for the right to disclose reserves on its own merits. This requires early engagement of the EP Hydrocarbon Resource Coordinator, who will be able to provide more specific guidance and engage the Group Reserves Auditor and other experts (including external legal opinion and Group External Auditor opinion) as required.

Asset holders working under such contracts should complete the annual Resource Volume report for the Group interest in these volumes, noting the nature of the interest. Group share of production is calculated from economic modelling of total financial reward in line with contract terms versus total revenues (see also 3.1.2 above). Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost (see 3.3.2).

When participating in a venture which grants neither title nor an entitlement to receive petroleum, and which does not satisfy the three criteria above, no reserves or production volumes should be reported. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes.

3.2 Group Share in EP Legal Entity

If the Group holds only a partial share (i.e. less than a 100% share) in the company or entity that holds the concession or contractual share with the resource owners, this share must be taken into account in the reserves submission.

FASB rules stipulate that when the Group share of such entities exceeds 50%, Proved Reserves are reported on a 100% basis, with the contribution that the minority interest shareholding makes to the total being noted in external disclosures. Prior agreement must be obtained from Group Finance before such reporting is considered. When the Group share of such entities is 50% or less, reserves are reported on the basis of the share holding.

3.3 Licence duration and other restrictions

3.3.1 Licence or Contract Extensions

For internal reporting, Group share of Expectation Reserves and SFR are recorded for the economic producing life of the asset, regardless of the expiry date of current licences. Current licence terms should be assumed to apply to any licence extension or renewal unless it is known or expected that different terms would apply. In addition, Resource Volumes are also recorded as limited to the current licence period (including any extension or renewals that are certain to be granted, see below) for Expectation Developed Reserves, Expectation Reserves and SFR.

For external reporting, Group share of Proved Reserves and Proved Developed Reserves is limited to future production within the existing licence or contract period, including any extensions or renewals that are covered by documented agreement, by legally enforceable rights or where precedence supports the view that extension or renewal is granted "as a matter of course" by the applicable authorities. Estimates of "post-licence" Proved Reserves are also collected, so that the reward associated with licence extension can be judged, but these volumes cannot be included in external disclosures.

3.3.2 Royalty

Outside the USA, royalty is a payment made to the host government for the production of mineral resources. It is usually calculated as a percentage of revenues (payable in cash) or production (payable in kind).

Where in practice royalty obligations are met in kind (i.e. by delivering oil instead of cash), the Group share of production and reserves should be reported excluding these volumes.

Where royalty is payable in cash or is in principle payable in kind but the government has formally elected to receive, or customarily receives, payment in cash, Group share of production and reserves should be reported including these equivalent royalty volumes.

Within the USA, royalties are payable to the owner of the mineral rights, who can either be a private or a public entity (e.g. State government). In line with SEC regulations, these are always excluded from Group reserves whether paid in cash or in kind, for US properties.

3.3.3 Overriding Royalty

In the USA, there are often Overriding Royalties payable to the owner of mineral rights or third parties. These shares of reserves are excluded from Group reserves. Third party Overriding Royalties payable to Shell are included in Group reserves.

3.3.4 Own Use and Losses

Group share Resource Volumes must exclude any volumes consumed as "own use" (fuel for production facilities, compressors etc) or lost (flared or vented) in the upstream operations prior to transfer of the product to the buyer (Third Party' or 'Downstream'). This is consistent with the definitions applied for e.g. Gas Production available for Sales from own reserves (GPafS), as applied in financial reporting (Ref. 10).

3.3.5 Fees in kind

Third Parties may in some cases pay Fees in Kind or Tariff in Kind for the use of infrastructure (e.g. pipeline tariff, processing fee). Such volumes received by the company (to the extent that they originate from non-Group owned resources) do not constitute a Group share in resources and should be excluded from reported volumes. Condensate volumes recovered from a pipeline system related to transportation of Third Party gas volumes and sold by the company are equivalent to Fees in Kind received. All Fees in Kind received should be included as a purchased volume in the company accounts.

Where a company pays Fees in Kind (from its own fields/resources) to a Third Party, these do constitute a Group share in resources and should be included in the reported volumes. Annual volumes produced and used as Fees in Kind should be included in sales volumes, with associated revenues (at an agreed or fair market value) equivalent to booking of the incurred operating cost.

3.3.6 Under-lift and Over-lift

Group share should allow for any historic under-lift or over-lift by partners or government. A Group historic over-lift should be reflected as an equivalent reduction of Group reserves, a Group historic under-lift as an equivalent increase of Group reserves.

Group share should reflect the effect of swap deals, for example in gas fields in which early production capacity in one field is traded against later production repayment by the other. In principle, reserves booked for each field should reflect the volumes actually produced (and sold) from the field in question.

Treatment of take-or-pay volumes should be aligned with financial treatment of the cash received and booking of production volumes. This generally means that volumes paid for but not yet taken (produced) should be included in reserves.

It is essential that the treatment of reserves and production in the above cases are consistent with the corresponding treatment of Group income in financial reporting, see also 3.3.13.

3.3.7 Open Acreage

Group share of Resource Volumes is non-existent in open acreage and acreage for possible future acquisition or farm-in.

3.3.8 Committed Gas Reserves

This is the total volume of Expectation Gas Reserves Within Licence that has been committed for sale under long and short-term contractual agreements. In countries with a mature or deregulated gas market, all gas reserves which have a near certainty of market take-up can be classified as Committed.

3.3.9 Committable Gas Reserves

This is the total volume of expectation gas reserves that has not been sold, but which could be sold under contractual agreements yet to be negotiated. The sum of committed and committable gas reserves is equal to the Expectation Gas Reserves Within Licence.

3.3.10 Gas Re-injection

Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservation, Underground Gas Storage (UGS, including cushion gas), or other reasons, **without transfer of ownership**, remain part of a company's resource base and should be **included** in the Group Resource Volume estimates. These gas volumes should be classified and reported as reserves or SFR, depending on the recovery anticipated through future developments (also taking into account anticipated re-saturation losses).

Gas volumes re-injected in a UGS project on behalf of a **Third Party** (either following transfer of ownership by the company to this party, or following production by the third party itself) do not constitute a Group share in resources and should be **excluded** from reported volumes.

3.3.11 Oil Sands

Petroleum volumes (heavy oil, bitumen, syncrude, gas, liquids, etc.) recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a "manufacturing" process must be reported **separately** from the conventional resource base. This includes conventional reservoirs where recovery occurs through a mining operation. However, conventional Reserves or SFR can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e. has not been "manufactured"" *in situ* by alteration from natural state) through the use of conventional methods (wells). Examples of this are coal bed methane produced from wells or heavy oil produced from wells using conventional thermal recovery methods.

3.3.12 Aggregated production forecast

The aggregated production forecast of an entity must be consistent with its reported reserves. This also holds for the 'proved forecast', as defined by the aggregated 'reasonably certain' amount of petroleum forecast to be produced by the appropriate development/production scenario, duly respecting license duration and overall constraints (e.g. quota).

The total Proved Reserves disclosed by an Asset Holder should be underpinned by a corresponding production forecast that at no point in time exceeds the Asset Holder's aggregated Business Plan forecast. In general it is expected that the production forecast for Proved Reserves will start at the same level as the Business Plan forecast and that it will gradually fall below it over time, reflecting the decreasing level of certainty that is normally associated with longer term elements of the Business Plan. The Proved production forecast should contain only the current Proved Reserves and the corresponding projects. In principle project scheduling should be the same as that of the Business Plan forecast, or somewhat accelerated if this can be justified. Refer also to Appendix A2.3.3.

3.3.13 Consistency with financial reporting

Proved Reserves and production must be reported consistently with procedures adopted by the Asset Holder's finance department, guided ultimately with reference to the Group Financial Information Manual (GFIM, Ref. 10). Close co-operation is therefore required between the finance and technical functions to ensure that alignment exists. Areas for attention include, but are not limited to, the reporting of: Total Oil Sales; Total Net Gas Production Available for Sale; quantities used in the calculation of depreciation through the Unit Of Production method; gas volumes paid for but not lifted; volumes reported in relation to Group consolidated companies; etc.

3.3.14 Oil and Gas Price

Resource Volumes should be evaluated at the Group Mid PSV of oil and gas price: that is, the economic limit for production operations in which Resource Volumes are reported using the equity method (see 3.1.1 above) should be established based on the Mid PSV. Similarly, when estimating Resource Volumes using the entitlement method (PSCs and "novel" contracts – see 3.1.2 and 3.1.3 above), the Mid PSV should be used as the basis of the calculation.

This approach could be deemed contrary to the letter of the SEC rules for Proved Reserves, which imply that the prices extant on the date of the estimate (31st December) should be used. The Group retains the Mid PSV as the basis for reporting since (1) changes in product price have either neutral or opposing effects on the reserves estimates for the equity and entitlement methods, so that overall the Group's Proved Reserves are relatively insensitive to changes in product price; (2) the adoption of year-end pricing could lead to excessive annual revisions to the Proved Reserves estimates for individual assets, and; (3) it is generally not feasible to await observation of the year-end price before completing, auditing and discussing with other stakeholders the estimate of Proved Reserves.

The Group's disclosure of the Standardized Measure of Discounted Cash Flows is calculated at the actual year-end price.

4. ASSESSMENT, REPORTING, RESPONSIBILITIES AND AUDITS

Resource classification and reporting is designed to support the Group's decision-making process with respect to resource allocation and portfolio management in pursuit of profitable business growth and reserves replacement objectives. Efficient systems to monitor the annual changes in the various resource categories are therefore essential.

An asset holder's internal resource assessment and reporting systems should:

a) Record the maturation plans for all Scope For Recovery opportunities (projects),

b) Monitor performance in maturing volumes relative to target,

c) Provide for systematic controls to assure the integrity of volumes that are reported,

d) Provide for regular review of ultimate recovery targets for existing fields in pursuit of constant improvement,

e) Record Key Performance Indicators (KPIs) to measure performance, e.g. reserves replacement ratio, Scope For Recovery maturation ratio, time between discovery and first production.

4.1 Shareholder Requirements

EP Planning will communicate each year a timetable and details of data submission requirements for both internal and external reporting.

Volumes will be reported based on the classification system described in this report. Additional information is reported for the calculation of the Standardized Measure, external disclosure of which is required by the US Financial Accounting Standards Board (FASB).

4.2 Methods and Systems

Asset holders are responsible for selecting the methods and systems that are technically the most appropriate for quantifying the Resource Volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves.

4.3 Responsibilities and Audit Requirements

4.3.1 EP Planning Responsibilities

EP Planning is responsible for compilation of the Group statistics of Resource Volumes, the analysis thereof and the communication to other functions. EP Planning also maintains the Petroleum Resource Volume guidelines.

4.3.2 Reserves Auditor Responsibilities

The Group Reserves Auditor carries out regular detailed reserves audits in asset holders to verify compliance with the Group's guidelines. The Terms of Reference for such audits are included in Appendix 3. In addition the Group External Auditors verify the Proved Reserves data for external disclosure.

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4.3.3 Region and Asset Holder Responsibilities

Definition of internal reporting requirements, tasks and responsibilities should be as per the Region's (or Asset Holder's) Management System (Ref. 5). Technical and Financial functions must co-ordinate and reconcile their figures (particularly production volumes) prior to submission.

All levels in a Regional organization, including asset managers and the reservoir engineer preparing the individual field reserves estimates, must be aware of the importance of externally reported reserves (Proved, Proved Developed) and their impact on financial indicators.

Region and asset holder management is responsible for ensuring that the guidelines are implemented in such a way as to best represent to shareholders and potential investors the true value of the asset, subject to the rules and regulations of the SEC and FASB, as stated and interpreted herein (Appendices 1 and 2).

4.3.4 Reserves Operated by Others

Where Shell is not the operator, the Group company that holds the interest/share in the venture is responsible for the preparation of the reserves submission. In this case the Group company involved is responsible for ensuring that reporting is compliant with Group guidelines.

This may involve reclassification of volumes between Reserves and SFR categories where the operator's criteria differ from Group criteria concerning the evaluation of Proved Reserves.

4.3.5 Audit Trail

Audit trails are essential in the Resource Volume reporting process. They are indispensable tools for the Group Reserves Auditor to assess the quality of the Proved Reserves estimates and when handing over Resource Volume estimates between field reservoir engineers and reserves co-ordinators and their successors. They should support and document the reported figures and ensure that the Region and Asset Holder management understand and "own" the reported volumes.

For all Resource Volumes an audit trail must be available of the assumptions made and processes followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, EP Planning should be advised at the earliest opportunity.

Guidelines on how to prepare a good audit trail, with suggested formats for tables etc. can be found on the Shell Wide Web (Ref. 11).

4.3.6 Data Management

The reporting of Resource Volume data to EP Planning is achieved using a standard Excel template workbook (the "Resource Volume Workbook"). This is described in a separate document (Ref. 2).

Each asset holder must adopt a system for storing Resource Volume data that both delivers data in the required format for the Resource Volume Workbook and meets the needs of the asset holder for planning and monitoring performance in petroleum resource maturation. Typically the latter requirement means that data must be stored at a finer level of resolution than is required for the Resource Volume Workbook. The detail and sophistication of the data storage and management system is dictated largely by the nature and complexity of the portfolio of assets in question.

Whatever system is used, it must store data in such a way that changes to Resource Volumes can be tracked over time. Systems must provide for the aggregation and reporting of year-end Resource Volumes in each classification system category. They must also provide for the aggregation of changes in Resources Volumes that occur in each year, enabling changes to be further subdivided by each of the "reasons for change" that are prescribed in the Resource Volume Workbook (Ref. 2).

Asset holders are advised to record all Resource Volumes in such a way that they can be aggregated and expressed on a per-field basis (in the event that a field may be the subject of several different projects) or a per-project basis (in the event that a single project addresses several different fields) when required.

At present there is no single Group-supported system for the storage of Resource Volume data. Each asset holder typically makes use of a system that has been tailored to the complexity of its portfolio of assets. These systems include RISRES (for the more complex portfolios), FASTRACK, commercially available software and Excel spreadsheets. All such systems must be accompanied by a documented audit trail that summarizes the source and location of the relevant information.

Consideration is currently being given to introducing a Group-standard system, with links to the systems used for business planning and capital allocation.

REFERENCES

1. EP 2002-1100, "*Petroleum resource volume guidelines, resource classification and value realisation*", April 2002.
2. EP 2002-1101, "*Petroleum resource volumes submission requirements for internal and external reporting*", October 2002 (EP 2003-1101 in preparation for issue in October 2003).
3. EP 2003-1102, "*Guide for the Administration of Proved Reserves and Production for External Disclosure*", July 2003
4. EP 88-1145 Part 2, "*Methods and procedures for resource volume estimation*", SIPM, April 1988.
5. EP92-0945 "*Business process management guideline*", SIPM, EPO/72, June 1992
6. "*Petroleum Reserves Definitions*", Society of Petroleum Engineers and World Petroleum Congresses, http://www.spe.org/spe/jsp/basic/0,2396,1104_12169_0,00.html

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7. Handbook of SEC Accounting and Disclosure
8. "*Issues in the Extractive Industries*", United States Securities and Exchange Commission (SEC): http://www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm#P279_57537
9. Statements of Financial Accounting Standards (FAS) numbers 19, 25 and 69, Financial Accounting Standards Board (FASB).
10. Group Financial Information Manual – GFIM
11. SIEP EPS Planning and Economics website: http://sww.siep.shell.com/epb/epplan/index.htm
12. "*Project Evaluation and Screening Criteria*", August 2003, SIEP.
13. EP 2000–9119, "*Estimating pay probability downdip from well control using seismic amplitudes*", A.K. Jackson, S.J. Saleh, P.J. Doe, STEP (Houston)

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    EP 2002-3040, "*Downdip Amplitude Evaluation Process: A Step-by-Step Guide*", A.K. Jackson, SIEP (Houston),
14. "*Understanding US SEC guidelines minimizes reserves reporting problems*", T.L.Gardner, D.R.Harrell, Oil&Gas Journal, Sept 24, 2001.

APPENDIX 1 PROVED RESERVES – DEFINITION

United States Securities and Exchange Commission (SEC), Rule 4-10(a) of Regulation S-X, produced pursuant to the United States Securities Exchange Act of 1934:

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.

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.

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.

Shell's interpretation of the SEC definitions, supplemented by guidance published by SEC staff, is as follows:

	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
1	**Reasonable Certainty** 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 ...	Future revisions should be more likely to be upward than downward. A conservative approach is required until data is supported by field evidence.	Future revisions should be more likely to be upward than downward. Reserves estimates for new and recently developed fields should be based on a Low case (conservative) projection of future production and should be consistent with 'Proved Area' volumetrics.
		Performance-based projections may be the median, not necessarily the low estimate.	Reserves estimates for mature fields should be based on 'best estimate' performance extrapolations and projections. Proved reserves should grow towards Expectation reserves with increasing field maturity.
2	**Existing Conditions, Prices and Costs** [Proved reserves should be estimated] ... 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.	Existing economic and operating conditions may include future changes in these conditions. Such future changes must be known and determinable, must have a reasonable certainty of occurring and must be included in the economic feasibility. The latter must also include abandonment.	Existing economic and operating conditions may include identified future changes in these conditions (e.g. new developments), provided their costs are fully included in the project economics. Projects must be economically viable (in the Expectation case). Abandonment costs should be included in economics.
		Prices and costs should be as of the date the estimate is made, i.e. at the last day of the year.	Prices should be as per Group Mid Project Screening Value (PSV) of oil and / or gas price, this reflecting the Group's long-term estimate of product prices based on currently existing conditions.
3	**Producibility** Reservoirs are considered proved if economic producibility is supported by either actual production or [a] conclusive formation test. In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate [that] the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. (Topic 12 of Accounting Series Release No. 257 of the Staff Accounting Bulletins).	Producibility must be demonstrated through a full formation test or through production at economic rates. Cannot be a wireline formation test. Proved reserves in unproduced reservoirs can be claimed only if an analogy can be demonstrated with other produced reservoirs in the same field. This analogy requires the 'overwhelming' support of log <u>and</u> core data (which should be favourable to the unproduced reservoir). Note: This allowed analogy seems much more strict (log <u>and</u> core data; in same field) than that allowed for Improved Recovery.	Producibility is demonstrated either through production or a production test, through a wireline test, or through log and/or core data that give positive demonstration of analogy with other produced reservoirs in the area (NB – not necessarily in the same field). A fluid sample must be available.

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	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
4	**Proved Area – Fluid Levels** The area of a reservoir considered proved includes that portion (...) defined by gas-oil and/or oil-water contacts, if any. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.	Reserves down to a known fluid contact or the Lowest Known Hydrocarbons (LKH) may be considered as proved. In the absence of a fluid contact, no reservoir volume below the LKH shall be considered as proved. Note: Recent statements by the SEC imply that no proved reserves can be attributed below the lowest logged hydrocarbon under any circumstances until performance data is available that clearly demonstrates their presence. The Shell Group is currently seeking clarification of this matter from the SEC.	Proved reserves shall fulfil 'Proved Area' conditions (see definition below). Water levels (and volumes below LKH) may be considered proved based on indirect evidence obtained from pressure measurements made in the reservoir concerned. Volumes below LKH can also be considered proved if good quality seismic amplitudes can be considered proof of hydrocarbons and if these are continuous over the area (Ref. 13).
		Proved oil reserves can be carried above Highest Known Oil only if there is compelling evidence of the oil being undersaturated (Ref. 14).	Proved oil reserves can be carried above Highest Known Oil if there is convincing evidence of the oil being undersaturated.
5	**Proved Area – Lateral Extent** The area of a reservoir considered proved includes that portion delineated by drilling (..), and 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 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.	The Proved Area should consist of one 'legal' (USA) or technically justified (non-USA) drainage area around the wellbore, plus up to eight surrounding ('offset') legal or technical drainage areas. Areas outside these 'offset' locations can only be considered proved if continuity of production is certain. Continuity of production means more than just continuity of the producing formation. Hydraulic continuity of the hydrocarbon fluid and producibility of the reservoir must be demonstrated with certainty. This requires conclusive evidence of communication from production or (interference) pressure measurements. Seismic data alone is not seen as a sufficient condition to prove communication over areas outside the eight 'offset' drainage areas.	Proved Reserves shall fulfil 'Proved Area' conditions. The 'Proved Area' is defined as an area of the reservoir with at least one well penetration and with confirmed producibility either in the reservoir itself or in an analogous reservoir. The Proved Area is delineated by water levels proved either by logs/cores or by pressure interpolations in the reservoir. Continuous good quality seismic amplitudes, giving positive indication of hydrocarbons may further delineate the area (conditions in Ref. 13). The area should not extend beyond potentially sealing barriers or faults. Areas extending beyond nine well drainage areas can be accepted as a basis for proved reserves if there is a demonstrated analogy with a proved reservoir (of same or poorer properties) in the area, or (preferably) through observed pressure or fluid responses in the reservoirs.
		The above conditions can be waived only by conclusive reservoir production evidence or performance.	The above conditions can be waived by conclusive reservoir production evidence or performance.

	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
6	**Proved Developed 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.	Proved developed reserves can also be booked if only minor expenditure is outstanding before production can be started (e.g. sales connection, re-completion, additional perforation, bore hole stimulation).	Proved developed reserves require existing facilities and completions, with existing operating methods. If outstanding activities in ongoing projects are only minor (<10% of project Capex), the project can be booked as developed. Similarly, reserves requiring only minor well activities (<10% of cost of new well) may be booked as developed. Proved developed reserves should be derived from production trend extrapolations or through No Further Activity (NFA) forecasts from simulation models. These models must be properly history matched when production history is available.
7	**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.	Proved reserves must be booked as undeveloped if major expenditure is required to produce the volumes.	Proved undeveloped reserves are reserves that require significant additional development capital expenditure to enable production (see above). Reservoir simulation is the preferred tool for determining undeveloped reserves. Undeveloped reserves must be based on specifically identified future activities (new wells or facilities).
8	**Improved Recovery** Reserves which can be produced economically through applications 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. 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.	To carry Improved Recovery proved reserves, the improved recovery method must either: - Be verified by routine commercial use in the area, or - Have a technically and commercially successful pilot test or an installed program in that specific rock volume in the field, or - Have a successful pilot test in an analogous reservoir in the same geologic formation in the immediate area. An analogous reservoir is one having the same or poorer reservoir properties (porosity, permeability, thickness, hydrocarbon saturations, continuity). Note: This allowed analogy is much more lenient than that allowed for producibility.	Improved Recovery proved reserves in frontier areas can be booked without a pilot if the latter is not justified and if other information (core and fluid studies, analogue field experience) provides the necessary assurance (Value of Information approach). This implies that the project must be technically and commercially mature and project financing must be reasonably certain without the pilot. FID must have been taken for major projects.
	Under no circumstances should estimates of 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.	Improved Recovery proved developed reserves can be claimed only for those wells that have shown production increases associated with the improved recovery technique.	Improved Recovery proved developed reserves should be based on performance extrapolations as soon as feasible.

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	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
9	**Reasonable certainty of development** Estimates of proved reserves do not include the following: - 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;	Proved reserves require a serious commitment to pursue the project, e.g. AFE, FID, MOU, signed contracts, firm plans and timetables. This implies economic viability. Project financing must be reasonably certain. An inordinately long delay in the schedule of development may introduce doubt, sufficient to preclude the attribution of proved reserves. Proved reserves must have a reasonable certainty that a market exists, e.g. existing or firmly planned evacuation infrastructure, sales contracts or commitments. Proved reserves require continuance of permits, concessions and commerciality agreements to pursue the project. If the regulatory body has the right to end the agreement upon expiry, automatic renewal can only be assumed if there is a long and clear track record of renewals and if there is no reason to expect that this renewal may not occur.	Projects must be Technically and Commercially Mature and funding under the Group Capital Allocation scheme must be likely. Technical Maturity implies that there are no potential show stoppers. Commercial maturity implies that evacuation routes will be available and that a market is reasonably certain for gas volumes (e.g. through binding Heads of Agreement or and actual Sales Agreement). FID must have been taken for major projects. Smaller projects should have passed VAR3 or similar peer reviews. Proved volumes must be produced within existing production licences or their extension if there is provision for the latter in the licence permit.
10	**Unproved reserves and non-reserves** Estimates of proved reserves do not include the following: - oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; - crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; - crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.	Tar sands, Oil sands, Oil shales etc must be booked as mining reserves, not petroleum reserves, if recovery is not through the drilling of wells.	Heavy oil, bitumen, syncrude, gas, liquids, etc. recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a "manufacturing" process must be reported separately from the conventional resource base. However, reserves can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e., has not been "manufactured" in situ by alteration from natural state) through the use of conventional methods (wells). An example would be coal bed methane. Volumes in undrilled prospects or unappraised fields are carried as SFR.

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	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
11	**Probabilistic methods of reserve estimating**	Probabilistic methods are recognised to have become more useful. The issuing of confidence criteria (e.g. 90%) is at this stage too premature. Past and current practices utilize a median or best estimate, which may imply that future revisions are not more likely to be positive than negative. This inconsistency should be resolved. Limiting criteria, e.g. LKH, shall still be honored.	Deterministic Low case scenario modelling (based on 'Proved Area' volumetrics in immature fields) is the preferred method for estimating proved reserves. Probabilistic methods are recommended mainly for calculating volumes in exploration prospects and unappraised discoveries. If probabilistic volumetric calculations are used for estimating proved reserves they must conform to 'Proved Area' conditions.
		A straightforward reconciliation is required for financial reporting purposes if probabilistic addition is used.	Probabilistic addition should only be used at levels below those used for financial asset accounting.
12	**Standardized Measure** Standardized measure of discounted future cash flows relating to oil and gas properties must comply with para 30 of FAS 69*.	All elements, including income tax, must be discounted at the standard rate of 10%. "Short cut" as per SAB topic12:D:1-Qu.2 may not be used.	Standardized Measure submissions are based on end-year prices and full-year average operating costs. Capex costs are as per date of estimate. The prescribed discount rate of 10% is used.
	Future cash inflows [should] be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. (*Statement of Financial Accounting Standards 69, paragraph 30.a.)	End-year prices mean physical prices on the last day of the year. The same requirement applies to (future) costs.	
13	**Production Sharing Agreements**	Proved reserves must be based on the "economic interest method" (future cost and profit oil revenue divided by year-end oil price) and not the "working interest method" (working interest in contractor venture, minus royalty), as the sum of all entitlements must not exceed 100%. Reserves volumes determined by various owners should add up to 100% of field volumes. Producer must have the right to extract the hydrocarbons and must be exposed to exploration / development risk.	Reserves are based on cost and profit oil revenue divided by a reference oil price as per Group PSV screening values. PSC entitlement share should be calculated using a reasonably conservative estimate of future costs. For PSCs and other novel contracts: The company should have provided / contributed technical upstream expertise to the project and it should have funded development capital that is subject to upstream risk.

APPENDIX 2 RESOURCE VOLUME ESTIMATION

A2.1 Quantification methods

Resource Volume estimates are inherently subject to uncertainty because they are based on sparse data (from seismic and drilling) and interpretations that contain sometimes significant margins of error. In-depth understanding is necessary to enable 'realistic' reporting of Proved Reserves. The most important methods to quantify and assess the range of uncertainty in Resource Volume estimates are:

- The Probabilistic method (p85, Mean, p15)
- The Deterministic method:
  - Multi-scenario
  - SEC / SPE (Proved, Probable, Possible)

The SEC Proved Reserves definition is strictly deterministic and all Proved Reserves disclosed externally by Shell should adhere to the SEC definition. Group practice in this respect is summarized in section A2.2.

A2.1.1 The probabilistic method

The probabilistic method is good for assessing the uncertainties of exploration prospects, partially appraised discoveries and single development concepts in general. For (major) fields that are at the "concept selection" stage the multi-scenario method is preferred, as described below.

The probabilistic method has been in use by the Group since the 1970s. Whilst the Group was initially alone in the industry in applying it, the method has gradually gained wider acceptance, e.g. by the SPE (Ref. 6).

The method consists of assigning probability density functions (PDFs) to each of the parameters that define a Resource Volume estimate (e.g. gross bulk volume, porosity, hydrocarbon fill and saturation, hydrocarbon volume factor, recovery factor). The PDFs are then combined either mathematically ('moment' method, see Appendix 7 of Ref. 4) or, more commonly, through Monte Carlo simulation. The Monte Carlo method selects a value at random from each of the parameter PDFs, combines them to yield a Resource Volume estimate, and repeats this process many times over to yield a PDF for the Resource Volume itself. Software tools that use Monte Carlo simulation include @RISK, Crystal Ball and FASTRACK.

The PDF of the Resource Volume may be integrated to yield a cumulative probability function (CPF), which defines the probability that the Resource Volume exceeds each value in the range of possible outcomes. The Resource Volumes associated with the 85% and 15% confidence levels are referred to as the Low and High estimates (or p85 and p15). The probability-weighted average value of the entire distribution is referred to as the Expectation value. The reason for the original selection of the 85% and 15% intervals by the Group was that they aligned most closely with the previously used distributions of three equi-probable values. More recently, the SPE and some operators and authorities have tended to favour 90% and 10% intervals (p90 and p10 respectively).

A2.1.2 The deterministic multi-scenario method

This method is applied in principle before technical/commercial maturity is achieved and its application is predominantly in support of development concept selection. The method involves modelling through a full set of static (geological) and dynamic (reservoir simulation) models, all of which are internally consistent and honour the available data. The static model is generally run for a range of possible subsurface realisations, yielding a range of hydrocarbon-in-place volumes.

A representative selection of alternative geological model realisations is converted ('upscaled') into a discrete set of reservoir simulation models, which are then run each for a range of alternative development scenarios (e.g. different well numbers or positions). The alternative development scenarios are not necessarily identical for each geological realisation.

An important characteristic of the multi-scenario method is that it is project- or activity-based, i.e. the recoverable volumes are linked to a specific development plan or plans, with identified (or identifiable) costs, production forecasts and economics. These aspects make this approach well suited to supporting development concept selection.

In its simplest form, the method may yield Low, Middle and High estimates of Resource Volumes. However, it is increasingly common to apply the method to far more possible realizations, yielding, in effect, a PDF for the Resource Volume, with each discrete point on the PDF being defined by a unique deterministic scenario. Although it may be tempting to equate the p85 of the corresponding CPF to "Proved Reserves", it is important to bear in mind that the externally disclosed Proved Reserves must still conform to the Group guidelines (i.e. the SEC rules) on the definition of Proved Reserves (see A2.1.3 and A2.2 below).

A2.1.3 The SEC / SPE deterministic methods

The deterministic method has been the method most frequently used by the industry at large. It derives from the original definitions of 'Proved Reserves' as issued by the US Financial Accounting Standards Board (FASB) and by the US Securities and Exchange Commission (SEC) (Refs. 7, 8 & 9). These definitions describe the mandatory conditions for reserves that are reported annually through company reports and public submissions to the SEC.

Proved Reserves are defined by the SEC as "...the estimated quantities of hydrocarbons which geological and engineering data demonstrate with reasonable certainty to be recoverable...". 'Reasonable certainty' is implied to mean that future reserves revisions are 'much more likely' to be positive than negative. Pivotal in the definition of Proved Reserves is the notion of a **'Proved Area'** of reservoir rock, outside of which no Proved Reserves can be attributed. Similarly, only recovery from techniques that have been proved effective can be included. Please refer to Appendix 1 and to Reference 8 for further information on the constraints applicable to the definition of the Proved Area and Proved Reserves estimates, but take note also of the current Shell guidelines on interpretation, also included in Appendix 1 and summarized in A2.2 below.

The practice in the industry at large has been that Proved Reserves estimates are generally 'best estimates', with the Proved Area constraint being the only conservative element that is strictly adhered to. An important consequence of this in relation to the Group's histroical practice is that Proved Reserves as calculated by the deterministic method tended to be lower than probabilistic p85 estimate for new discoveries and undeveloped fields. Similarly, they were generally higher for mature, fully appraised fields.

The SPE (Ref. 6) extended the definition of "Reserves" to include Probable and Possible Reserves. Whilst the latter two are commonly referred to by the industry at large, they do not qualify for disclosure according to the SEC rules. The SPE definition of Proved Reserves is somewhat more relaxed than the SEC's, for example by allowing probabilistic techniques (with Proved Reserves equating to the p90 confidence level). This theme is extended through the Probable and Possible definitions, for which some of the key features are:

Probable reserves:

- 'More likely than not to be recoverable'; p50 if based on probabilistics,
- Probably productive from logs/cores,
- Likely volumes outside the 'Proved Area', e.g. updip behind interpreted faults,
- Volumes probably recoverable through unproved techniques (no successful pilot yet)

Possible reserves:

- 'Less likely than Probable', p10 if based on probabilistics,
- Hydrocarbon bearing from logs/cores, but possibly not productive,
- Possible volumes outside the Proved Area, e.g. downdip behind interpreted faults,
- Volumes recoverable through unproved techniques, with success in 'reasonable doubt'.

Industry practice tends to be that Probable Reserves sometimes contain not only volumes associated with areas in the field outside the volumetric confines of the 'Proved Area', but also volumes associated with projects that have not been fully matured or approved yet.

The sum of Proved and Probable reserves is sometimes regarded as equivalent to the Mean or Middle estimates from probabilistic or multi-scenario methods. Similarly, the sum of Proved, Probable and Possible has been equated to p10 or High reserves. However, the definition for Possible Reserves clearly indicates that many of these volumes (and even some Probable Reserves volumes) would be classified as SFR in the Shell system.

A2.2 Shell Group Practice

Group practice has long been based on the probabilistic method for estimating Expectation Resource Volume estimates (for internal reporting). Proved Reserves (for external reporting) were for many years set equal to the probabilistic p85 estimates, which tended to change little as fields matured. This approach was found to lead to under-reporting of reserves in mature fields compared with major competitors and consequently it was replaced by a deterministic approach in 1998. In following the guidelines of the US Financial Accounting Standards Board (FASB) and the US Securities and Exchange Commission more strictly, the Group's reporting practice is now more in line with its major competitors (in particular with respect to mature fields).

First "booking" requires auditable evidence of technical and commercial maturity, to the extent that the project(s) are reasonably certain to attract corporate funding.

The preferred approach to development concept selection as it leads up to field development planning is based on the multi-scenario method. Reserves assessment is, however, to be based on the development concept that is actually selected for execution. Proved Reserves estimates should in principle be consistent with volumetrics in the 'Proved Area', which is defined by (see also Appendix 1):

- Demonstrated producibility through a production test, or log/core data in a tested area,
- Delineated by GOC, OWC, GWC as seen/interpreted from pressures in the reservoir or by good quality seismic amplitude data (Ref. 13); if neither is available, by LKH,
- In the absence of 'legal' well spacings, laterally defined by well control and surrounding areas with continuous and good quality seismic amplitudes (Ref. 13), but not beyond potentially sealing barriers or faults. Evidence from well drainage limit tests may be used.
- Extended by production performance data, if conclusive,
- Improved recovery volumes supported by a pilot or a robust analogy.

Underpinning this approach is the concept that the drilling and completion of development wells will generally expand the 'Proved Area' until it covers much, if not all, of the field. Even if still incomplete at first (i.e. after the first phase of development drilling), this coverage will increase to full coverage with growing field maturity and performance. In line with industry practice, Proved Reserves should be based on 'best' or Expectation estimates of 'Proved Area' volumetrics (in-place volumes).

Apart from the volumetric uncertainty, there is the uncertainty regarding reservoir performance (determined by sand development, reservoir continuity, injectant sweep efficiency, aquifer activity, etc.). The latter uncertainty will be reduced as production progresses. Hence, a cautious, 'reasonably certain' approach should be followed for performance predictions in new fields (i.e. the classic Shell approach adopting the Low natural outcome of the FDP as Proved Reserves remains valid). For mature fields the Proved Reserves are expected to grow towards Expectation as field life progresses and the uncertainty range narrows. In some mature fields with well established production trends Proved Developed Reserves may become equal to Expectation estimate.

The resulting assumptions to be used for estimating Proved and Expectation Reserves is given in Fig. A2.1 (below). To the extent that reserves (particularly Proved Reserves) are still based on probabilistic estimates, consistency with these assumptions is required.

Expectation Developed and Undeveloped Reserves (internal reporting):	**All fields**	**Mean probabilistic or Middle case outcome of the development concept selected and approved for execution, based on Expectation volumetrics. (Proved+Probable if appropriate and if no Mean or Middle available)**
Proved Developed Reserves (external reporting):	New, recently developed fields:	'Reasonably certain' (Low case) outcome of the development concept selected and approved for execution based on Expectation 'Proved Area' volumetrics.
	Mature fields:	Best estimate performance projection, based on Expectation "Proved Area" volumetrics. Err on the side of conservatism when in doubt. The Proved Developed Reserves estimate should approach (and may become equal to) the Expectation estimate as field life progresses.
Proved Undeveloped Reserves (external reporting):	Undeveloped fields	'Reasonably certain' (Low case, low activity scenario if applicable) outcome of the development concept selected and approved for execution based on Expectation 'Proved Area' volumetrics.
	New, recently developed fields:	'Reasonably certain' (Low case) outcome of the incremental development ahead, based on Expectation 'Proved Area' volumetrics.
	Mature fields:	'Reasonably certain' (Low case) outcome of the incremental development ahead, based on Expectation 'Proved Area' volumetrics. The Proved Undeveloped Reserves estimate may approach the Expectation estimate in highly mature and well-understood reservoirs. However, lower Proved : Expectation ratios should apply if the development project involves changing the recovery mechanism from that currently employed.

Figure A2.1: Group recommended practice for estimating Reserves

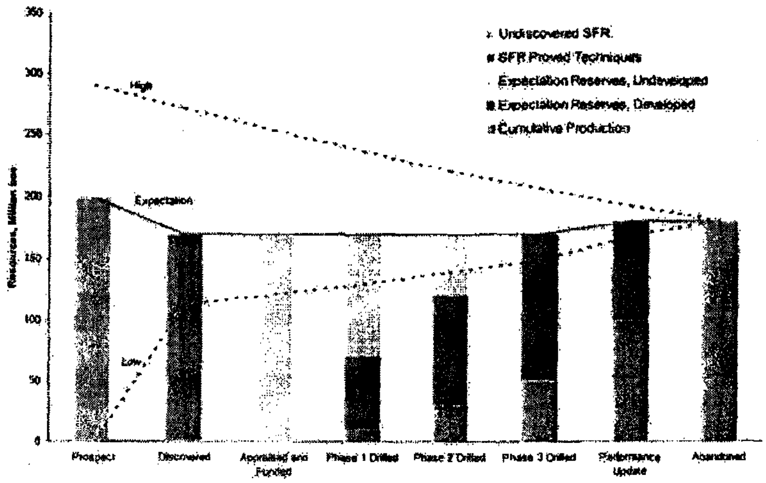
For most reservoirs it will be possible to make a robust case for reporting Proved Developed Reserves as being equal (or close to) Expectation Developed Reserves when cumulative production has exceeded some 40% of the Expectation Developed Ultimate Recovery. Lower thresholds may be appropriate for very well understood reservoirs, with copious local, direct analogue data. Similarly, higher thresholds may be appropriate for reservoirs in which relatively novel (but still "proved") recovery techniques are being employed, or when circumstances dictate that a more cautious approach be taken to Proved Reserves estimation.

A2.3 Further Considerations

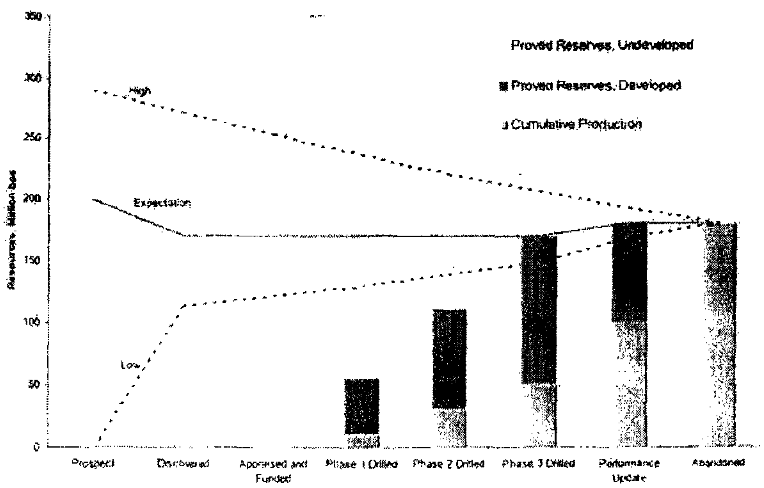
A2.3.1 Uncertainty Reduction with Performance

The uncertainty range of Ultimate Recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. **As a field matures, initial in-place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range.** Once reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation (subject to 'Proved Area' conditions).

The following diagram illustrates the reduction in uncertainty for Resource Volume estimates (including cumulative production) over the lifetime of an asset:



For the above example, the Proved Reserves (taking account of cumulative production) profile as disclosed externally might be as follows:



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A2.3.2 Addition of Proved Reserves Volumes

Proved Reserves are aggregated at various levels (reservoirs, fields, areas, etc) during the Resource Volume assessment and reporting process. When Proved Reserves are based on p85 or Low estimates, such addition could in principle either be arithmetic or probabilistic.

Arithmetic addition usually overstates the uncertainty range for the sum of (partially) independent volumes (i.e. the resulting sum of p85/Low values is too low), but it is appropriate for dependent volumes.

Probabilistic addition could be considered for partially independent volumes when the difference with arithmetic addition is significant. An important requirement is, however, **that addition of Proved Reserves at or above the level used for financial depreciation calculations must be arithmetical for consistency with financial accounting.** Below this level, i.e. normally below the field level, an appropriate selection of the addition method must be made, such that account is taken of dependency between the volumes to truly reflect the aggregated p85/Low/Proved recoverable volume.

Below are two examples where the method of addition is important to handle addition properly.

a) Field A consists of separate layers and the properties of these layers are independent of each other. In other words, a low result in one layer would not increase or decrease the chance of a low result in the other layers. Low, expectation and high estimates are calculated for each layer separately. Probabilistic addition should be used to account for the reduced uncertainty of adding together independent volumes. Arithmetical addition of these estimates would understate the low estimate and overstate the high estimate of the total field.

b) A project develops three independent fields as sub-sea satellites connected to one platform. In this case, the investment in surface facilities may be totalled for depreciation[1] and consequently the reserves estimates should relate to the combined fields. Probabilistic addition should be used to calculate the total reserves associated with the platform (assuming independence).

Please refer also to Appendix 1.

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields for depreciation purposes.

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A2.3.3 Production Forecasts

The following notes are intended to guide the preparation of production forecasts in support of Resource Volume reporting and in particular in support of Proved and Expectation Reserves reporting.

The basis for all Resource Volume reporting is either an existing producing asset or a "project", however notionally defined.

Resource Volume estimates should preferably be supported in all cases by a production forecast for the corresponding reservoir development scenario, linked to a specification of the recovery process, the number and type of wells necessary, facilities requirements and the costs of installing and operating the required wells and facilities.

The production forecasts should be defined at a level of resolution that is appropriate for the needs of the business and the maturity of the assets concerned: for example reservoir unit, reservoir or field.

Account should be taken, where necessary, of overriding constraints, such as evacuation system capacity, (likely) OPEC quota levels or funding levels, particularly if these affect the timing of development activities and the Resource Volume for the project concerned is dependent on the timing of execution.

The aggregation of all production forecasts for Expectation Resource Volumes should reflect the overall business plan for the collection of assets in question.

It is recommended to construct Proved production forecasts for each asset, not least because in principle this is required to create the Standardized Measure of Discounted Cash Flow for external disclosure and to reliably estimate volumes producible within the licence period (external Proved Reserves disclosures must be constrained by licence expiry – see section 3.3.1 of main text).

Where Proved Reserves are based on reservoir modelling, the Proved production forecast should be based on a specific modelled Proved Reserves scenario.

The Proved production forecast for Developed Reserves should equal the Expectation production forecast at its starting point and thereafter it should gradually fall further and further below the Expectation production forecast (in cases where Proved Developed Reserves do not equal the Expectation estimate). The Proved production forecast for Undeveloped Reserves may commence at a lower level than the Expectation production forecast to reflect uncertainty in the initial production rate.

When expressed in terms of rate versus cumulative production, the Proved production forecast should never exceed the Expectation production forecast.

The aggregated Proved production forecast for a business or collection of assets should at no point in time exceed the aggregated Expectation production forecast (i.e. the business planning forecast), unless there are clearly defined circumstances that would make it possible for this to happen.

APPENDIX 3 SEC RESERVES AUDITS - TERMS OF REFERENCE

The purpose of the Proved Reserves Audit is to verify that appropriate processes are in place in the asset holder to ensure that the Proved and Proved Developed Reserves estimates for external (SEC) reporting are compliant with the Group guidelines.

The Audit will be carried out by the Group Reserves Auditor. His specific tasks during the audit shall be:

1) To verify the technical maturity of the projects and activities that underlie the reported proved and proved developed reserves estimates by assessing the quality of the engineering data and study work supporting the estimates.

2) To verify the commercial maturity of the reported reserves volumes by assessing consistency between the volumes reported and the company's business planning (production/sales forecasting), ensuring that these volumes can reasonably be expected to be (developed, produced and) sold in present or future markets.

3) To verify the 'reasonable certainty' of the reserves estimates by assessing the validity of uncertainty ranges used for their constituent parameters, by verifying that estimates are realistic in comparison with expectation estimates, by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied. The audit also verifies that implied future development is indeed likely to go ahead.

4) To verify that the Group share of proved and proved developed volumes has been calculated properly and are producible within prevailing licence periods.

5) To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in the appropriate categories and that appropriate audit trails are in place for the study work supporting the reported reserves estimates.

6) To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance.

In case of deviations from the Group guidelines the auditor shall establish whether and to what extent resulting estimates are likely to differ from those that might be expected from the 'proper' application of the guidelines.

The frequency of the audit will in principle be once every four years for each asset holder, but should be adjusted as warranted by size of asset holder, past change volumes and complexity of the issues. Major reserves changes or concerns expressed during a previous audit may require an advancement of the next audit. For an asset holder reporting reserves for the first time, the first audit will in principle be within two years of this first submission.

The audit will in principle be carried out on asset holder premises and will be based on documentation available in the asset holder. The audit will be carried out by reviewing the reserves estimation and submission process through interviews of asset holder staff and by taking a number of selected fields for more detailed technical analysis.

An audit report will be submitted to the Managing Director and Petroleum Resource Manager of the asset holder (where appropriate), to the EP CEO and Regional Technical and Finance management and to KPMG the external auditors. It will be prepared and discussed in draft form on site, after which a final report will be prepared in The Hague, once formal asset holder comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 4 TERMINOLOGY

A4.1 Petroleum Resources Terminology

Reservoir

A reservoir is a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

In case of doubt, reservoirs are restricted to fault blocks or sedimentary units that have been proved to be productive until production performance proves communication to exist across faults or other barriers.

PVT properties can vary within a reservoir.

Field

A field is an area consisting of a single reservoir or multiple reservoirs within a closed areal boundary that belong to the same confining geological structure.

Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.

Potential Accumulations

Potential reservoirs beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.

Hydrocarbons Initially in Place

The volume of hydrocarbon which is estimated to exist (or have existed) originally in a naturally occurring accumulation at the time of its discovery. The volume is usually expressed at standard conditions of temperature and pressure (or, sometimes for gas, "normal" conditions of temperature and pressure) taking account of volume and phase changes that would occur were the entire hydrocarbon content of the accumulation to be brought to those conditions. It is also usual to specify the volume separately for each hydrocarbon product at the reference conditions, usually oil, natural gas liquids and gas (which may be further subdivided into gas occurring in the gas phase at original reservoir conditions – "non-associated gas" or "free gas" – and gas that forms a part of the liquid phase at original reservoir conditions – "associated gas" or "solution gas"). It is also usual to quantify the range of uncertainty associated with the estimate (see A4.2).

Ultimate Recovery

The sum of cumulative production and the estimated reserves. The definition may be qualified to indicate the use of Proved Reserves, Expectation Reserves or Expectation Reserves Within Licence as required. It may be further qualified to include either developed reserves or total reserves (developed + undeveloped). It may also be defined as including (and, for immature reservoirs, may consist entirely of) SFR volumes. From the foregoing it should be clear that whenever Ultimate Recovery figures are quoted, they should be defined and qualified with the same rigour as resource volumes.

Recovery Factor

The Recovery Factor is the ratio of Ultimate Recovery to Hydrocarbon Initially in Place, expressed as a fraction or percentage.

Natural Gas Liquids

Natural Gas Liquids (NGLs) are hydrocarbons existing in the liquid phase at standard conditions of temperature and pressure ("stock tank" conditions), but which formed a part of the gas phase at original reservoir conditions, and which are recovered from the production facilities.

In some cases, NGLs are spiked into oil for export and sales purposes: in these cases it is recommended that the NGLs are still accounted for separately.

Liquefied Petroleum Gas (LPG) products, which exist in the liquid phase at the point of sale but which would evaporate if flashed to standard conditions of temperature and pressure, should be accounted for as *gas*.

Economic Producibility

Economic producibility should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.

Production Facilities

Production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.

Surface Facilities

That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.

Existing Development

The collection of all completed projects or sub-projects is referred to as the existing development.

Field quantities

Field quantities (also called 'Wellhead' quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalized sales and other product outlets, see below.

Sales quantities

The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.

Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.

For general sales products, oil, gas and NGL, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such can be reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. In principle all non-oil hydrocarbons that are sold as separate streams in liquid state (pressurized or not) should be accounted as NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). In line with SEC requirements, sales volumes for gas should be those committed or committable to a gas contract. Committed Gas is covered by a gas contract. Committable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: (1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+ etc., or (2) If there are special sales products like helium, sulphur or generated electricity.

Reconciliation

A monthly reconciliation is made between the fiscalized sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield.

For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).

A4.2 Probabilistic Terminology

Probability Density Function

The probability density function (PDF) of a stochastic variable indicates the probability that the actual variable value lies within a narrow interval around a particular value of the possible range.

Cumulative Probability Function

The cumulative probability function (CPF) of a stochastic variable describes the probability that the variable may exceed a certain value. The CPF is the mathematical integral of PDF.

p85

The value that has a 85% probability of being exceeded by any randomly selected value in a range.

p15

The value that has a 15% probability of being exceeded by any randomly selected value in a range.

Mean (Expectation)

The statistical mean of a random variable is the probability-weighted average of the variable over its entire range.

Commercial Cut-off Volume

The commercial cut-off volume is that resource volume for which the development NPV (Net Present Value) is equal to zero at the Mid PSV of oil or gas price.

Probability of Success (POS)

When applied to an undrilled potential accumulation (Undiscovered SFR), POS expresses the probability that the accumulation will contain resource volumes exceeding a certain volume ("cut-off"):

POS at zero cut-off: The probability of finding hydrocarbons.

POS at commercial cut-off: The probability of finding a the minimum resource volume required for commercial development. The POS at commercial cut-off can never exceed the POS at zero cut-off. Please refer also to the definition of "Commercial", A4.3 below.

Mean Success Volume (MSV)

The Mean Success Volume (MSV) is the mean of all success-case volumetric outcomes. The MSV of a prospect depends on the (volumetric) cut-off that has been applied and therefore should always be quoted with reference to that cut-off.

See also Probability of Success (POS).

The expectation resource volume (Undiscovered SFR) associated with an undrilled potential accumulation is the product of MSV and POS at commercial cut-off.

A4.3 Commercial Terminology

Commercial

When applied to SFR, *Commercial* denotes SFR that is associated with a project that is evaluated as having a positive Net Present Value (NPV) of development (i.e. excluding exploration and appraisal costs) at the prevailing Group Mid PSV of oil and gas price and for which there is the reasonable expectation that any remaining obstacles to development can be overcome (e.g. securing gas sales contracts, provision of major infrastructure, government approvals, unproven technology).

Non-Commercial

When applied to SFR, *Non-Commercial* denotes SFR that is associated with a project that is evaluated as having a negative Net Present Value (NPV) at the prevailing Group premises assumptions or for which there are clear obstacles to development that at present appear to be insurmountable (see definition of "Commercial").

Discount Rate

A rate at which future real terms costs or cash flow are discounted over time to calculate their present value.

Net Present Value (NPV)

The net present value of a project is the sum of the discounted cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.

Expected Monetary Value (EMV)

The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree).

The EMV is the summation of the NPVs of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate.

Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.

Unit Technical Cost (UTC)

The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

FID

Final investment decision, the decision (at CMD or senior executive level) to proceed with a project.

NFA forecast

No further (Capex) activity forecast, i.e. a forecast based on existing wells and facilities only.

A4.4 Exploration and Development Wells

The classification of a well as either an exploration well or as a development well is determined (in line with SEC rules) based on the proved area as follows:

Proved Area

The proved area is the part of a property to which Proved Reserves have been specifically attributed (see also Appendix 1). It is delineated by the fluid levels seen / interpreted from drilled wells and by the area around those wells which geological / engineering data indicate to be producible.

Development Well

A development well is a well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

Service Well

A service well is either an injection well, a disposal well or a water supply well.

Appraisal Well

An appraisal well, or stratigraphic test well is a well drilled for geological information (not to test a prospect), either 'development-type' drilled in a proved area or 'exploratory-type' if not drilled in a proved area.

Exploration Well

An exploration well is a well that is not a development well, a service well, or a stratigraphic test well.

Exploration Expenditure and Capital Expenditure

For details of the allocation of costs between Exploration Expenditure and Capital Expenditure, please refer to the Group Financial Information Manual (GFIM, Ref. 10). In simple terms, Exploration Expenditure includes all costs incurred in drilling wells to locations that fall outside the Proved Area.

APPENDIX 5 NEW CLASSIFICATION SYSTEM

With effect from 31.12.2004 the Petroleum Resource Volume Classification System will be revised as indicated below (see section 2.2 of main text for comparison). The changes relate to an expansion of the SFR categories, so as to provide more useful information on the maturity of the Resource Volumes concerned. At 31.12.2003, year-end Resource Volume balances should be sub-divided into the new categories to form opening balances for the reporting of changes in 2004.

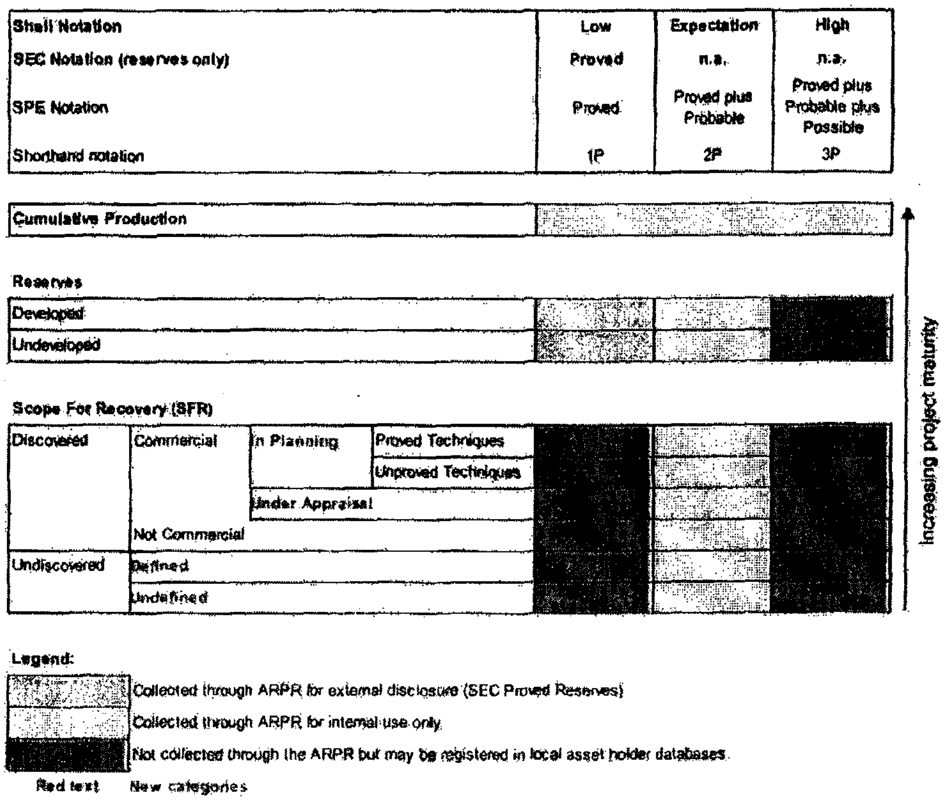

Figure A5.1: Overview of proposed new Shell Petroleum Resource Classification System

The purpose of introducing further resolution into the SFR Undiscovered category is to highlight the more mature elements of the exploration portfolio. The changes to the SFR Discovered category are intended to give greater insight into the maturity of projects for discovered resources *en route* to development FID.

Definitions of New SFR Categories

SFR Undiscovered: Undefined

SFR Undiscovered resource volumes that are not specifically attributable to a potential accumulation that has been mapped.

This category describes notional volumes that are anticipated to be present based on, for example, play maturity modelling (for example, inferences based on existing discovered field size distributions), but which cannot yet be assigned to any identified prospect or lead. There should be a reasonable likelihood that any such resource volumes would be commercial to develop.

SFR Undiscovered: Defined

SFR Undiscovered resource volumes that are identified with mapped potential accumulations (prospects and leads).

SFR Commercial

Within this category, project maturity can vary considerably and the new sub-divisions are designed to provide greater transparency on the distribution of Resource Volumes on the "maturity" scale.

The pre-existing SFR Proved Techniques and SFR Unproved Techniques will now be reserved for projects that are at a relatively late stage of Field Development Planning: these will be grouped and referred to as "In Planning". Typically these will be projects that are being actively worked through concept selection towards VAR3 (they will generally have already passed VAR2) or for which Field Development Plans are being prepared for FID.

For projects that are not sufficiently mature to qualify under these (revised) pre-existing categories, a new category will be created:

SFR Discovered: Under Appraisal

SFR Discovered resource volumes that are associated with a field or project that is subject to ongoing appraisal or the evaluation of exploration or appraisal results.

This category describes new (or recent) discoveries: partially appraised fields or unappraised discoveries. This category generally covers projects up to VAR2. Upon completion of further appraisal and / or evaluation studies, the project would either be declared Non-Commercial or it would pass to the "In Planning" category and from there to Reserves.

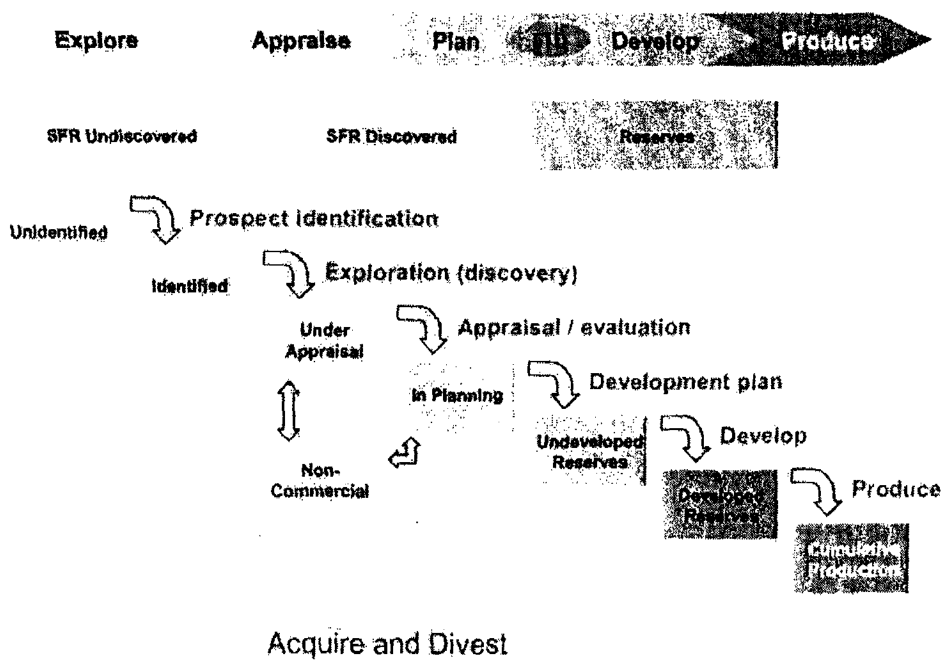

Figure A5.2: New resource volume classification flow diagram

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