11 March 2011
NSX Announcement

EXPLORATION UPDATE AND INDEPENDENT REVISION TO POTENTIAL RESOURCES

African Petroleum Corporation Limited (**NSX: AOQ**) ("African Petroleum" or the "Company") which holds 100% of offshore Liberian Blocks LB-08 and LB-09, located South East of the recent oil discoveries made in Sierra Leone, is pleased to provide the following update.

African Petroleum has undertaken an initial evaluation of the 5,100 sq km of 3D seismic data over Blocks LB-08 and LB-09 and has identified more than 50 prospective intervals in over 40 prospects and leads, some of which are similar to the recent Anadarko Petroleum Corporation's ("Anadarko") Mercury-1 discovery in nearby Sierra Leone and the large Jubilee field discoveries in Ghana by Tullow Oil plc.

African Petroleum's 2011 two well deepwater offshore drilling programme in West Africa, using the Maersk Deliverer, is on track to commence its first well in Block LB-09 in May 2011. The first well will drill a well-defined structure with potential for multiple reservoirs and source rocks, including geological units, reported by Anadarko to have been oil bearing in its recent Mercury-1 discovery, in nearby Sierra Leone.

A detailed assessment of the Company's prospective resources at LB-08 and LB-09 has been carried out by independent specialist advisors, ERC Equipoise Limited ("ERCE") to industry standard classification and reporting. ERCE is an industry leader in resource assessment with significant West African experience.

ERCE has independently evaluated 21 prospective reservoir layers in eight of the most technically progressed prospect clusters out of the identified prospects at LB-08 and LB-09. ERCE estimates the best (P50), unrisked resources at approximately 1.4 billion stock tank barrels ("stb") with an upside potential (P10), unrisked resource of approximately 5.3 billion stb. Additionally, the mean unrisked resources are estimated at approximately 2.4 billion stb. A summary of the unrisked prospective resources at LB-08 and LB-09 contained in ERCE's report dated 8 March 2011 (ERCE Report) is set out in Table 1. Analysis is ongoing to appraise the additional prospects and shareholders will be kept informed of any further potential resource updates.

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Table 1
Summary of Unrisked Prospective Resources at LB-08 and LB-09[1]

Block	Low (MM stb)	Best (MM stb)	High (MM stb)	Mean (MM stb)
LB-08	64	263	1112	499
LB-09	299	1135	4155	1894
Total	363	1398	5267	2393

Note: Unrisked Prospective Resources sourced from ERCE's Report.
MM means millions.

ERCE's full report is attached to this announcement.

Commenting, Karl Thompson African Petroleum's Chief Executive Officer said, "I am pleased with the significant progress the Company is making with its exploration programme in Liberia and delighted with the ERC Equipoise's endorsement of the Liberian Blocks' potential. We are looking forward to the next important stage in the Company's development with the drilling of our first well in Block LB-09 in May 2011."

Yours faithfully
African Petroleum Corporation Limited

Tony Sage
Non-Executive Deputy Chairman

[1] **It should be noted that the potential resources are all seismic features which have not been penetrated by any wells. It should be clearly understood that the potential resources are undiscovered and the project is an exploration play. There is no certainty that any portion of the undiscovered resources will be discovered and that, if discovered, may not be economically viable or technically feasible to produce from any discovered resources.**

8 March 2011

The Directors
African Petroleum Corporation Ltd
12 St. James's Square
London
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Attention: Mr Karl Thompson

Dear Sirs

Re: Review of Prospective Resources for African Petroleum Corporation Ltd

In response to your request, we have reviewed the prospectivity of the petroleum exploration interests of African Petroleum Corporation Limited and its associated companies ("APC"), in Blocks 8 & 9 offshore Liberia and we have prepared estimates as of 28 February 2011 of the prospective petroleum resources.

We have carried out this work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1.

This report is for the sole use of APC and financial advisors. It may not be disclosed to any other person or used for any other purpose without the prior written approval of a director of ERC Equipoise Ltd ("ERCE").

Introduction

African Petroleum Corporation Limited holds a 100 per cent contractor interest in a Production Sharing Contract ("PSC") covering Blocks 8 & 9 offshore Liberia, and has identified over 50 prospective intervals within the licence areas. ERCE has independently assessed 21 of these prospective reservoir layers which aggregate to eight prospect clusters (Figure 1). Our independent Best Estimate (P50) of prospective oil resources for the prospects we have assessed is 1398 MMstb unrisked, or 196 MMstb risked. Additionally, our independent Mean estimate of prospective oil resources for the prospects is 2393 MMstb unrisked or 335 MMstb risked.

The first exploration period in each block extends through to 11 June 2012. The commitments, during the first period, are identical and for each block comprise three components

a) Acquire 1,500 km^2 of 3D seismic data
b) Drill one exploration well to a minimum depth of 2000 metres
c) Conduct geological and geophysical studies

Thus far components (a) and (c) have been satisfied with the acquisition in 2010 of 5170 km^2 of 3D seismic data and a full programme of geological and geophysical studies. It is intended that two wells be drilled in 2011. The minimum financial commitments of the first period have also been satisfied.

For each block, there are two further optional (but automatic) exploration periods of two years each that can be entered into with a further well (to a minimum of 2000 metres) being required in each block in each period. Furthermore relinquishment of 25 per cent of the licence area is required at the end of the first and second exploration periods while at the end of the third period all areas not retained for appraisal and development are to be relinquished. There are also provisions for appraisal periods and exploitation period of 25 years (with an additional term of 10 years if necessary) for each development area.

In carrying out our evaluation of the interests, we have relied upon information provided by APC which comprised details of APC's licence interests, offset well data and associated analysis, seismic data including interpretation, basic exploration data, technical reports and volumetric estimates, where appropriate.

Our approach has been to commence our investigations with the most recent technical reports and interpreted data. From these we have been able to identify those items of basic data which require re-assessment. Where only basic data have been available or where previous interpretations of data have been considered incomplete, we have undertaken our own interpretation. A site visit was not undertaken.

In estimating petroleum in place and recoverable, we have used the standard techniques of prospect analysis. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty and have used statistical methods to calculate the range of petroleum initially in place and recoverable.

We have estimated the chance of success for drilling the identified exploration prospects, using the industry standard approach of assessing the likelihood of source rock, charge, reservoir trap and seal. The result is the chance or probability of discovering hydrocarbons in sufficient quantity and which test at a sufficient rate to permit consideration for subsequent appraisal and development.

The nomenclature used in this report is presented in Appendix 2.

Summary of Results

Block 8 comprises 3621 km^2, and Block 9 comprises 3514 km^2. Water depths range from less than 100 m to over 3000 m. Around two thirds of the blocks lie in water depths greater than 500 m.

The deeper water area of both blocks is covered by regional 2D seismic data and a recent 3D seismic survey, the latter acquired by APC in 2010. The 3D seismic survey covers approximately 5,170 km^2. Although no deep water wells have been drilled on the blocks, two wells have been drilled on the shelfal areas, Wells Cestos-1 and S/3-1. Well S/3-1 provides a well to seismic tie and enables us to extrapolate stratigraphy into the deeper water areas, although there is uncertainty in the stratigraphic age of the identified reflectors. This well also has oil shows in Late Cretaceous sandstones.

APC has identified both structural and stratigraphic traps within the 3D area, a number of which have been matured to prospect status. Of the 50 identified prospective layers, APC has around 30 prospective intervals identified (leads) that are being matured to prospect status, over and above those we have reviewed. Area of closure of the leads and prospects identified by APC varies from 1.3 to 187 km^2.

Reservoir intervals are identified at several stratigraphic levels from the pre-rift Albian (Lower Cretaceous), through the post rift of the Upper Cretaceous (Turonian/Cenomanian and Campanian/Maastrichtian) and early Tertiary. Many of the identified traps have multiple stratigraphic targets. Regionally, hydrocarbons have been discovered in the intervals identified by APC. There is seismic evidence for the presence of stratigraphic intervals that may contain reservoir rock and also seals in all but the pre-rift section.

We have made independent estimates of resources and geological chance of success (COS) for a number of prospects identified by APC, where we identify 21 prospective layers in total. Volumes have been computed solely for oil. However, there is uncertainty in the geological information available, and it is therefore possible that a gas charge could have occurred. Our estimates of total unrisked and risked prospective resource by reservoir attributable to APC for all the prospects we have reviewed are presented in Table 1 below.

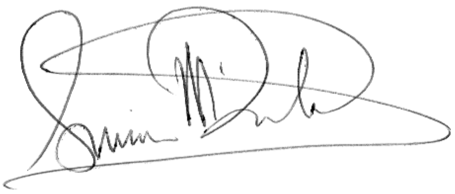
We have used Play and Prospect risk to assign COS to each of the prospective intervals, to reflect the fact that although there is seismic evidence for the presence of both reservoir and seal rocks, there is some uncertainty in the presence and/or maturity of source rock intervals. A successful well on a given prospect may remove the Play risk, should the well prove reservoir, charge and source in a given play. This will have the effect of de-risking further prospects associated with that play. Some of the identified prospective intervals, (four in total, within the Tertiary), are quite shallow to mud line, and may also be subject to a risk of biodegradation of any oil charge. This has been factored into our evaluation.

Professional Qualifications

ERC Equipoise is an independent consultancy specialising in petroleum reservoir evaluation. Except for the provision of professional services on a fee basis, ERC Equipoise has no commercial arrangement with any other person or company involved in the interests that are the subject of this report.

The work has been supervised by Mr Simon McDonald, a Chartered Petroleum Engineer and a member of the Energy Institute, the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. He has over 34 years experience in the evaluation of oil and gas fields and acreage, preparation of development plans and assessment of reserves and resources.

Yours faithfully
ERC Equipoise Limited



Simon McDonald
Engineering Director

African Petroleum Corporation - Liberia Summary

Table 1

Liberia Blocks 8 and 9

STOIIP and Prospective Oil Resources

	Prospect	Reservoir	STOIIP				Unrisked Prospective Resource				Prospect Risk	Play Risk*	COS	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	(%)	(%)	(%)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
8_1 Horst Cluster	APC8-1 Pg20-10	Paleogene 4 way dip trap	15	69	326	146	3	18	91	40	16	32	5	0.2	0.9	4.7	2.1
	APC8-1 Horst UK90-70	Maastrichtian 4 way dip trap	19	104	579	256	6	37	213	96	26	57	15	0.9	5.6	31.9	14.4
	APC8-1 UK60 Channel	Campanian to Turonian stratigraphic trap	34	122	439	200	13	46	163	75	13	57	8	1.0	3.5	12.5	5.7
	APC8-1 Syn-rift	Albian 4 way dip trap	38	158	679	302	14	59	255	113	18	39	7	1.0	4.2	18.0	8.0
	Sub-Total		106	453	2023	905	36	160	722	324				3.1	14.2	67.0	30.1

	Prospect	Reservoir	STOIIP				Unrisked Prospective Resource				Prospect Risk	Play Risk*	COS	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	(%)	(%)	(%)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
8_2 North	APC8-2 North Pg20-10	Paleogene 4 way dip trap	75	228	671	326	17	59	197	90	19	32	6	1.0	3.6	12.1	5.5
	APC8-2 North UK70	Maastrichtian 4 way dip trap	15	64	280	122	6	24	107	46	23	57	13	0.7	3.1	13.7	5.9
	APC8-2 North UK60	Campanian to Turonian 4 way dip trap	14	54	227	102	5	20	86	39	24	57	13	0.7	2.7	11.5	5.1
	Sub-Total		104	346	1177	550	27	103	390	174				2.4	9.4	37.3	16.5

	Prospect	Reservoir	STOIIP				Unrisked Prospective Resource				Prospect Risk	Play Risk*	COS	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	(%)	(%)	(%)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
9_1 Apalis Cluster	APC_9_1 Pg20	Paleogene 4 way dip trap	7	15	34	19	2	4	10	5	14	32	5	0.1	0.2	0.4	0.2
	APC_9_1 Pg10	Paleogene 4 way dip trap	11	27	66	34	4	10	25	13	24	32	8	0.3	0.8	1.9	1.0
	APC_9_1 UK90	Maastrichtian 4 way dip trap	16	55	191	88	6	20	72	33	35	57	20	1.1	4.1	14.4	6.6
	APC_9_1 UK75	Maastrichtian 4 way dip trap	14	65	288	128	5	24	107	48	35	57	20	1.0	4.9	21.4	9.6
	APC_9_1 UK72	Maastrichtian 4 way dip trap	43	149	542	248	15	55	203	93	35	57	20	3.1	11.0	40.6	18.5
	APC_9_1 UK70	Maastrichtian 4 way dip trap	19	93	453	200	7	34	169	75	35	57	20	1.4	6.8	33.9	15.0
	APC_9_1 UK60	Campanian to Turonian 4 way dip trap	15	67	306	135	5	25	115	50	31	57	18	1.0	4.5	20.5	8.9
	APC_9_1 UK50	Campanian to Turonian 4 way dip trap	5	16	46	22	2	6	17	8	24	57	13	0.2	0.8	2.3	1.1
	APC-9_1 Synrift MCU	Albian 4 way dip trap	29	121	495	221	10	45	186	83	18	39	7	0.7	3.2	13.1	5.9
	APC9-2 UK60-70	Campanian to Turonian stratigraphic trap	32	167	737	331	12	63	280	124	15	57	9	1.0	5.4	24.0	10.6
	Sub-Total		191	775	3158	1426	68	286	1185	532				9.9	41.5	172.6	77.5

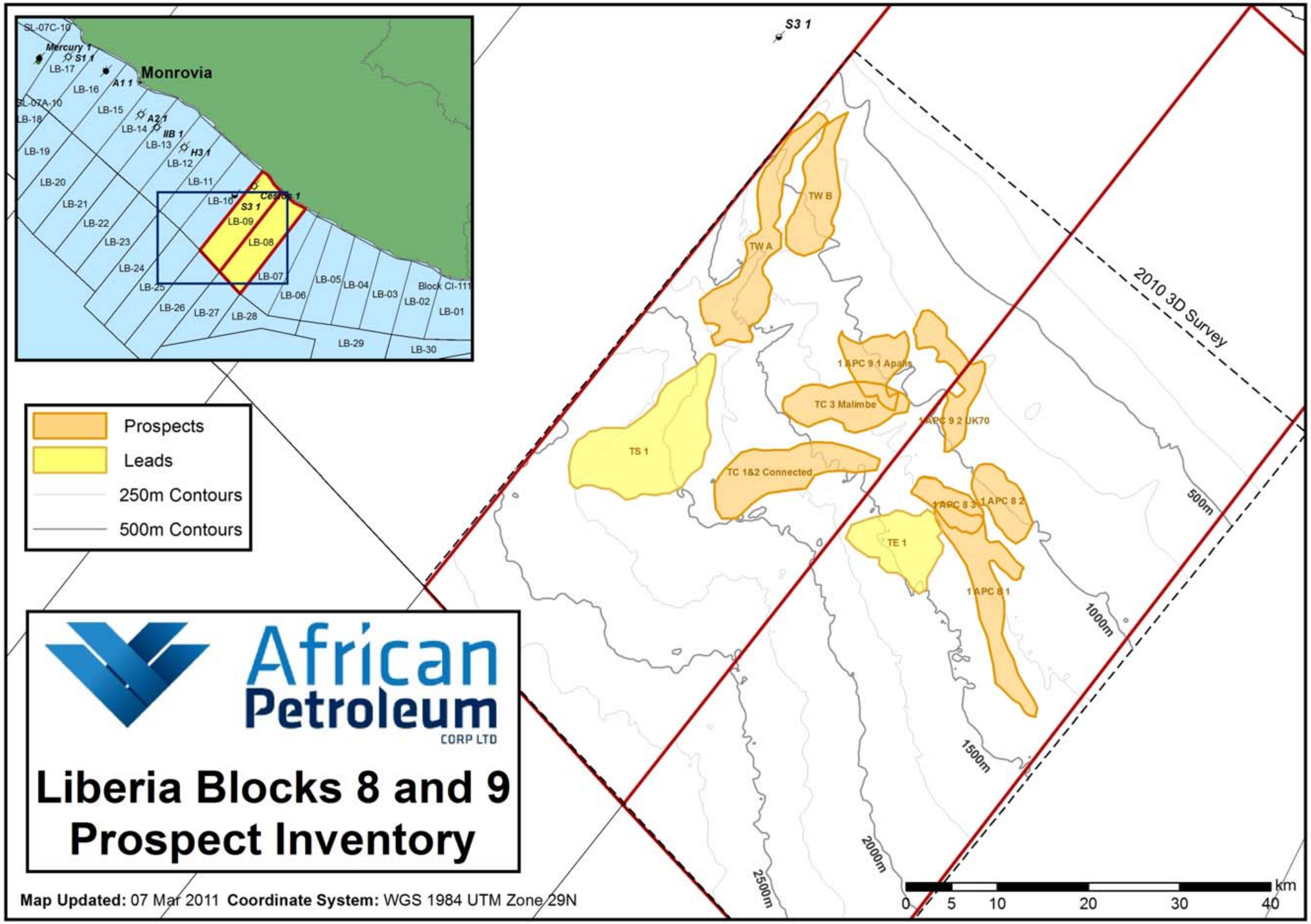
	Prospect	Reservoir	STOIIP				Unrisked Prospective Resource				Prospect Risk	Play Risk*	COS	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	(%)	(%)	(%)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
Central Fan Cluster	TC 3Malimbe	Campanian to Turonian Stratigraphic trap	125	446	1536	698	46	165	577	262	27	57	16	7.2	25.7	89.8	40.7
	Turonian Central_Connected	Campanian to Turonian Stratigraphic trap	186	676	2281	1054	67	250	856	395	31	57	18	11.8	43.8	149.7	69.1
	Sub-Total		311	1122	3817	1752	113	415	1433	657				19.0	69.4	239.5	109.8

	Prospect	Reservoir	STOIIP				Unrisked Prospective Resource				Prospect Risk	Play Risk*	COS	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	(%)	(%)	(%)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
Western Fan Cluster	Turonian West Lower Prelim	Campanian to Turonian Stratigraphic trap	117	335	900	445	43	125	339	167	20	57	11	4.8	13.8	37.7	18.6
	Turonian West Upper	Campanian to Turonian Stratigraphic trap	205	828	3178	1441	75	310	1198	539	27	57	15	11.4	47.2	182.6	82.1
	Sub-Total		322	1163	4078	1886	118	434	1537	706				16.2	61.1	220.3	100.7

Block	STOIIP				Unrisked Prospective Resource				Net Risked Prospective Resource			
	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
8	210	799	3200	1455	64	263	1112	499	5	24	104	47
9	824	3060	11053	5064	299	1135	4155	1894	45	172	632	288
Total	1034	3860	14253	6519	363	1398	5267	2393	50	196	737	335

* Play risk: relfects the risk to the primary components of a petroleum system being absent for each identified play fairway (here, stratigraphic interval). A successful well pn a given prospect may remove the Play risk, should the well prove reservoir, charge and source in a given play.

Figure 1: Summary of leads and prospects, Blocks 8 & 9 (after APC)



Appendix 1

SPE/WPC/AAPG/SPEE Petroleum Reserves and Resources Classification System and Definitions

The Petroleum Resources Management System

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources managements system provides a consistent approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that the SPE-PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, hereinafter referred to as the SPE-PRMS can be viewed at www.spe.org/specma/binary/files6859916Petroleum_Resources_Management_System_2007.pdf.

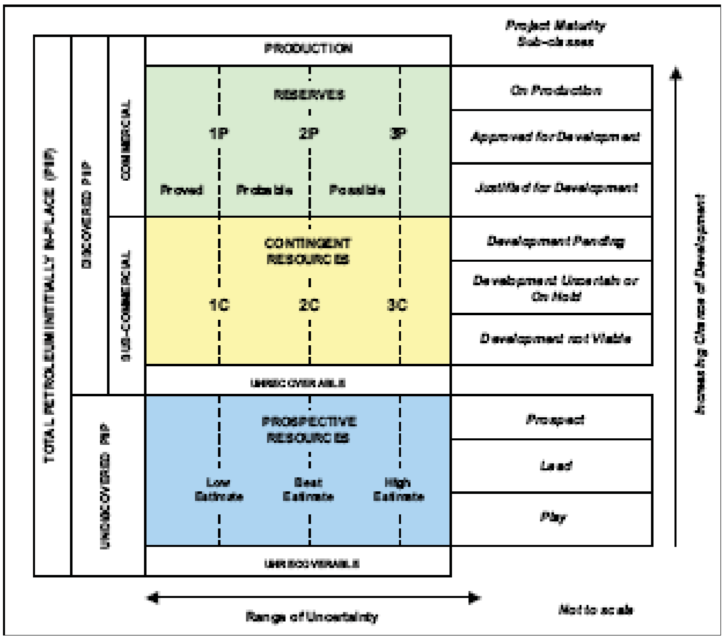
Overview and Summary of Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.



The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Development", that is, the chance that the project that will be developed and reach commercial producing status.

The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE

Total Petroleum Initially in Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations.

It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE

Discovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

1) the area delineated by drilling and defined by fluid contacts, if any, and
2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see “2001 Supplemental Guidelines,” Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that

1) the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and
2) interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE

Undiscovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play
A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see “2001 Supplemental Guidelines,” Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project.

Appendix 2

Nomenclature

"AvO"	means amplitude versus offset
"bbl"	means barrel, 42 US Gallons
"bcf"	means billions of cubic feet
"Bo"	means formation volume factor of oil
"COS"	means chance of success
"FVF"	means formation volume factor
"km^2"	means square kilometres
"m"	means metre
"MM"	means millions
"ms"	means milliseconds
"Phi"	means porosity
"PSC"	means Production Sharing Contract
"P90" or "Low"	means 90 per cent confidence level
"P50" or "Best"	means 50 per cent confidence level
"P10" or "High"	means 10 per cent confidence level
"rb"	means reservoir barrels
"rcf"	means cubic feet at reservoir conditions
"Rec Res."	means recoverable resource
"Rf" or "RF"	means recovery factor
"s"	means second
"scf"	means standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"So"	means oil saturation
"ss"	means subsea
"stb"	means stock tank barrels
"STOIIP"	means stock tank oil initially in place
"US $"	means United States dollars