Audit of Reserves and Contingent Resources

PA Resources AB ("PA Resources", the "Company") publishes the third party review of Reserves and Contingent Resources as of 30 June 2014 undertaken by independent audit firm ERCE Equipoise ("ERCE"), and the Company's management commentary on the report. Highlights of this review are:

- PA Resources has, as of 30 June 2014, net working interest oil and condensate 1P Reserves of 4.5 mmbbl, 2P Reserves of 6.8 mmbbl, and 2C Contingent Resources of 60 mmboe of liquid and gas hydrocarbons
- ERCE estimates, at 1 January 2015, unrisked 2P Reserves NPV10 to be USD 112 million and unrisked 2C Contingent Resources to be USD 471 million, totalling USD 583 million for the Company's core assets
- The outcome of PA Resources' first comprehensive independent report of Reserves and Contingent Resources has largely confirmed the Company's estimates of recoverable volumes from its main production, appraisal and development assets
- The final report is closely in line with the preliminary Reserves, Contingent Resources and Net Present Value numbers released on 18 September, 2014
- The key variations from reported Reserves and Contingent Resources as per 31 December 2013 are the re-categorisation of the Zarat field liquids from Reserves to Contingent Resources as the field development is being revised, and the exclusion of Contingent Resources in several small discoveries in the North Sea and Africa pending greater clarity on their commercial development potential.

Background

ERCE was instructed to conduct an independent third party review of the Company's Reserves and Contingent Resources as of 30 June 2014. PA Resources' reserve reports have historically been based on a combination of internal, operator and third party estimates. As such, this review by ERCE is the Company's first comprehensive independent audit of its assets.

Classification and reporting are according to the 2007 standard SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS). The focus of the review has been on the key assets that are considered to make up the core producing and discovered asset base of the Company, and as such Prospective Resources were excluded from the audit scope. Per PA Resources' request, ERCE has performed an economic valuation of the audited Reserves and Contingent Resources. ERCE has summarised its work in two letters presenting the results from the Reserves and Contingent Resources audit and the valuation respectively which are attached to this document.

Reserves and Contingent Resources as of 30 June 2014

ERCE attributes working interest oil Reserves to PA Resources in the Didon, Douleb and Tamesmida fields in Tunisia, and the Aseng and Alen fields in Equatorial Guinea, as presented in Table 1. In the light of PA Resources' small interest in the Alen field, ERCE has not determined the remaining Reserves; the estimates presented herein are those advised by the Company.

PA Resources has Contingent Resources in Tunisia, Equatorial Guinea and Denmark. Contingent Resources are made up of oil, condensate, gas and LPG. Table 2 and Table 3 show the liquid and the gas component of Contingent Resources respectively. Table 4 shows Contingent Resources converted to million barrels of oil equivalent of hydrocarbons.

ERCE has presented Contingent Gas Resources as gross raw gas including inert content. Given the high inert content of some of PA Resources discoveries (primarily in Tunisia), the Company wishes to provide an indication of the gas resources which are likely to be available for commercialisation after reduction of inert content to known or anticipated sales specification. These resources comprise 'Sales Gas' as assessed by ERCE in their valuation with an economic cut-off applied plus estimated fuel gas which are collectively described by PA Resources as 'Contingent Resources excluding inerts'. In the light of PA Resources' small interest in the Alen field, ERCE has not determined the gross field Contingent gas Resources; the estimates presented herein are those advised by the Company which are the operator's latest estimates, following allowance for the removal of inerts, fuel and shrinkage.

Final gas volumes differs slightly from the ones released on 18 September due to updates relating to inert gas content for Block I and LPG volumes conversion for Zarat and Elyssa.

Table 1: Working Interest Reserves as of 30 June 2014

Field (Million barrels)	**Net PA Oil Economic Reserves**		
	1P	2P	3P
Aseng	2.91	4.43	5.62
Alen	0.14	0.14	0.14
Didon[1]	0.28	0.43	0.46
Douleb / Tamesmida	1.19	1.76	2.17
Reserves at 30 June 2014	**4.53**	**6.76**	**8.39**

1. After completion of EnQuest farm-in

Table 2: Contingent Oil and Condensate Resources as of 30 June 2014

Field (Million barrels)	**Net PA Contingent Resources – Liquids**		
	1C	2C	3C
Aseng	0.9	0.9	1.0
Diega	1.5	2.9	5.5
Zarat[2, 3]	7.5	10.9	22.7
Didon[2]	0.8	1.2	1.8
Didon North[2, 3]	0.4	0.8	1.8
Elyssa[2, 3]	1.0	1.7	2.9
El Nisr[2, 3]	0.3	0.4	0.5
DST	0.6	0.9	1.2
Little John	3.3	5.9	10.6
Broder Tuck	0.9	1.2	1.8
Contingent Oil and Condensate Resources	**17.1**	**26.6**	**49.8**

1. Volumes presented above are the sum of the oil and condensate volumes shown respectively in tables 5 and 6 of ERCE letter "Audit of Reserves and Certain Contingent Resources"
2. After completion of EnQuest farm-in
3. No provision for ETAP back-in, which can be up to 55%

Table 3: Contingent Gas Resources excluding inerts as of 30 June 2014

Field (Billion Standard Cubic Feet)	**Net PA Contingent Resources - Gas**		
	1C	2C	3C
Block I: Aseng, Diega, Yolanda, Alen	39	52	80
Zarat[4, 5]	32	49	75
Elyssa[4, 5]	41	67	109
El Nisr[4, 5]	5	8	11
Little John	1	2	4
Broder Tuck	18	25	33
Contingent Gas Resources excluding inerts	**137**	**203**	**311**

1. Volumes presented above are derived from Table 4 in ERCE letter "Valuation of Reserves and Certain Contingent Resources"
2. Contingent Resources excluding inerts have been calculated as sales gas with an economic cut-off applied plus hydrocarbon gas used for fuel. Fuel gas is generally minimal with the exception of Zarat where fuel gas accounts for 6% of total raw gas
3. LPG volumes shown in Tables 8 in ERCE letter "Audit of Reserves and Certain Contingent Resources" have been added to the volumes above converted to bcf utilising a conversion factor of 1.67 x 10-5 tonnes/bcf
4. After completion of EnQuest farm-in
5. No provision for ETAP back-in, which can be up to 55%

Table 4: Contingent Resources – total liquid and gas resources excluding inerts as of 30 June 2014

Field (Million barrels of oil equivalent)	**Net PA Contingent Resources - Total**		
	1C	2C	3C
Aseng – Liquids	0.9	0.9	1.0
Diega – Liquids	1.5	2.9	5.5
Block I: Aseng, Diega, Yolanda, Alen – gas	6.5	8.6	13.3
Zarat[2, 3]	12.9	19.2	35.2
Didon[2]	0.8	1.2	1.8
Didon North[2, 3]	0.4	0.8	1.8
Elyssa[2, 3]	7.9	12.8	21.1
El Nisr[2, 3]	1.1	1.6	2.4
DST	0.6	0.9	1.2
Little John	3.4	6.2	11.2
Broder Tuck	3.9	5.4	7.2
Contingent Resources – Total	**39.9**	**60.4**	**101.6**

1. Utilises energy equivalency of 6,000 cubic feet of gas per barrel of oil equivalent
2. After completion of EnQuest farm-in
3. No provision for ETAP back-in, which can be up to 55%

Changes from Reserves and Contingent Resources at 31 December 2013

PA Resources presents in Table 5 (below) a reconciliation between Reserves and Contingent Resources at 31 December 2013 and the equivalent categories at 30 June 2014. Note that PA Resources has habitually reported Contingent Resources for gas excluding inerts as explained above, and this practise is maintained in this reconciliation.

1P and 2P Reserves were revised downwards to 4.5 mmbbl and 6.8 mmbbl respectively, primarily due to the re-categorisation of the Zarat field liquids from Reserves to Contingent Resources, reflecting the ongoing revision of the field development plan to be submitted for regulatory approval later in 2014. Excluding the Zarat field, 1P reserves have increased by 0.3 mmbbl due to the implementation of a programme of Electrical Submersible Pump (ESP) installations in Didon and an upward revision to the proven reserves of the Aseng field. The Aseng field is for the first time deemed to have sufficient production history to adequately forecast future production performance. This change of approach had led to a small reduction in Aseng 2P Reserves. A delay to a planned infill well on the Didon field has led to a re-categorisation of the relevant volumes from Reserves to Contingent Resources. Together with the change in the Aseng field Reserves this re-categorisation has led to an overall reduction in 2P Reserves of 1 mmbbl. 3P Reserves, which have not previously been presented by the Company, provide an upper estimate.

Contingent Resources have been revised upwards by 0.6 mmboe at 2C level, being the net effect of the re-categorisation of the Zarat field liquids from Reserves to Contingent Resources and a number of negative revisions. A notable revision is the exclusion of several small discoveries in the North Sea and Africa pending greater clarity on their commercial development potential. Other revisions relate to Block I, Elyssa and a number of smaller changes to various assets.

In line with PRMS it is anticipated that Contingent Resources will be converted to Reserves on regulatory approval of development plans, supporting joint venture and third party agreements such as unit operating agreements, and gas sales contracts where these are needed to sanction development.

Table 5: Changes from Reserves and Contingent Resources at 31 December 2013

Company Working Interest	**Reserves**			**Contingent Resources**		
(Million barrels of oil equivalent)	1P	2P	3P	1C	2C	3C
Reserves/Contingent Resources[1] as 31 Dec. 2013	**14.1**	**21.6**	**-**	**-**	**59.8**	**-**
Production (6 months)	-0.6	-0.6	-	-	-	-
Revision: Zarat	-9.3	-13.2	-	-	12.4	-
Revision: Small discoveries excluded from audit	-	-	-	-	-3.3	-
Revision: Others	0.3	-1.0	-	-	-8.4	-
Reserves/Contingent Resources[1] as 30 June 2014	**4.5**	**6.8**	**8.4**	**39.9**	**60.4**	**101.6**

1. Contingent gas resources excluding inerts

Valuation

ERCE has performed an economic valuation of PA Resources' Reserves and Contingent Resources with a valuation date of 1 January 2015, after allowing for estimated production from 30 June to 31 December 2014. Table 6 presents the results of this valuation, excluding Didon North and El Nisr. In this process, and in addition to auditing volume and production profiles, ERCE has also reviewed the development plans, appraisal and development costs and project timings of PA Resources' assets as well as the applicable fiscal terms and fiscal models, to ensure that the economic valuations reflect reasonable assumptions. The development scenarios are subject to change as the assets are progressed. Economic valuations have not been discounted to reflect risk and uncertainty in timing, cost or resource levels and no oil or gas price sensitivities have been applied. However, where PA Resources is the recipient of certain carries under sale and purchase agreements with EnQuest (Zarat and Elyssa fields) and Dana (Lille John and Broder Tuck fields) these are reflected in economic assessments. Price scenarios and other assumptions are documented in Appendix 2.

Table 6: Company Core Valuation – as at 1 January 2015

Field (Million US Dollars)	**Valuation**		
Reserves	**1P**	**2P**	**3P**
Block I (Aseng + Alen)	83	108	128
Didon	-16	-10	-8
DST	9	14	19
Sub-total Reserves	76	112	139
Contingent Resources[4] – Core Values	**1C**	**2C**	**3C**
Block I – Additional Liquids (Aseng + Diega)	24	48	65
Block I – Additional Gas (Aseng + Alen + Diega +Yolanda)[3]	21	30	39
Zarat[2]	91	158	211
Elyssa[2]	24	54	94
Didon	11	25	48
DST	4	7	11
Broder Tuck	41	53	81
Lille John	59	95	182
Sub-total Contingent Resources[4]	274	471	731
TOTAL UNRISKED VALUATION	**350**	**583**	**870**

1. Didon North and El Nisr are not included in the Company core valuation
2. Assumed a 50% ETAP back-in. For Zarat, valuation of the 2C estimate of Contingent Resources is USD 310 million with no ETAP back-in and USD 143 million with a 55% ETAP back-in. For Elyssa these are USD 97 million and USD 50 million, respectively
3. Valuation changed versus numbers released on 18 September 2014 due to inert assumptions relating to Block I
4. Contingent Resources excluding inerts for applicable gas accumulations

30 September 2014

The Directors
PA Resources AB
Kungsgatan 44, 3rd Floor
SE-111 35 Stockholm
Sweden

Dear Sirs

Re: Audit of Reserves and Certain Contingent Resources, PA Resources AB

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has reviewed the Reserves and certain Contingent Resources held by PA Resources AB and its subsidiaries ("PA") within its Equatorial Guinean, Tunisian and Danish properties. We have used information and data available and reasonable forward-looking expectations up to or before 30 June 2014.

We have carried out this work using the 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. Nomenclature used in this letter is summarised in Appendix 2.

This letter is for the sole use of PA and its 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 ERCE. ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees. In the case that material is delivered in digital format, ERCE does not accept any responsibility for edits carried out after the product has left the Company's premises.

This letter has been issued in advance of our final report to PA.

Introduction

PA holds varying equity interests in exploration licences and permits and production concessions offshore Denmark, offshore Equatorial Guinea and onshore and offshore Tunisia. A summary of the properties reviewed is presented in Table 1.

Table 1: Properties reviewed

Country	Licence/Permit/Concession	PA Interest (%)	Field or Discovery	Expiry of Current Phase	Remaining Work Commitments in this Phase	Notes
Equatorial Guinea	Block I	0.285%	Alen	Jan. 2036	None	Unitized interest.
	Block I	5.70%	Aseng	Jun. 2034	None	
	Block I	4.28%	Diega	Jun. 2034	None	Not yet unitized. PA interest is estimated.
	Block I	5.70%	Yolanda	Jun. 2034	None	
Tunisia	Didon concession	30.00%	Didon	Dec. 2027	None	After completion of EnQuest farm-in.
	Zarat: concession pending	15.00%	Zarat	N/A	N/A	Not yet unitized. PA interest estimated using current agreed cost split.After completion of EnQuest farm-in.
	Zarat permit	30.00%	Elyssa	Jul. 2015	2 wells	After completion of EnQuest farm-in.
	Zarat permit	30.00%	Didon North	Jul. 2015		After completion of EnQuest farm-in.
	Zarat permit	23.40%	El Nisr	Jul. 2015		Not yet unitized. PA interest estimated. After completion of EnQuest Farm-in.
	Douleb concession	70.00%	Douleb	Dec. 2035	1 well	
	Semmama concession	70.00%	Semmama	Dec. 2025	None	
	Tamesmida concession	95.00%	Tamesmida	Dec. 2035	None	
Denmark	Licence 12/06	24.00%	Broder Tuck	May 2016	None	After Dana Farm-in.
	Licence 12/06	24.00%	Lille John	May 2016	1 well	After Dana Farm-in.

ERCE has determined the remaining oil and condensate Reserves of the Aseng field, Block I, Equatorial Guinea, the Didon field, Didon Production Concession, offshore Tunisia, and the Douleb and Tamesmida fields within the Douleb and Tamesmida Production Concessions, onshore Tunisia, as at 30th June 2014. PA has a unitised 0.285% working interest in the Alen field, which extends partially into Block I. Block I has yet to lift its entitlement of Alen production owing to delays in government execution of the Alen unitisation agreement. In the light of PA's small interest in the Alen field, ERCE has not determined the remaining Reserves; the estimates presented herein are those advised by PA.

ERCE has calculated Contingent oil, gas, condensate and LPG Resources in the Aseng field, Block I, the Zarat, Elyssa, El Nisr and Didon North discoveries within the Zarat Exploration Permit, (the Zarat Production Concession is still awaiting government ratification), and, due to additional activity that PA is planning, within the Didon, Doualeb and Semmama fields, offshore and onshore Tunisia. The Tamesmida field is currently shut in, pending the resolution of security issues. ERCE has assigned Contingent oil Resources to this field, pending the resolution of these issues.

ERCE has also calculated Contingent oil, gas and condensate Resources in the Lille John and Broder Tuck discoveries within Licence 12/06, offshore Denmark.

Contingent gas Resources are attributable to the Alen field, in which PA has a unitised 0.285% working interest. ERCE has not determined the Contingent gas Resources for Alen; the estimates presented herein are those advised by PA.

Summary of Results

Our estimates of remaining Reserves and Contingent oil, gas, condensate and LPG Resources are summarised in Tables 2 and 3, and listed by class and fluid in more detail in Table 4 to Table 8. In these tables we list gross Reserves or Resources, and the Reserves or Resources net to PA's working interest taking due consideration, where applicable, of any volumetric extension of the field or discovery outside the licence in question. The tabulated estimate of PA's net working interest takes into account the working interest in the licence/permit/concession and the average of our estimates of PA's working interest in the field or discovery, where not unitized.

The Broder Tuck, Zarat, Elyssa, El Nisr, Yolanda, and Diega discoveries, and the Alen and Aseng fields contain non-hydrocarbon gases at varying percentages. Development of the Zarat discovery will require removal and sequestration of significant quantities of carbon dioxide, for which plans are in progress. All Contingent gas Resources quoted in this letter are gross gas, including non-hydrocarbon gases, barring those of the Alen field, which are the operator's latest estimates, following allowance for the removal of non-hydrocarbon gases, fuel and shrinkage.

Methodology

ERCE has carried out this audit using data and information made available by PA. These data comprise details of PA's licence interests, basic exploration and engineering data where available (including seismic data, well logs, core, fluid and test data) technical reports, interpreted data, production performance data and, where applicable, outline development plans.

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.

In estimating petroleum in place and recoverable, ERCE has used standard techniques of petroleum engineering and geoscience. These techniques combine geophysical and geological knowledge with detailed information concerning 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 determined the range of petroleum initially in place and recoverable.

No site visit was undertaken in the generation of this letter.

PA is currently in the process of farming-out the Zarat permit, and the production concessions therein, to EnQuest plc. ERCE presumes this transaction will be completed in the computation of net PA Reserves and Contingent Resources for the Didon field and the Didon North, Zarat, Elyssa and El Nisr discoveries.

ERCE notes that the Tunisian state oil company, ETAP, has an automatic right to participate in the Didon North, Elyssa, El Nisr and Zarat developments, for up to 55% working interest. Our estimates of

Contingent Resources, net to PA, for these assets does not account for the ETAP back-in. It should be noted that appraisal activity is planned within the Elyssa, El Nisr, Broder Tuck and Lille John discoveries that may materially affect our estimates of Contingent Resources.

Confirmations and Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, reservoir engineering and economics assessment. Except for the provision of professional services on a time-based fee basis, ERCE has no commercial arrangement with any other person or company involved in the interests which are the subject of this report. ERCE confirms that it is independent of PA, its directors, senior management and advisers.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The work has been supervised by Dr Adam Law, Geoscience Director of ERCE, a post-graduate in Geology, a Fellow of the Geological Society and a member of the Society of Petroleum Evaluation Engineers (No 726).

Yours faithfully

ERC Equipoise Limited

Adam Law
Geoscience Director

Table 2: Summary of total Remaining oil and condensate Reserves as at 30th June 2014, gross and attributable to PA

	Gross Economic Reserves 30/06/2014 (MMstb)			Net PA Economic Reserves 30/6/2014 (MMstb)		
	1P	2P	3P	1P	2P	3P
Oil and Condensate (MMstb)	103.02	130.83	152.46	4.53	6.76	8.39

Table 3 Summary of total Contingent Resources, gross and attributable to PA

	Gross Contingent Resources			Net PA Contingent Resources		
	1C	2C	3C	1C	2C	3C
Oil and Condensate (MMstb)	130.70	200.55	367.77	17.07	26.62	49.74
Produced Gas (Bscf)[1]	2,365.91	3,144.20	4,483.15	226.58	309.15	444.44
LPG (M tonnes)[2]	380.50	593.00	927.50	70.13	110.10	173.93

[1] Gas before deduction of inerts, shrinkage and fuel, where appropriate

[2] Based upon assumed LPG yields for proposed onshore plant upgrade

Table 4: Remaining Oil and Condensate reserves by field, as at 30th June 2014, gross and attributable to PA

Field	Gross Oil Economic Reserves 30/06/2014 (MMstb)			PA Working Interest (%)	Net PA Oil Economic Reserves 30/06/2014 (MMstb)		
	1P	2P	3P		1P	2P	3P
Aseng [1]	51.11	77.67	98.68	5.70%	2.91	4.43	5.62
Alen [2]	49.40	49.40	49.40	0.285%	0.14	0.14	0.14
Didon [3]	0.93	1.44	1.52	30.00%	0.28	0.43	0.46
DST	1.57	2.31	2.85	70%-95%	1.19	1.76	2.17
TOTAL	**103.02**	**130.83**	**152.46**		**4.53**	**6.76**	**8.39**

[1] Aseng Reserves are Oil+Condensate . Entitlement reserves Net PA are 2.16 MMstb, 3.09 MMstb, 3.87 MMstb (1P,2P,3P)

[2] Alen Reserves are Condensate and the Gross Reserves are full field. ERCE has not audited the Reserves of the Alen field. Entitlement reserves Net PA are 0.1 MMstb, 0.1 MMstb, 0.1 MMstb (1P,2P,3P)

[3] Assuming ratification of EnQuest farm-in, with PA's resulting interest 30%

Table 5: Contingent oil Resources by discovery, gross and attributable to PA

Discovery	Gross Contingent Oil Resources (MMstb)			PA Working Interest (%)	Net PA Contingent Oil Resources (MMstb)		
	1C	2C	3C		1C	2C	3C
Aseng	15.30	15.30	17.70	5.70%	0.87	0.87	1.01
Diega[1]	32.00	60.00	113.00	4.28%	1.25	2.51	5.13
Zarat[2,3,4]	21.95	36.06	83.18	15.00%	3.29	5.41	12.48
Didon[2]	2.60	3.90	5.85	30.00%	0.78	1.17	1.76
Didon North[2,4]	1.20	2.60	5.90	30.00%	0.36	0.78	1.77
Elyssa[2,4]	0.50	1.00	2.10	30.00%	0.15	0.30	0.63
DST	0.83	1.24	1.73	70%-95%	0.58	0.87	1.21
Lille John	13.60	24.50	44.30	24.00%	3.26	5.88	10.63
TOTAL	**87.98**	**144.60**	**273.76**		**10.55**	**17.79**	**34.61**

[1] ERCE estimates 4.28% working interest is based on 75% of Diega lying in Block I of which PA owns 5.7%.
In the 1C and 3C cases respectively, 68% and 80% are assumed, based on estimates of the % of the oil leg that extends onto Block I in each case

[2] Assuming ratification of EnQuest farm-in, with PA's resulting interest 30%.

[3] Net PA interest calculated using 50:50 cost split agreed between Zarat permit and Joint oil block, and ratification of EnQuest farm-in. Discovery is not unitized

[4] No provision for ETAP back-in, which can be up to 55%

Table 6: Contingent condensate Resources by discovery, gross and attributable to PA

Discovery	Gross Contingent Condensate Resources (MMbbl)			PA Working Interest (%)	Net PA Contingent Condensate Resources (MMbbl)		
	1C	2C	3C		1C	2C	3C
Diega[1]	6.93	7.95	8.96	4.28%	0.29	0.34	0.38
Zarat[2,3]	28.17	36.65	67.83	15.00%	4.22	5.50	10.17
Elyssa[2]	2.92	4.65	7.52	30.00%	0.88	1.40	2.26
El Nisr[2,4]	1.10	1.60	2.30	23.40%	0.26	0.37	0.54
Broder Tuck	3.60	5.10	7.40	24.00%	0.86	1.22	1.78
TOTAL	**42.72**	**55.95**	**94.01**		**6.51**	**8.83**	**15.12**

[1] ERCE estimates 4.28% working interest is based on 75% of Diega lying in Block I of which PA owns 5.7%.

[2] Assuming ratification of EnQuest farm-in, with PA's resulting interest 30%. No provision for ETAP back-in, which can be up to 55%

[3] Net PA interest calculated using 50:50 cost split agreed between Zarat permit and Joint oil block, and ratification of EnQuest farm-in. Discovery is not unitized
Includes condensate from onshore plant

[4] Approximately 78% of the El Nisr discovery lies in the Zarat permit.
Net PA Resources computed using this split, multiplied by PA WI of 30% post EnQuest farm-in

Table 7: Contingent gas Resources, by discovery, gross and attributable to PA

Discovery	Gross Contingent Gas Resources (Bscf)			PA Working Interest (%)	Net PA Contingent Gas Resources (Bscf)		
	1C	2C	3C		1C	2C	3C
Aseng	526.71	615.49	881.82	5.70%	30.02	35.08	50.26
Diega[1]	84.87	121.00	184.86	4.28%	3.57	5.11	7.83
Yolanda[2]	291.00	473.00	770.00	5.70%	16.59	26.96	43.89
Alen[3]	537.00	705.00	964.00	0.285%	1.53	2.01	2.75
Zarat[4,5]	638.06	792.80	1,008.41	15.00%	95.71	118.92	151.26
Elyssa[4,6]	169.00	274.00	450.00	30.00%	50.70	82.20	135.00
El Nisr[4,7]	26.50	38.20	55.10	23.40%	6.20	8.94	12.89
Broder Tuck	88.06	116.21	153.66	24.00%	21.13	27.89	36.88
Lille John	4.70	8.50	15.30	24.00%	1.13	2.04	3.67
TOTAL	**2,365.91**	**3,144.20**	**4,483.15**		**226.58**	**309.15**	**444.44**

[1] ERCE estimates 4.28% working interest is based on 75% of Diega lying in Block I of which PA owns 5.7%.
Resources are gross gas, including non-hydrocarbon gases. 2C conversion factor to sales gas 0.72

[2] Block I volumes only, gross and net

[3] ERCE has not audited the Contingent Resources of the Alen field. Operator's resources, corrected for non-hydrocarbon gases, fuel and shrinkage, are presented here

[4] Assuming ratification of EnQuest farm-in, with PA's resulting interest 30%. No provision for ETAP back-in, which can be up to 55%

[5] Net PA interest calculated using 50:50 cost split agreed between Zarat permit and Joint oil block, and ratification of EnQuest farm-in. Discovery is not unitized
Resources are gross gas, including non-hydrocarbon gases. 2C conversion factor to sales gas is 0.35

[6] Resources are gross gas, including non-hydrocarbon gases. 2C conversion factor to sales gas is 0.78

[7] ERCE estimates approximately 78% of the El Nisr discovery lies in the Zarat permit.
Net PA Resources computed using this split, multiplied by PA WI of 30% post EnQuest farm-in
Resources are gross gas, including non-hydrocarbon gases. 2C conversion factor to sales gas is 0.85

Table 8: Contingent LPG Resources, by discovery, gross and attributable to PA

Discovery	Gross Contingent LPG Resources (M tonnes)			Net PA Contingent LPG Resources (M tonnes)		
	1C	2C	3C	1C	2C	3C
Zarat[1,2]	293.50	452.00	695.50	44.03	67.80	104.33
Elyssa[1]	87.00	141.00	232.00	26.10	42.30	69.60
TOTAL	**380.50**	**593.00**	**927.50**	**70.13**	**110.10**	**173.93**

[1] Assuming ratification of EnQuest farm-in, with PA's resulting interest 30%, and PA's current development plan. No provision for ETAP back-in, which can be up to 55%

[2] Net PA interest calculated using 50:50 cost split agreed between Zarat permit and Joint Oil block, assuming ratification of EnQuest farm-in. Discovery is not unitized

Contingent LPG Resources for other PA properties have not been assessed, as ERCE estimates these volumes are not material to PA,
or a development case for LPG has not been presented

Appendix 1: SPE PRMS Guidelines

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.

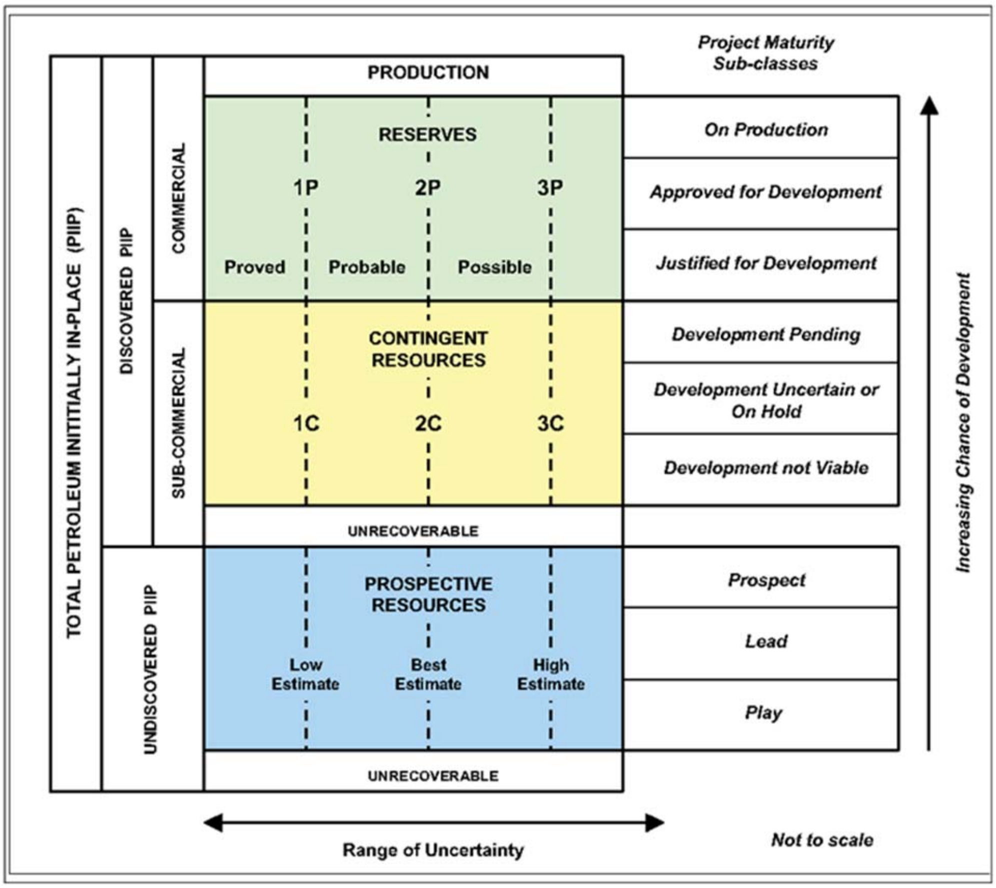

Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

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:

the area delineated by drilling and defined by fluid contacts, if any, and

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 the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and 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

"1C"	means low estimate of Contingent Resources, as defined in Appendix 1
"2C"	means best estimate of Contingent Resources, as defined in Appendix 1
"3C"	means high estimate of Contingent Resources, as defined in Appendix 1
"bbl"	means barrels
"Bscf"	means thousands of millions of standard cubic feet
"LPG"	means liquefied petroleum gas
"M" "MM"	means thousands and millions respectively
"NPV"	means net present value
"NPV10"	means net present value with a discount factor of 10%
"P" or "1P"	means Proved, as defined in Appendix 1
"P+P" or "2P"	means Proved+Probable, as defined in Appendix 1
"P+P+P" or "3P"	means Proved+Probable+Possible, as defined in Appendix 1
"remaining"	means, when stating reserves of petroleum, the total amount of petroleum which is expected to be produced from the reference date to the end of production
"scf"	means standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"stb"	means a standard barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit

30 September 2014

The Directors
PA Resources AB
Kungsgatan 44, 3rd Floor
SE-111 35 Stockholm
Sweden

Dear Sirs

Re: Valuation of Reserves and Certain Contingent Resources, PA Resources AB

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has reviewed the Reserves and certain Contingent Resources held by PA Resources AB and its subsidiaries ("PA") within its Equatorial Guinean, Tunisian and Danish properties. We have used information and data available and reasonable forward-looking expectations made up to or before 30 June 2014. Our estimates of Reserves and Contingent Resources are summarised in our letter to you, dated 26 September 2014, entitled "Audit of Reserves and Certain Contingent Resources, PA Resources AB".

At PA's request, we have performed an economic valuation of our estimates of Reserves and Contingent Resources as disclosed in the above letter. As per PA's request, the effective date for this valuation is 1 January 2015. Nomenclature used in this letter is summarised in Appendix 2.

In the estimation of future cash flows, ERCE has estimated commodity prices, based on recent and current market trends. Gas prices in Equatorial Guinea and Tunisia are as advised by PA. These are uncertain, and there is no guarantee that actual economic parameters will match the assumed values. The Net Present Values (NPVs) presented in this letter simply represent discounted future cash flow values. Although NPVs form an integral part of fair market value estimations, without consideration for other economic and commercial criteria they cannot to be construed as being ERCE's opinion of fair market value.

Development planning for the assessed Contingent Resources is at variable levels of maturity. The NPVs presented in this letter may therefore be subject to significant change as development planning and asset appraisal continues. Contingent Resources can be classified as such for reasons other than economics, such as third party, regulatory and/or contract approvals. In the valuation work, ERCE has not applied any risking factors for these types of consideration.

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Tel: +44 (0)20 8256 1150

This letter is for the sole use of PA and its 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 ERCE. ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees. In the case that material is delivered in digital format, ERCE does not accept any responsibility for edits carried out after the product has left the Company's premises.

This letter has been issued in advance of our final report to PA.

Introduction

PA holds varying equity interests in exploration licences and permits and production concessions offshore Denmark, offshore Equatorial Guinea and onshore and offshore Tunisia. A summary of the properties reviewed is presented in Table 1.

Table 1: Properties reviewed

Country	Licence/Permit/Concession	PA Interest (%)	Field or Discovery	Expiry of Current Phase	Remaining Work Commitments in this Phase	Notes
Equatorial Guinea	Block I	0.285%	Alen	Jan. 2036	None	Unitized interest.
	Block I	5.70%	Aseng	Jun. 2034	None	
	Block I	4.28%	Diega	Jun. 2034	None	Not yet unitized. PA interest is estimated.
	Block I	5.70%	Yolanda	Jun. 2034	None	
Tunisia	Didon concession	30.00%	Didon	Dec. 2027	None	After completion of EnQuest farm-in.
	Zarat: concession pending	15.00%	Zarat	N/A	N/A	Not yet unitized. PA interest estimated using current agreed cost split.After completion of EnQuest farm-in.
	Zarat permit	30.00%	Elyssa	Jul. 2015	2 wells	After completion of EnQuest farm-in.
	Zarat permit	30.00%	Didon North	Jul. 2015		After completion of EnQuest farm-in.
	Zarat permit	23.40%	El Nisr	Jul. 2015		Not yet unitized. PA interest estimated. After completion of EnQuest Farm-in.
	Douleb concession	70.00%	Douleb	Dec. 2035	1 well	
	Semmama concession	70.00%	Semmama	Dec. 2025	None	
	Tamesmida concession	95.00%	Tamesmida	Dec. 2035	None	
Denmark	Licence 12/06	24.00%	Broder Tuck	May 2016	None	After Dana Farm-in.
	Licence 12/06	24.00%	Lille John	May 2016	1 well	After Dana Farm-in.

Our estimates of Reserves and Contingent Resources for the above fields and discoveries are presented in our letter "Audit of Reserves and Certain Contingent Resources, PA Resources AB", dated 16 September 2014.

Summary of Results

Our estimates of NPV10 net to PA, with a valuation date of 1/1/2015, are summarised in Tables 2 and 3 of this letter.

The Broder Tuck, Zarat, Elyssa, El Nisr, Yolanda and Diega discoveries and the Alen and Aseng fields contain non-hydrocarbon gases at varying percentages. Development of the Zarat discovery will require removal and sequestration of significant quantities of carbon dioxide, for which plans are in progress. Our valuations include reduction factors applied to the gross gas produced in order to compute sales gas. These reduction factors at the 2C level of confidence are 0.35 for Zarat, 0.78 for Elyssa, 0.85 for El Nisr, and 0.72 for the Diega discovery. The volumes of sales gas that result from our evaluation of these properties, subject to economic cut-off, are summarised in Table 4. Our valuations take due account of the removal of non-hydrocarbon gases, where appropriate.

Methodology

ERCE has carried out this audit using data and information made available by PA. These data comprise details of PA's licence interests, basic exploration and engineering data where available (including seismic data, well logs, core, fluid and test data) technical reports, interpreted data, production performance data and, where applicable, outline development plans.

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.

In estimating petroleum in place and recoverable, ERCE has used standard techniques of petroleum engineering and geoscience. These techniques combine geophysical and geological knowledge with detailed information concerning 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 determined the range of petroleum initially in place and recoverable.

In our valuation, ERCE has evaluated the development schemes presented by PA and conducted an audit of the capital and operating costs. Production profiles have been generated consistent with the estimates of Reserves and Contingent Resources, which have then been used in an economic model provided by PA Resources, suitably audited, based upon the current fiscal terms associated with the licences. At PA's request, the effective date of our valuation is 1 January 2015.

No site visit was undertaken in the generation of this letter.

PA is currently in the process of farming-out the Zarat permit, and the production concessions therein, to EnQuest plc. This involves a series of cash payments and staged carries based on various development and volume metrics. ERCE presumes this transaction will be completed, and has taken due account of these arrangements in our valuation of the Contingent Resources associated with Zarat and Elyssa. We have not taken into account any cash payments made to PA as part of the EnQuest farm-in.

PA has recently farmed-out a proportion of its interest in Licence 12/06, which contains the Lille John and Broder tuck discoveries, to Dana Petroleum, resulting in certain carries during the appraisal phase of these two discoveries. We have taken due account of this arrangement when estimating net PA Contingent Resources and NPV. In estimating NPV for the Diega discovery, we have assumed that, on average, 75% of the discovery lies on Block I.

ERCE notes that the Tunisian state oil company, ETAP, has an automatic right to participate in the Didon North, Elyssa, El Nisr and Zarat developments, for up to 55% working interest. In the valuation presented here, ERCE has modelled this participation right as being taken up at a 50% working interest to be consistent with PA's internal valuation. For Zarat, our valuation of the 2C estimate of Contingent Resources is $310.1MM with no ETAP back-in, and $142.9MM with a 55% ETAP back-in. For Elyssa, our valuation of the 2C estimate of Contingent Resources is $97.5MM with no ETAP back-in, and $49.7MM with a 55% ETAP back-in.

Confirmations and Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, reservoir engineering and economics assessment. Except for the provision of professional services on a time-based fee basis, ERCE has no commercial arrangement with any other person or company involved in the interests which are the subject of this report. ERCE confirms that it is independent of PA, its directors, senior management and advisers.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The work has been supervised by Dr Adam Law, Geoscience Director of ERCE, a post-graduate in Geology, a Fellow of the Geological Society and a member of the Society of Petroleum Evaluation Engineers (No 726).

Yours faithfully

ERC Equipoise Limited

Adam Law
Geoscience Director

Table 2: Net Present Value (NPV10) attributable to PA of remaining Reserves by field, and aggregated, as at 1 January 2015

Field	NPV10 Net PA ($MM) Effective 01/01/2015		
	1P	2P	3P
Aseng + Alen (Block I)	82.7	108.3	128.0
Didon	-15.6	-9.8	-7.8
DST	8.9	14.0	18.7
TOTAL	**76.0**	**112.5**	**138.9**

Table 3: Net Present Value (NPV10) attributable to PA of Contingent Resources by discovery, and aggregated, as at 1 January 2015

Discovery	NPV10 Net PA ($MM) Effective 01/01/2015		
	1C	2C	3C
Aseng + Alen + Diega (Block I Incremental Liquids)	23.8	48.4	65.2
Aseng + Alen + Diega + Yolanda (Block I Incremental Gas)	20.9	30.4	39.0
Zarat	90.8	158.1	211.1
Elyssa	24.1	54.1	93.9
El Nisr	-0.1	3.2	7.5
Didon	10.5	25.0	48.1
Didon North	0.0	14.8	47.8
DST	3.5	7.3	10.8
Broder Tuck	41.2	52.5	81.1
Lille John	58.7	94.9	181.7
TOTAL	**273.4**	**488.6**	**786.0**

Table 4: Sales gas from Contingent gas Resources, post valuation, gross and attributable to PA

Discovery	Gross Economic Sales Gas Resources (Bscf) Effective 01/01/2015			PA Working Interest (%)	Net PA Economic Sales Gas Resources (Bscf) Effective 01/01/2015 (No ETAP Back In)			Net PA Economic Sales Gas Resources (Bscf) Effective 01/01/2015 (50% ETAP Back-In)		
	1C	2C	3C		1C	2C	3C	1C	2C	3C
Aseng + Alen + Diega + Yolanda (Block I Incremental Gas)[1]	682.30	907.28	1398.61	5.70%	38.89	51.71	79.72	38.89	51.71	79.72
Zarat[2,3]	172.89	274.89	428.68	15.00%	25.93	41.23	64.30	12.97	20.62	32.15
Elyssa[2]	131.93	213.89	351.27	30.00%	39.58	64.17	105.38	19.79	32.08	52.69
El Nisr[3,5]	22.54	32.50	46.87	23.40%	5.28	7.60	10.97	2.64	3.80	5.48
Broder Tuck	76.15	105.01	136.07	24.00%	18.28	25.20	32.66	18.28	25.20	32.66

[1] Gas Resources Gross Block I

[3] Assuming Ratification of EnQuest farm-in, with PA's resulting interest 30%

[4] Net PA interest calculated using 50:50 cost split agreed between Zarat permit and Joint oil block, and ratification of EnQuest farm-in. Discovery is not unitized

[5] ERCE estimates approximately 78% of the El Nisr discovery lies in the Zarat permit.
Net PA Resources computed using this split, multiplied by PA WI of 30% post EnQuest farm-in

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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.

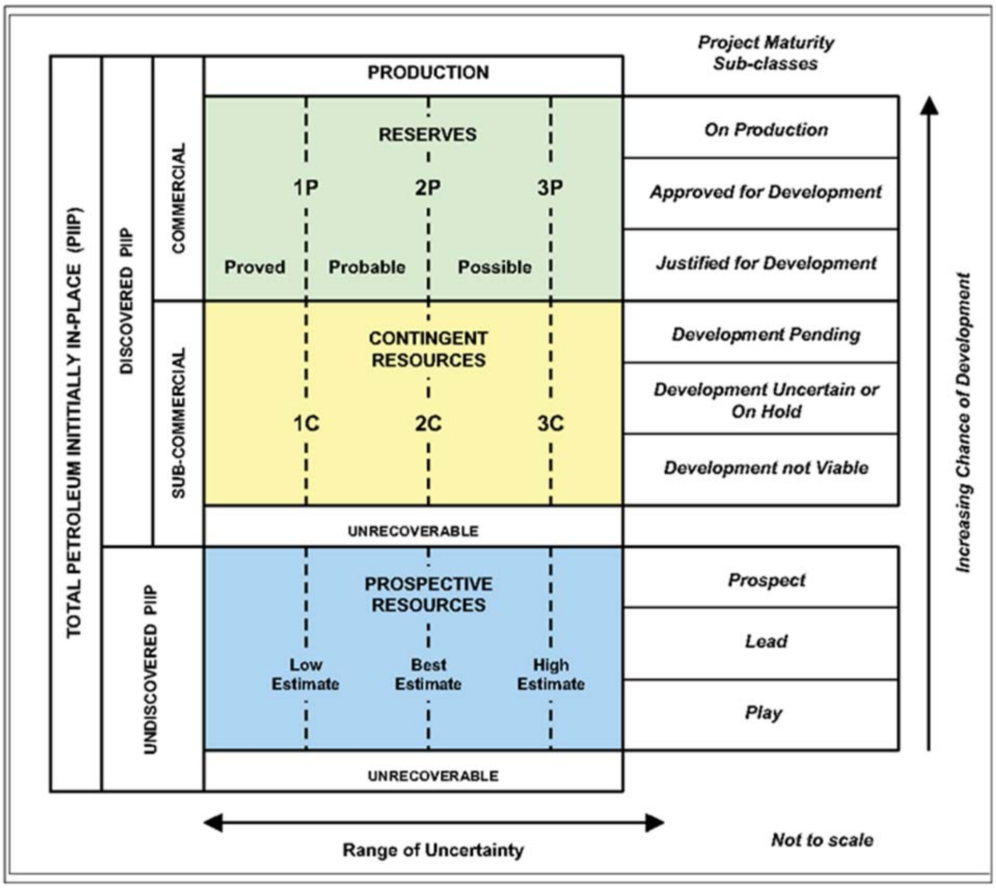

Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

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:

the area delineated by drilling and defined by fluid contacts, if any, and

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 the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and 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

"1C"	means low estimate of Contingent Resources, as defined in Appendix 1
"2C"	means best estimate of Contingent Resources, as defined in Appendix 1
"3C"	means high estimate of Contingent Resources, as defined in Appendix 1
"bbl"	means barrels
"Bscf"	means thousands of millions of standard cubic feet
"LPG"	means liquefied petroleum gas
"M" "MM"	means thousands and millions respectively
"NPV"	means net present value
"NPV10"	means net present value with a discount factor of 10%
"P" or "1P"	means Proved, as defined in Appendix 1
"P+P" or "2P"	means Proved+Probable, as defined in Appendix 1
"P+P+P" or "3P"	means Proved+Probable+Possible, as defined in Appendix 1
"remaining"	means, when stating reserves of petroleum, the total amount of petroleum which is expected to be produced from the reference date to the end of production
"scf"	means standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"stb"	means a standard barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit