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1. INTRODUCTION

Petroleum resources represent a significant part of the company'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.

Shell Group petroleum resource volumes and their anticipated changes are reported to Excom on a frequent basis. Proved reserves have a direct influence on net income, are disclosed externally and therefore subject to internal controls and external audit.

This document represents the petroleum resources accounting standard for Shell Group Operating Units (OU's) and New Venture Organizations (NVO's). It complies with rules set by the US Securities and Exchange Commission (SEC) and is to serve as a reference in the reserves submission, reporting and control processes.

Information on the format requirements of internal and external submission will be included in the second part of these guidelines (SIEP 2002-1101, Ref. 3). Detailed submission requirements are communicated annually in a letter from EP Planning.

The present (2002) version addresses recent clarifications of SEC definitions published by SEC staff. The text has also been shortened to promote clarity and readability. Where text has been changed or added, this is indicated by a line in the margin.

No material change in the volume of reserves reported by the Group is expected nor intended by these guidelines.

2. RESOURCE VOLUME CLASSIFICATION

2.1 Definition

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

Resource volumes are reported as the quantities of sales product for crude oil, natural gas and natural gas liquids. The corresponding quantities of field recovery should be maintained by the OU (See Appendix 6). The reporting of petroleum resource volumes should further indicate the petroleum type, the reporting units and conditions, and the Group share.

2.2 Reserves and SFR (Figure 1)

Resource volumes are tied to the project or activity that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is **technically and commercially mature** to the extent that funding is 'reasonably certain' to be secured. Resource volumes that do not meet these criteria are classified as **Scope for Recovery** (SFR). **Proved reserves** are the portion of reserves that is reasonably certain to be produced and which will be reported externally. If no Proved reserves can be assigned to a project, then the related resource volumes are to be retained as SFR.
The concept of 'reasonable certainty' requires 'hard' field data, contracts and thorough evaluation to underlie the numbers. The implication is that as more data becomes available, upward revision is much more likely than negative revision.

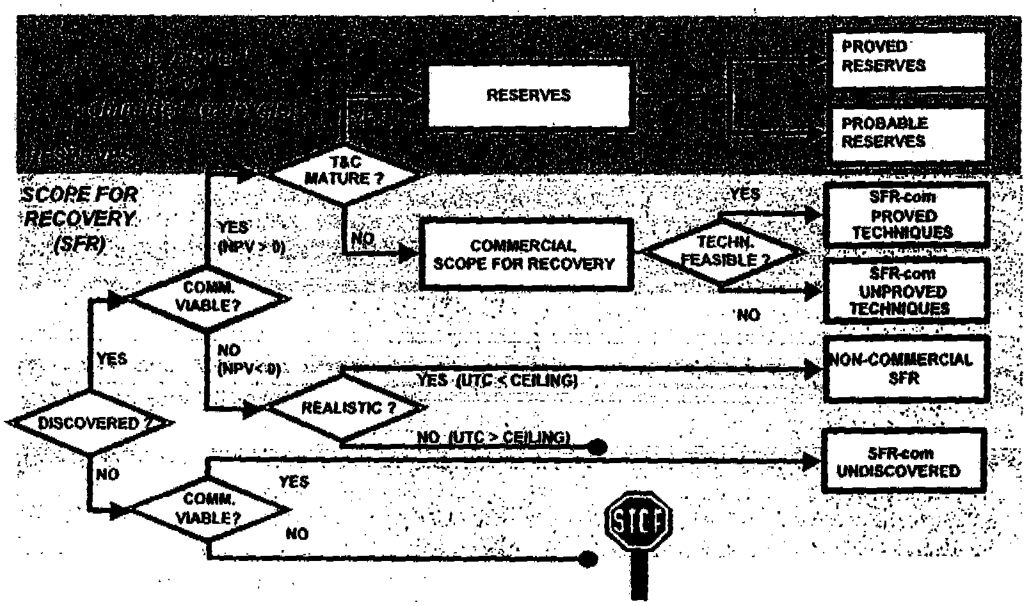

Figure 1: Resource classification flow diagram

These categories are further explained in this Chapter and their definitions are summarised in Appendix 1. A graphical example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.

2.3 Technical and Commercial Maturity

For a resource volume to pass from scope for recovery (SFR) to reserves (for internal as well as external reporting), the associated project(s) will have to reach both **technical** and **commercial maturity**. This is deemed to be the case when:

1. The Shell shareholder assurance processes have been satisfactorily passed both technically and commercially and no significant issues that could preclude proceeding with the project exist[i].
2. Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan.

Major reserves volumes that are no longer judged to be commercially mature should only be de-booked after thorough (re-)evaluation.

2.3.1 Project Basis

Reserves being future hydrocarbon product available for sale are tied to projects (development) and activities (production operations). A project is any planned creation or modification of wells, surface production facilities and/or production policy, aimed at changing a company's sales product forecast. The aggregated production forecast of an OU must therefore be consistent with its reported reserves. This also holds for the 'proved forecast', as defined by the aggregated 'reasonably certain' amount of hydrocarbons forecast to be produced by the appropriate development/production scenario, duly respecting license duration and overall constraints (e.g. quota).

2.3.2 Technical Maturity

For a project to be **technically mature**, there should be a documented definition of a viable project that is anticipated to be implemented with 'reasonable certainty'. Such project definition should be based on resource and development scenario descriptions, with drilling/engineering cost estimates, a production forecast (including sensitivities) and economics.

For project reserves to enter into the Proved category, independent review and challenge is required (as a control) to preserve integrity of the external disclosures. For major projects such review is routinely executed through the Group's Value Assurance Review process. Note that concept selection (VAR3) must at least have been completed. In all cases, there should be 'reasonable certainty' that nothing is standing in the way of a firm development plan (i.e. there are no technical issues that could de-rail the project).

For smaller projects a documented development plan should suffice, which may be notional if a well established analogue is in place. The quality of such plan should be a sufficient basis on which to judge the likelihood of project funding (see below).

2.3.3 Commercial Maturity

A project is deemed **commercially mature**, when (1) its profitability meets the Group's criteria (as applied through Shell's corporate Capital Allocation process), (2) market availability is assured (see below) and (3) funding by the Group is 'reasonably certain'.

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[i] Examples: Gas sales contracts, major infrastructure needs, government approvals, un-tried technology

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 gas this means that the product is:

1) contracted to sales; or
2) considered as reasonably certain of being sold based on an expectation of the availability of markets, along with transportation/ delivery facilities.

For major gas projects critically dependent on new gas market capture, reserves booking should in principle be deferred until agreements have been signed, which is generally at or around project sanction (FID).

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

2.4 Proved, Probable and Expectation Reserves

Total (Expectation) reserves are subdivided in Proved and Probable reserves. It should be emphasized that if no Proved reserves can be assigned to a project, then the related petroleum resource volume should be retained as SFR, i.e. there should be no Expectation reserves reported without Proved reserves.

2.4.1 Proved Reserves

Proved Reserves are the portion of Expectation reserves that is reasonably certain to be produced and which will be reported externally, as part of annual reports and (financial) accounts. The concept of 'reasonable certainty' requires 'hard' field data (incl. logs, pressures, (test) production, injection etc.), contracts and thorough evaluation to underlie the numbers. The implication is that as more data becomes available, upward revision is much more likely than negative revision. As fields mature, Proved reserves are expected to 'grow' towards (and in most cases become equal to) Expectation estimates. Quantification of uncertainty and estimation approaches are discussed in Appendix 4.

2.4.2 Probable Reserves

Probable reserves are the portion of **Expectation reserves** that is not (yet) Proved but is part of the production plan for existing fields and projects; alternatively defined as the difference between Expectation and Proved reserves.

2.5 Developed and Undeveloped Reserves

Developed and Undeveloped reserves should be evaluated separately. Assessment of undeveloped reserves on the basis of an assumed recovery factor is not acceptable.

2.5.1 Developed Reserves

Developed reserves must be 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 to 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, the developed reserves will be based on pre-development (simulation) model projections, updated for observed well geological and petrophysical data and well rates. The resulting forecast should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (NFA forecast).

2.5.2 Undeveloped Reserves

Undeveloped reserves 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 2.3).

Gas volumes that require installation of planned or anticipated future compression should be classed as undeveloped until such compression has been installed.

New development projects, which add developed reserves, 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 new development project and should be included in reserves when commercially viable.

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, field life), the additional reserves should be classified as undeveloped until this investment has been made.

2.6 Scope for Recovery

Scope for Recovery is the recovery estimate of any (notional) project, which has not reached technical as well as commercial maturity. However, there must be an expectation that this project could mature, based on reasonable assumptions about the success of further appraisal, emerging technology development, cost reduction strategies, marketing efforts, terms and conditions improvement and/or any other issue that may preclude the project's FID.

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

Scope for recovery is to be reported as a single best estimate (or a Mean Success Volume), discounted to take due account of the risk that the project will not materialise (for either technical or economic reasons).

2.6.1 Commercial SFR by Proved Techniques

The volume estimated to be recoverable from discovered resources by a project utilising a recovery process or technique which has been demonstrated to be technically feasible in the resource concerned or under analogue conditions and is expected to be economically viable.

2.6.2 Commercial SFR by Unproved Techniques

The volume estimated to be recoverable from discovered resources by a project utilising 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. Once technically feasible, the process should be expected to be commercially viable.

2.6.3 Undiscovered Commercial SFR

The volume believed to be recoverable from as yet undrilled potential accumulations by any process that has been demonstrated to be technically feasible elsewhere, under similar conditions. Development should be expected to be commercially viable.

These SFR volumes must be discounted for the risk that petroleum is not present or is not commercial to develop (Probability of Success, see Appendix 6).

Future data gathering may result in a total write-off of these resources. Following drilling results, the resource volumes are revised and, in the case of a discovery, the economics re-assessed, whereupon the resource is either discarded or reclassified.

2.6.4 Non-Commercial SFR

The volume that may be produced by development projects which, even if (technically) viable, would not be commercially viable. To avoid unrealistic situations the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical Cost below a ceiling, 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 for flared/vented/re-injected gas volumes).

3. GROUP SHARE

Only the Group share of resource volumes is reported, both in submissions for internal and for external reporting. The 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 OU or 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 an OU/NVO has interests in several licence areas subject to different contract types, a separate submission must be made with respect to Proved reserves for each of the contract types. This applies in particular to submissions for external reporting (see Figure 2).

3.1.1 Equity

Equity resources are the OU/NVOs share of resources in Concessions. Concession agreements lay down the general terms and conditions of operation, define the applicable tax rules, the Company share of resources in Concessions 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).

3.1.2 PSC Entitlement

Entitlement resources are the OU/NVOs share of production in acreage governed by a Production Sharing Contract (PSC). The Company entitlement share of production is the Company 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.

3.1.3 New Contracts

In recent years, 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 if all three of the following conditions are met:

1. The reporting Company participates in the production operations as either operator or in partnership with the operator, and so bears a share of the costs and risks of the production operations.

2. The reporting Company derives future economic value that is directly related to the volume of hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount per barrel of production would constitute a derivation of value from the produced hydrocarbons, but an operating fee that is largely independent of production would not. The actual source of revenues used to pay the OU is not crucial to this point. For example, if the remuneration is determined by a produced gas volume but paid from oil revenues, the economic value to the OU is in effect derived from the produced gas, and this volume should be reported.
3. The reporting Company is exposed to the normal risks and rewards associated with ownership of mineral rights, including the downside and upside from changes in the value of future production volumes. These include the risk that costs may not be recovered, due either to uncertainty as to the presence or magnitude of hydrocarbon volumes or to movements in petroleum prices.

OUs and NVOs working under such contracts should complete the standard resource volume submission for the Group/Company 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. 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 below).

When an OU is participating in a venture which grants neither title, nor an entitlement to receive petroleum, and which does not satisfy the three criteria above, the OU should not report reserves or production volumes. 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 OU

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 also be accounted for in the reserves submission.

As an exception to this, both Expectation and Proved reserves (internal and external reporting respectively) are reported on a 100% basis for companies in which the Group holds a controlling (> 50%) interest, consistent with financial reporting. Minority interest volumes included in these total reserves are then disclosed separately. Prior agreement must be obtained from Group Finance before such reporting is considered.

3.3 Licence duration and other restrictions

3.3.1 Licence or Contract Extensions

For internal reporting purposes, Group shares of the Expectation estimates of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, that is not (yet) covered by a right to extend or by a letter of assurance (see below). The currently existing licence terms or other anticipated terms should be assumed for this extrapolation. In addition to these full life cycle volumes, resource volumes are also recorded as limited to the current licence or its agreed extension only (Expectation developed reserves, total Expectation reserves and commercial SFR).

For external reporting, Group share of reserves (Proved, Proved Developed) is limited to future production within the existing licence or contract period, including any agreed extensions as may be covered by documented evidence.

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.

3.3.7 Under/Over Lift

Group share should also allow for any historic under 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 impact of swap deals between fields where early production capacity in one is traded versus later production repayment by the other.

Treatment of take-or-pay volumes should be aligned with financial treatment of the cash received and booking of production volumes.

3.3.8 Open Acreage

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

3.3.9 Committed Gas Reserves

Total volumes of expectation gas reserves within licence, which have been sold (committed) under long and short term contractual agreements. In countries with a mature/deregulated gas market all gas reserves which have a near certainty of market take-up can be classified as 'committed'.

3.3.10 Committable Gas Reserves

Volumes of gas reserves, which have not been sold, but could be sold (committable) under contractual agreements. The sum of committed and committable gas reserves should equal expectation gas reserves within licence.

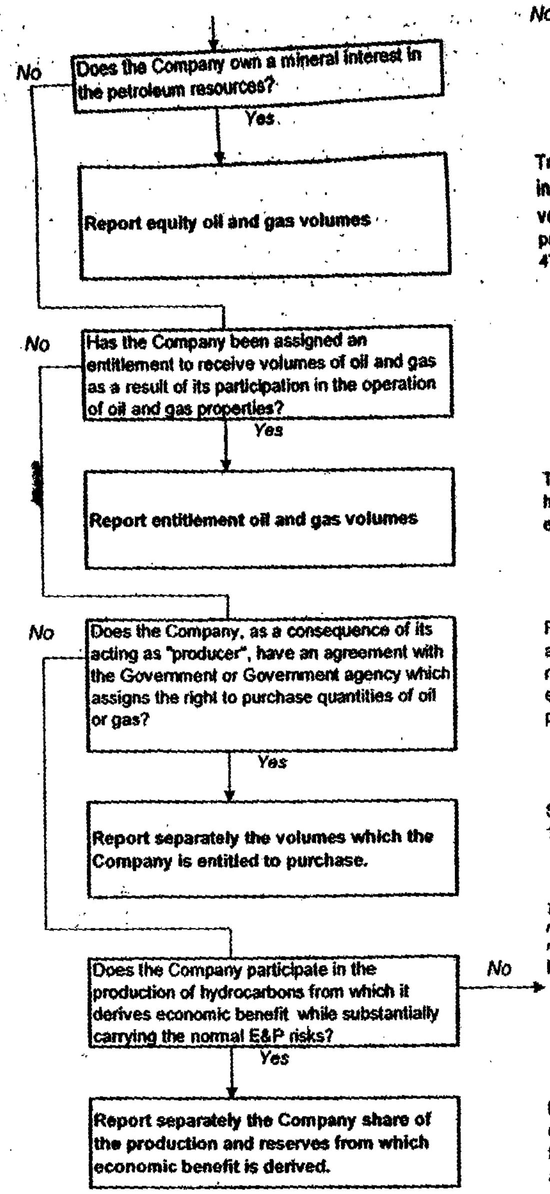
3.3.11 Gas Re-injection

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 estimates. These gas volumes should be classified and reported as reserves or SFR, depending on the recovery anticipated through future developments (e.g. taking into account anticipated re-saturation losses).

Gas volumes re-injected in an 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.

3.3.12 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 should also include 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.



Notes

Traditional meaning of an enterprise's interest in reserves (FASB 19 para.10). Exclude volumes payable to others through production payments or carried interests (FASB 19 para. 47a and d).

Typical PSC case. Whether the Government has a pre-emptive right to buy back these entitlements is not material.

Relevant where national legislation prevents access to mineral rights. The agreement would not be a consequence of acting as producer if e.g. others have similar agreements but do not participate in production operations.

Separate disclosure is required. FASB 69 para. 13.

The following are interpretations of the principles of the FASB regulations regarding Company interests in production & reserves;

No volumes reported.

Normal E&P risks refer to both downside and upside exposure to changes in the value of future production volumes due to uncertainties as to their presence, volume and price.

Figure 2: Types of External Disclosures in Relation to FASB Regulations

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4. ASSESSMENT, REPORTING, RESPONSIBILITIES AND AUDITS

Resource classification and reporting is meant to support the company decision-making 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.

OUs or NVOs 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 preserve integrity of reporting,

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

e) Record Key Performance Indicators (KPI's) 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 to OUs and NVOs a timetable and details about submission requirements for both internal and external reporting.

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

4.2 Methods and Systems

OUs and NVOs 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 resource volume guidelines.

4.3.2 Reserves Auditor Responsibilities

The Group Reserves Auditor will carry out regular detailed reserves audits in OUs and NVOs to verify compliance with the Group's guidelines. The Terms of Reference for such audits are included in Appendix 5. In addition the Group external auditors will verify the Proved reserves data for external (annual corporate) reporting.

4.3.3 Operating Unit Responsibilities

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

All levels in an OU, including Asset managers and the reservoir engineer preparing the individual field reserves estimates, should be aware of the importance of externally reported reserves (Proved, Proved developed) and their impact on financial indicators.

Asset and OU managers are responsible to ensure that the guidelines are implemented in such a way as to best represent to the shareholders the true value of the asset.

4.3.4 Non-operated Reserves

Where Shell is not the operator, the Shell company that holds the interest/share in the venture is responsible for the preparation of the reserves submission. In this case the Shell company involved has the responsibility of 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 and re-evaluation of proved reserves.

4.3.5 Audit Trail

Audit trails form an essential element in the reserves reporting process and are an indispensable tool for the Group Reserves Auditor to assess the quality of the reserves estimates. They should support and document the submitted figures and ensure that OU management understand and own the reserves submissions to SIEP. They also form an essential link in handing over resource estimates between field reservoir engineers and reserves co-ordinators and their successors.

For all the reported 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' in order 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, SIEP 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).

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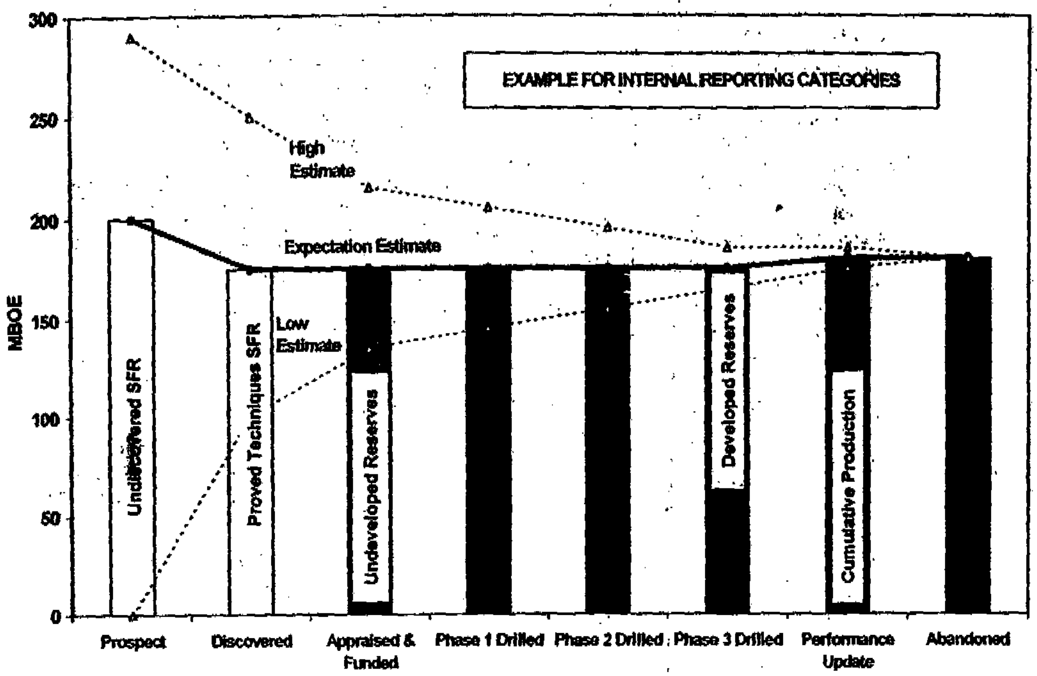
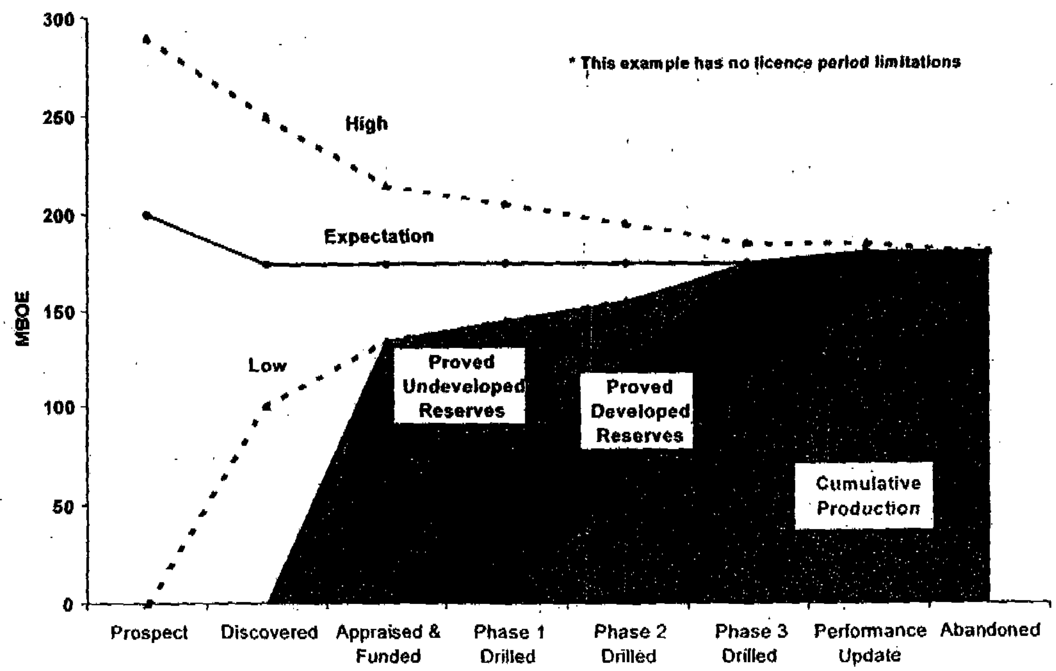
APPENDIX 1 RESOURCE CATEGORY (QUICK REFERENCE)

External Reporting	Internal Reporting	Proved Reserves		Portion of internally reported Expectation reserves (see conditions below), that is 'reasonably certain'. Additional conditions: Restricted by licence periods, government constraints and market limitations. Deterministically estimated volumes should reflect undefined fluid contacts and untested recovery mechanisms ('proved area').
External Reporting	Internal Reporting	Proved Reserves	**Proved Developed Reserves**	Proved reserves producible through existing completions and installed facilities using existing operation methods. Consistent with 'proved area'. Outstanding project activities considered completed if remaining cost < 10% of total. 'Behind pipe' volumes only if cost < 10% of well cost.
External Reporting	Internal Reporting	Proved Reserves	**Proved Undeveloped Reserves**	Proved reserves which require future capital investment (wells and/or facilities). Consistent with 'proved area'. Recovery techniques to be proven in same or analogous reservoirs.
	Internal Reporting	Expectation Reserves		Project is 'technically and commercially mature' and funding 'reasonably certain'. Volumes to be consistent with business planning and production/sales forecast. Includes only production with positive cash flow. Not restricted by licence period. Group share only reported.
	Internal Reporting	Expectation Reserves	**Developed Reserves**	Reserves producible through existing completions and installed facilities using existing operation methods. Outstanding project activities considered completed if remaining cost < 10% of total. 'Behind pipe' volumes only if cost < 10% of well cost.
	Internal Reporting	Expectation Reserves	**Undeveloped Reserves**	Reserves which require capital investment (wells and/or facilities)
	Internal Reporting	Scope for Recovery		Project is technically or commercially not mature Not restricted by licence period. Group share only reported.
	Internal Reporting	Scope for Recovery	**Commercial SFR by Proved Techniques**	Discovered. Commercially viable. Techniques have been proved to be feasible in this resource or analogous field. A sound technical project proposal is not possible yet due to large range of technical uncertainty and/or market constraints.
	Internal Reporting	Scope for Recovery	**Commercial SFR by Unproved Techniques**	Discovered. Commercially viable. Recoverable by novel techniques or techniques that have been successful elsewhere, but cannot yet be demonstrated to be feasible in this field. R&D activities stand a reasonable chance of demonstrating feasibility in this field. Discounted for the risk that the considered technique will not prove to be feasible.
	Internal Reporting	Scope for Recovery	**Non-Commercial SFR**	Discovered. Not commercially viable even if technically successful. Commercially viable with a change of commercial circumstances. Unit Technical Cost below an annually advised ceiling.
	Internal Reporting	Scope for Recovery	**Undiscovered Commercial SFR**	Recovery from undrilled prospects. Commercially viable exploration and development. Techniques have been successful elsewhere under similar conditions. Discounted for the risk that commercial volumes are not present.

APPENDIX 2 RESOURCE MIGRATION DURING FIELD LIFE



EXAMPLE FOR EXTERNAL REPORTING CATEGORIES *



APPENDIX 3 PROVED RESERVES – SEC DEFINITIONS AND SHELL INTERPRETATIONS

	SEC Definition	Shell Group Interpretation
1.	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 by contractual arrangements, but not on escalations based upon future conditions.	Reasonable certainty: Future revisions more likely to be upward than downward. Proved reserves to 'grow' towards Expectation estimates with increasing field maturity. Existing economic and operating conditions include identified future changes in these conditions (e.g. new developments, including abandonment), provided their costs are fully included in the project economics and planning basis. Prices and costs, see 8 below.
2.	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 that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, 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. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.	Producibility: Either through a production test / production or through log / core / fluid data analogous with other produced reservoirs in the area. Proved Area: Areas with well control, confirmed producibility (in reservoir or analogue) and continuous good quality seismic amplitudes (Ref. 13), but within potentially sealing barriers or faults. Lowest Known Hydrocarbons: OWC, GWC, GOC may be interpreted from pressures in the reservoir unit. Continuity of production should preferably be demonstrated through pressure or fluid responses in the reservoir. However, demonstrated analogy with an analogous reservoir (of same or poorer properties) can be accepted. The above conditions can be waived by conclusive reservoir evidence or performance.
3.	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.	In cases where other information (core and fluid studies, coupled with analogue field experience) provides the necessary assurance, pilots may not be necessary. However, projects must be technically as well as commercially mature (see 4.), i.e. project funding must be reasonably certain.
4.	Technical / commercial uncertainties 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, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; - 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.	Must be technically and commercially mature, which is deemed to be the case when: (1) The Shell shareholder assurance processes have been satisfactorily passed both technically and commercially and no significant issues that could preclude proceeding with the project exist. AND (2) Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan. Continuance of permits, or formal options to extend, are required. Heavy oil, bitumen, syncrude, gas, liquids, etc. recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a

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	SEC Definition	Shell Group Interpretation
		"manufacturing" process must be reported separately from the conventional resource base. However, 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).
5.	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 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 related volumes can be accounted as developed, as is the case for reserves requiring only minor well activities (< 10% of cost of new well). No special conditions for improved recovery reserves. Technical and commercial maturity must be demonstrated – see 4.
6.	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 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 (Emphasis added).	Continuity of production: see under 2. Improved recovery reserves – see 4 and 5.
7.	Analogous reservoirs (producibility) 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 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 is shown either through a production test / production or through log / core / fluid data analogous with other produced reservoirs in the area (see also 2 above). This requires positive demonstration of the applicability of the analogy to the proposed reservoir.
8.	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.)	Standardized Measure submissions based on end-year prices as advised centrally.

	SEC Definition	Shell Group Interpretation
9.	<u>Probabilistic methods</u> of reserve estimating	If the method is used, proved reserves should conform to the "Proved Area" constraint (see 1 above). Probabilistic addition should only be used (<u>subject to full 'independence' of the units</u>) at levels below those used for financial depreciation accounting.
10.	<u>Reservoir Simulation</u>	Reservoir simulation is the preferred tool for determining reserves (Proved and Expectation). In the absence of production history to match, validation by other methods (i.e. analogy) required to assure 'reasonableness'. Proved reserves must always be consistent with the "Proved Area" principle. When doubt exists, conservative values should be used.
11.	<u>Standardized measure</u> of discounted future cash flows relating to oil and gas properties must comply with para 30 of FASB	As per FASB: Based on end-year prices, full-year average operating costs, Capex as per date of estimate, discount rate 10%.
12.	Production Sharing Agreements	Proved reserves must be based on the "economic interest method" (future cost+profit oil revenue divided by Group premises oil price). Producer must have the right to extract the hydrocarbons and must be exposed to exploration / development / production risk.

APPENDIX 4 UNCERTAINTY AND PROVED PART OF RESERVES

A4.1 Quantification methods

Subsurface resource volume estimates are inherently subject to uncertainty, because they are based on 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 three most important methods to quantify and assess the range of uncertainty in resource volume estimates are:

- The Probabilistic method (P85, Mean, P15)
- The Multi-scenario method (Low, Middle, High)
- The Deterministic method (Proved, Probable, Possible)

A4.1.1 The probabilistic method

The probabilistic method has been in use by the Shell Group for more than 30 years. Whilst the Group was initially the only one in the industry applying this method, the method has, over the years, gradually gained wider acceptance, e.g. by the SPE (Ref. 6).

The method consists of assigning probability density functions (PDFs) to each of the constituent parameters that define a subsurface volume estimate (i.e. gross bulk volume, porosity, hydrocarbon fill and saturation, hydrocarbon volume factor, recovery factor). These PDFs are then combined (multiplied) either mathematically ('moment' method, see Ref. 4 - App. 7) or, more commonly, through Monte Carlo simulation. The latter method uses a random number generator which generates random selections from each of the parameter ranges, which are then combined into successive volume estimates, often numbering 1000 or more. Software tools using Monte Carlo simulation are e.g. @RISK, Crystal Ball and FASTRACK.

The resulting product from both the mathematical and the Monte Carlo methods is a PDF or its integral, the cumulative probability function (CPF), which defines the probabilities that the resource volume exceeds each of a range of values. The values associated with the 85% probability the 15% probability are called the 85% and 15% confidence levels or **P85** and **P15** for short. The probability-weighted average value is referred to as the **Mean**. 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).

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

A4.1.2 The multi-scenario method

This method is in principle applied 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. The static model is generally run for a range of possible subsurface realisations, yielding a range of hydrocarbon-in-place volumes.

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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 as a support to development concept selection.

A4.1.3 The deterministic method

The deterministic method has been the method most frequently used by the industry outside Shell. It derives from the original definitions of 'Proved Reserves' as issued by the American 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. Subsequent definitions for Probable and Possible reserves have been issued by the SPE in co-operation with the WPC (Ref. 6).

Proved reserves are defined 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 declared. This proved area is constrained by:

- Economic **producibility** demonstrated by a production test (not a wireline test!),
- Delineated by GOC, OWC, GWC if seen by drilling,
- Oil volumes above OUT levels only if gas is seen updip and a GOC can be interpreted,
- No volumes below **'lowest known hydrocarbons'** (LKH), as seen by drilling,
- Laterally confined to one 'legal location' (US regulatory minimum well spacing) away from well control,
- **Certainty** (not just 'reasonable certainty') of **continuity of production** over the area (must be demonstrated by conclusive data if beyond one 'legal location'),
- **Improved recovery** volumes only with a successful **pilot** in that specific rock volume,
- The conservative restrictions regarding LKH and lateral well control may be lifted "...upon obtaining **sufficient performance history** to reasonably conclude that more reserves can be recovered..."

The significant information on reservoir structure and hydrocarbon fill available from modern seismic techniques (DHIs, flat spots etc) is acknowledged by the SEC, but the staff emphasize the above constraints unless there is strong analogy with a nearby producing reservoir (Refs. 8 & 14).

The practice in the industry outside Shell 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. The important consequence of this has been that Proved reserves as calculated by the deterministic method tended to be lower than probabilistic P85 estimates for new discoveries and undeveloped fields. Similarly, they were generally higher for mature, fully appraised fields.

The SPE (Ref. 6) recommend that, if Proved reserves are determined probabilistically, a P90 value be selected. They generally align with the SEC guidance, except that they allow areas beyond the regulatory well spacing to be included if "...data from wells indicate with reasonable certainty (P90) that the objective formation is laterally continuous and contains commercially recoverable hydrocarbons...".

The SPE/WPC definitions of Probable and Possible reserves (together called Unproved reserves) can be summarised as follows:

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 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) should be classified as SFR in the Shell system.

A4.2 Shell Group Practice

Shell Group practice has long been based on the probabilistic method as the Group standard for estimating Expectation reserves (for internal reporting). Proved reserves (for external reporting) were set equal to the (volumetrically based) P85 estimates, which changed little as fields matured. This approach was found to lead to underreporting against major competitors and was replaced by a deterministic approach in 1998. In following the guidelines of the American Financial Accounting Standards Board (FASB) of 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).

Current practice still ascribes a portion of Expectation (internally reported) reserves to the (externally reported) Proved category. First "booking" therefore 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 as selected for execution. Proved reserves estimates should in principle be consistent with volumetrics in the 'proved area', which is defined by:

- 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,
- 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.

The thinking behind this interpretation is that the drilling and completion of development wells will generally expand the 'proved area' such that its volumetric extent will cover 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.

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 estimates (see above).

The resulting description of assumptions to be used for estimating Proved and Expectation reserves is given in Fig. A4.1. To the extent that reserves (particularly Proved reserves) are based on probabilistic estimates, consistency with these assumptions is required.

Expectation Developed and Undeveloped (internal reporting):	All fields	Mean probabilistic or Middle case outcome of the development concept (FDP to be funded) selected for execution and 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 (FDP to be funded) selected for execution based on Expectation 'proved area' volumetrics.
	Mature fields:	(Conservative) best estimate performance projection, based on Expectation post-drill + performance based on Expectation 'proved area' volumetrics. The Proved 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 (FDP to be funded) selected 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. Expected to approach Expectation as field maturity progresses. Lower Proved / Expectation ratios should however apply if the reservoir mechanisms concerned differ from the current ones.

Figure A4.1: Group recommended practice for estimating Reserves

A4.3 Further considerations

A4.3.1 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 the 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).

Figure A4.2 illustrates the narrowing of the uncertainty with field appraisal and development. This is a near ideal example where the expectation remains constant for most of the life cycle. This example is also used in Appendix 2 to show the migration of resources between internal and external reporting categories during the field life cycle.

The reduction in uncertainty based on performance should be adequately reflected in the annual reserve and scope for recovery estimates for the field.

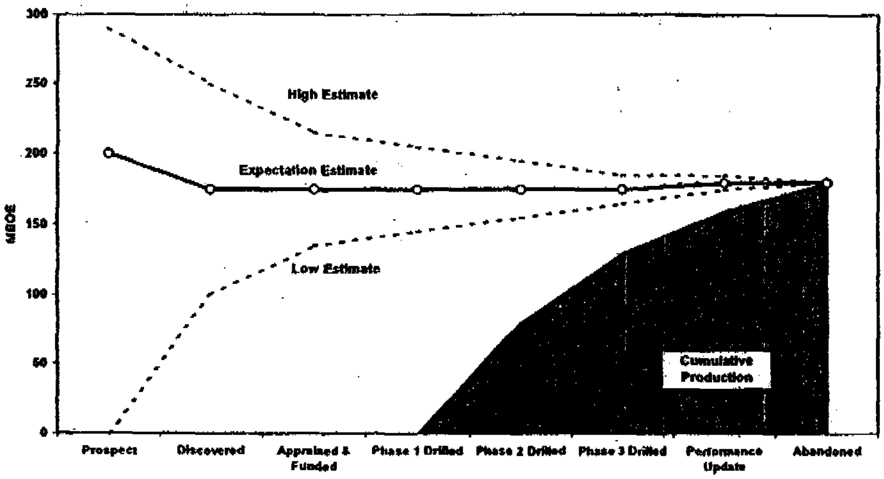

Figure A4.2: Uncertainty Reduction during the Field Life Cycle

A4.3.2 Addition of Proved Reserves Volumes

Proved Reserves volumes are added together at various levels (reservoirs, fields, areas etc) during the resource assessment and reporting process. When Proved reserves are based on P85 or Low estimates, such addition could 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 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** (see Section 6.1). 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 is comprised 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).

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

APPENDIX 5 SEC RESERVES AUDITS - TERMS OF REFERENCE

The purpose of the Proved Reserves Audit is to verify that appropriate processes are in place in the OU to ensure that the Proved and Proved Developed reserves estimates for external (SEC) reporting are compliant with (these) 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.
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 audit will be carried out by reviewing the reserves estimation and submission process through interviews of OU staff and by taking at random a number of fields for detailed analysis.

The frequency of the audit will in principle be once every four years for each OU, but should be adjusted as warranted by size of OU, 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 OU/NVO 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 OU premises and will be based on documentation available in the OU. Assistance of OU staff may be called upon.

An audit report will be submitted to the Managing Director of the OU, to the EP CEO and EP RBA, to the OUs Hydrocarbon Resource Manager 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 OU comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 6 TERMINOLOGY

A6.1 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 / sedimentary units until production performance proves communication to exist across faults/ 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.

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

The 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 fiscalised 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 fiscalised 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).

Ultimate Recovery

The ultimate recovery (UR) of a hydrocarbon field is the sum of cumulative production and the estimated volume of reserves (developed + undeveloped).

Total Resource Volume

The Total Resource Volume of a hydrocarbon field is the sum of cumulative production, the estimated volume of reserves (developed + undeveloped) and the Total Scope for Recovery.

A6.2 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, divided by the width of that interval.

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 that it will be exceeded by the stochastic variable.

P15

The value that has a 15% probability that it will be exceeded by the stochastic variable.

Mean

The statistical mean of a stochastic variable is the probability weighted average of the variable over the entire variable range.

Mean Success Volume (MSV)

The probability weighted average of all realisations that equal or exceed the minimum reserves required for a commercial development of the resource.

Probability of Success (POS)

The probability that the minimum commercial volume will be exceeded and which therefore indicates the likelihood of any future development. The product of MSV and POS is the recovery expectation.

A6.3 Commercial Terminology

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 annual 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.

A6.4 Exploration versus 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 4). 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.

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Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

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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

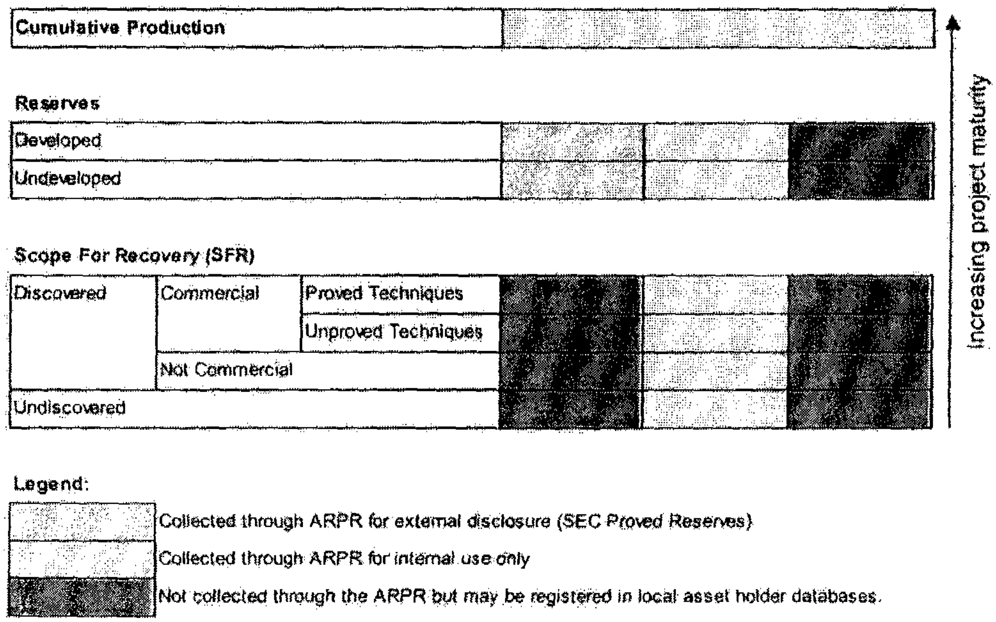

Figure 1: Overview of Shell Petroleum Resource Classification System

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:

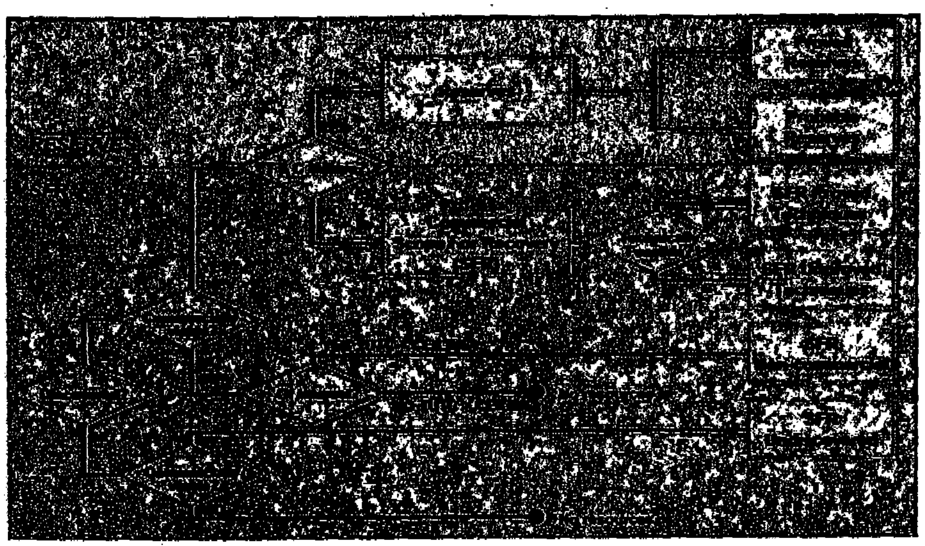

Figure 2: Resource classification guide

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).

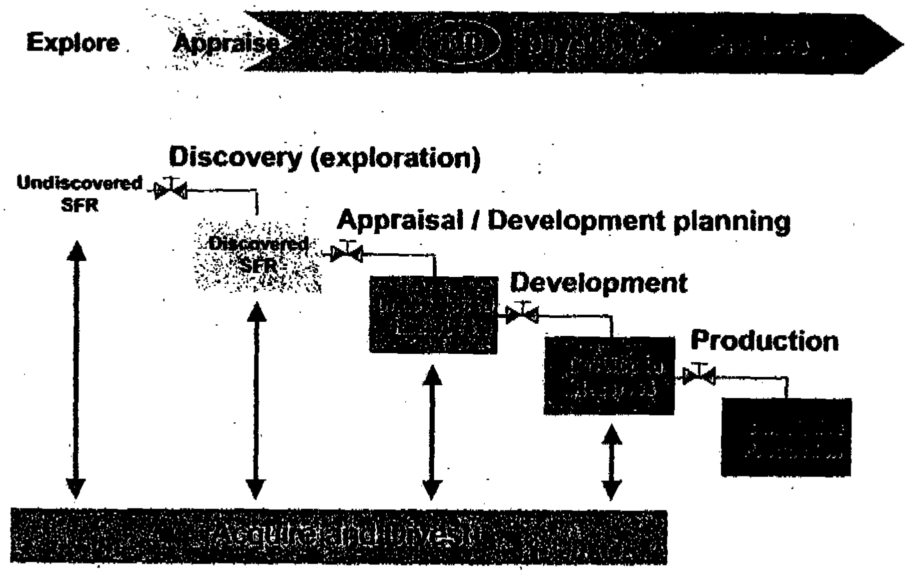

Figure 3: Resource classification flow diagram

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.