20 February 2013

The Board of Directors
Atlantic Petroleum
Yviri við Strond 4
FO-110 Tórshavn
Faroe Islands

Dear Sirs

Evaluation of the Petroleum Assets of Atlantic Petroleum & its Subsidiary Companies

In response to your request, Fugro Robertson Limited (Robertson) have reviewed and valued the petroleum interests of Atlantic Petroleum P/F (AP) and its subsidiary companies offshore the United Kingdom Continental Shelf (UKCS), offshore Ireland, offshore Netherlands, offshore Norway and The Faroe Islands Offshore Area. The evaluation is at 1 January 2013 and is based on technical data and information available and provided by AP up to 12 January 2013. This report documents the review and valuation of AP and comprises a Competent Persons Report (CPR) for Danish and Icelandic stock market purposes.

1. PROFESSIONAL QUALIFICATIONS

Robertson, a CGG company, is a geological and petroleum reservoir consultancy that provides a specialist service in the assessment and valuation of upstream petroleum assets. In preparing this report Robertson have also used the services of a number of independent petroleum consultants. In line with Chapter 19 Section 12 (b) of the Listing Rules of the London Stock Exchange, the key personnel in each technical and commercial discipline who have supervised the evaluation and writing of this report each have in excess of five years professional experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Robertson have reviewed and valued the assets of AP on a number of occasions. The last valuation was dated January 2012 and also took the form of a CPR.

Except for the provision of professional services on a fee basis, Robertson have no commercial arrangement or interest with the company or the assets that are the subject of this report or any other person or company involved in the interests.

2. INTRODUCTION AND LICENCE DESCRIPTIONS

2.1 History

AP was formed in February 1998 as an independent Faroese upstream oil and gas company. Since that time it has been awarded exploration licences in the Faroe Islands, the Netherlands and the UK. Additionally the company has completed several UK asset acquisitions and farmed into UK and Eire exploration and appraisal acreage. AP acquired a Norwegian company, Emergy Exploration AS in December 2012. AP is listed on the Nasdaq OMX on Iceland and in Copenhagen.

The Chestnut field came on stream on 20 September 2008. The Ettrick field came on stream on 15 August 2009. The nearby 20/2a-8 Blackbird prospect was drilled and declared an oil discovery in mid August 2008. The Blackbird discovery was successfully tied back to the Ettrick production facilities and came on stream 13 November 2011.

2.2 AP Activity in 2012

On AP's producing fields, a second water injector well was drilled on the Ettrick field and brought online in June; a water injector well was drilled on the Blackbird field in late 2012 and is expected to be online in January 2013; the sidetracked water injector well on the Chestnut field that was brought online at the end of 2011 provided effective support to the reservoir through 2012. The Chestnut field produced at an average rate of 5,892 BOPD in 2012. The Ettrick field produced at an average rate of 14,343 BOPD in 2012. The Blackbird field produced at an annual average rate of 3,735 BOPD in 2012.

The delayed award of UKCS 26th Round blocks in January resulted in AP gaining five licences in the Southern North Sea. Four licences have been acquired so far in the UKCS 27th Round consisting of four part blocks and seven blocks.

During 2012 a number of exploration wells were drilled. The Orchid well on P1556 was drilled in March to May and was P&A an oil discovery in the Chalk. The drilling of the Brugdan Deep exploration well was commenced in June offshore the Faroes, but drilling activity was suspended in November due to the imminence of the inclement weather season. It is planned to re-enter the well and resume drilling in 2013. AP farmed into the P1100 Polecat licence and drilled a well in October to November. The Spaniards well on P218, the costs of which were carried for AP, was drilled in October to November.

The acquisition of Emergy Exploration AS was announced and completed in November. This augments considerably the positioning of AP with entry to Norway and includes a gas discovery, Agat.

A 25% working interest in two UK discoveries, Orlando and Kells, was acquired in December. It is expected that these will be developed and on production within two to three years as satellites to the Ninian field in the Northern sector of the UKCS.

Entry to the Netherlands was secured with the planned transfer of equity from Centrica of four blocks in November.

2.3 AP Current Licence Interests

The current licence interests held by AP in the UK are summarised below.

Licence	Blocks	AP Interest (%)
P354	22/2a	15%
P273/ P317/ P1580	20/2a, 20/3a /20/3f	8.27%/9.4% (Note 1)
P218 & P588	15/21a, b, c & f	13.35%
P1100	20/4a & 20/9a	20%
P1556	29/1c	10%
P1606	3/3b	25%
P1607	3/8d	25%
P1610 & P1766	13/23a & 13/22d	20%
P1655	15/21g (& P218 15/21a Gamma subarea)	3.24%
P1673	44/28a	5%
P1716	49/29e, 49/30b	35%
P1724	43/13b	10%
P1727	43/17b, 43/18b	10%
P1734	48/8c	10%
P1747	49/2c	10%
P1748	49/4d & 49/9d	10%
P1767	14/9, 14/14a, 14/15	30%
P1791	21/30e	20%
P1828	36/23a, 36/24a, 36/27, 36/28 & 36/29	10%
P1857	49/30f	50%
P1858	42/24a & 42/25c	100%
P1860	47/9d, 47/10d	100%
P1883	37/5, 37/10a & 38/1 & 38/6a	100%
P1899	44/4a, 44/5 & 45/1	10%
P1905	44/30b	10%
P1906	47/2b, 47/3g, 47/7a & 47/8d	10%
P1924	44/17e	100%

P1927	48/13c, 48/14b, 48/18e & 48/19d	100%
P1993	205/23, 205/24, 205/25, 205/28, 205/29, 205/30	43%
P1933	15/16e	33%
P2069	205/12	30%
P2082	30/12c, 30/13c, 30/18c	30.5%

1. AP has a 8.27% interest in the Ettrick field and in the licences, but a 9.39773% interest in the Blackbird field.

The current licence interests held by AP in Faroe Islands, Ireland, Netherland and Norway are summarised below.

Country	Licence	Blocks	AP Interest (%)
Faroe Islands	FL006	6104/16a, 6104/21, 6105/25	1%
Faroe Islands	FL014	6104/14	40%
Faroe Islands	FL016	6202/6a, 7, 8, 9, 10a, 11, 12, 13, 14, 15, 16, 17, 18, 21a, 22a, 6203/14a, 15a, 16, 17, 18, 19, 20, 21, 22, 23, 24a, 25a	10%
Ireland	SEL 2/07	49/9, 13, 14, 18, 19, & 50/6, 7, 11	18.333% / 13.75%
Netherlands	NL	E1, E2, E4 & E5	6%
Norway	PL270	35/3	15%
Norway	PL559	6608/10, 11	10%

3. DATA AND EVALUATION BASIS

3.1 History

Robertson have evaluated the assets of AP on a number of occasions from 2003 onwards. These evaluations have been used for stock rights issues and flotations on the Icelandic and Danish stock exchanges. The last evaluation was effective at 1 January 2012 and was presented as a CPR and also a Reserves Report within the AP Annual Report and Accounts.

3.2 Data

In undertaking this evaluation Robertson have relied solely upon data supplied by AP. In particular Robertson have relied upon AP for the accuracy and completeness of the data set provided. This data included recent partner meeting presentations, meeting minutes, related notes and commercial documentation, budgets and field development plans. In some instances the data also comprised raw or interpreted geological and engineering data.

In estimating petroleum in place and recoverable, Robertson have used the standard techniques of petroleum engineering. There is uncertainty inherent in both the measurement and interpretation of basic geological and petroleum data. Robertson have estimated the degree of this uncertainty to calculate the potential range of petroleum initially in place and recoverable. There is no guarantee that the ultimate volumes of petroleum recovered from the respective fields and prospects will fall within the ranges quoted in this report. Robertson have used the guidelines of Chapter 19 of the Listing Rules of the London Stock Exchange as a guide for the reporting standard but has also included the estimated value of exploration prospects.

Robertson have independently assessed the proposed development schemes and validated estimates of capital, operating and decommissioning costs, modifying these where it is judged appropriate. For discoveries and prospects where possible development schemes have not been presented Robertson have assessed the location and field characteristics in order to define potential production methods based upon conventional technology.

Robertson have carried out economic modelling of all of the assets where sufficient data exists, based on our forecasts of costs and production. The capital and operating costs have been combined with production forecasts based on the resources or reserves and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. Our valuations do not take into account any outstanding debt, nor future indirect corporate costs such as general and administrative costs.

Robertson have valued the petroleum assets using the industry standard discounted cash flow technique. In estimating the future cash flows of the assets Robertson have used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

When evaluating the prospective and contingent resources comprising the exploration and appraisal prospects, Robertson have estimated the geological and development chance of success and the expected monetary value outcome of each prospect. Those with a positive outcome are deemed to be viable to drill and their estimated risked reserve and values have been included in the valuation. There is no guarantee that any of the exploration prospects will contain hydrocarbons. There is also no guarantee that if the exploration prospects do hold hydrocarbons that they will be commercially viable or will have any value.

The resource and reserve definitions and nomenclature used in this evaluation and report are detailed in Appendices A and B respectively.

4. SUMMARY OF RESOURCES AND RESERVES

The UKCS Chestnut field came on production in September 2008 and the Chestnut South appraisal was tied back to the Chestnut field in early 2009. The Ettrick development came on production in August 2009. The Blackbird field has been on production since November 2011. The Orlando development is progressing towards final FDP approvals with first oil planned for the second half of 2014.

Robertson consider these assets to contain petroleum reserves and estimate the remaining economically recoverable volumes attributable to AP by asset and in aggregate to be as follows:

Petroleum Reserves Remaining at 1 January 2013 (MMBOE)			
Field	**P90**	**P50**	**P10**
Chestnut	0.5	0.7	0.9
Ettrick	0.5	0.9	1.5
Blackbird	0.2	0.5	1.5
Orlando	1.9	3.0	4.6
Aggregated Total	**3.2**	**5.1**	**8.3**

Note: In all tables the numbers have been rounded

A number of discoveries on the UKCS, in the Irish Celtic Sea and Norway have established the existence of petroleum. However, commerciality of the assets may not have been established, development plans have not been sanctioned, and consequently Robertson consider these assets to contain contingent resources.

Robertson estimate the volumes attributable to AP by asset and in aggregate to be as presented in the following table. Where a figure is not stated this is generally due to insufficient data to fully evaluate the asset.

Contingent Resources at 1 January 2013 (MMBOE)			
Discovery	**P90**	**P50**	**P10**
Bright	0.2	0.5	1.7
Dolphin	---	1.1	---
Gamma Central	---	0.3	---
North East Perth Terrace	---	0.4	---
Perth	2.0	2.9	4.6
Fulham & Arrol	---	0.8	---
Pegasus North	---	0.3	---
Polecat	2.0	4.2	7.2
Orchid	---	---	---
Kells	2.1	3.7	5.1
Helvick	---	0.3	---

Hook Head	---	---	---
Agat	---	8.6	---
Aggregated Total	**---**	**23.1**	**---**

Of the exploration and appraisal prospects that Robertson have evaluated, fifteen are deemed to be economically viable to drill. Robertson estimate the prospective resources of the exploration and appraisal prospects attributable to AP by asset and in aggregate to be as presented in the following table.

Prospective Resources at 1 January 2013 (MMBOE)			
Prospect	**P50 Un-Risked**	**P50 Risked**	**Economically Viable to Drill?**
East Perth (UKCS 15/21a)	0.7	0.4	Yes
North West Perth Terrace (UKCS 15/21a)	1.5	0.7	Yes
Anglesey (UKCS 14/9 & 14/14a)	5.7	1.1	Yes
Magnolia (UKCS 13/23a & 13/22d)	4.0	0.8	Yes
Birnam (UKCS15/16e)	9.9	2.2	Yes
Skerryvore (UKCS 30/12c &30/18c)	6.1	1.2	Yes
Davaar (UKCS 205/12)	55.8	5.3	Yes
Pegasus West (UKCS 43/13b)	1.6	0.3	Yes
Pegasus Flanks (UKCS 43/13b)	1.7	0.3	Yes
Selene (UKCS 48/8c)	1.6	0.3	Yes
Greater York area (UKCS P1906): Prospect B	0.8	0.4	Yes
Brugdan Deep (Faroes Licence L006)	9.2	1.2	Yes
Kúlubøkan (Faroes Licence L016)	160.0	11.5	Yes
Agat Turitella (Norway Licence PL270)	7.0	4.6	Yes
Hendricks (Norway Licence PL559)	9.9	1.9	Yes
Aggregated Total of Viable Prospects	275.5	32.2	

Yours faithfully
For and on behalf of Fugro Robertson Limited

Turlough Cooling
Director
Petroleum Reservoir and Economics Group

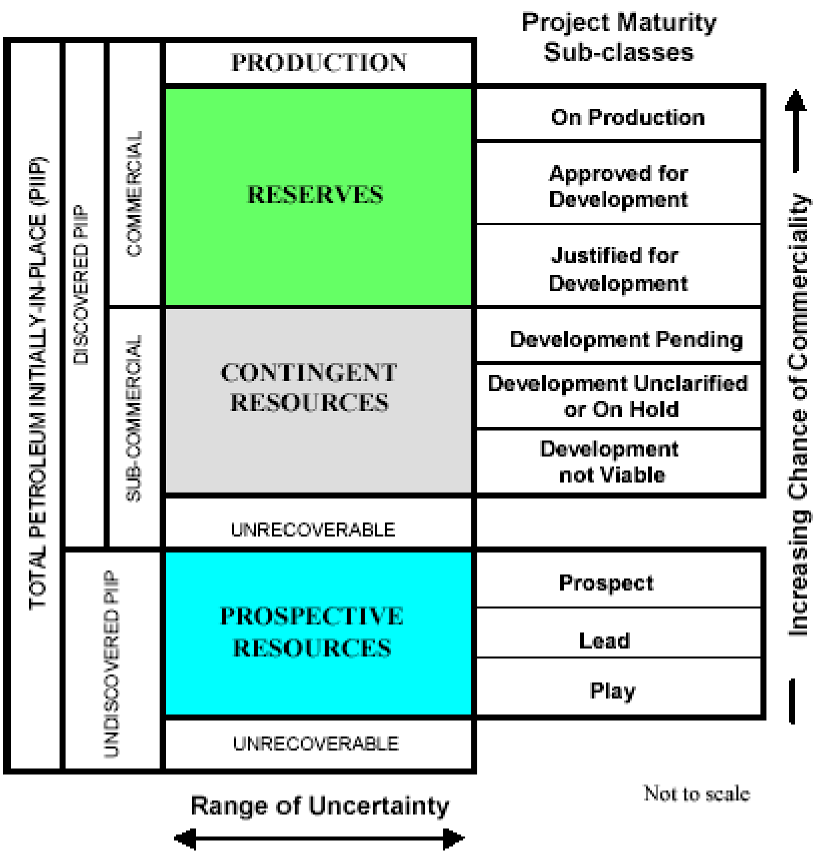
5. APPENDIX A: DEFINITIONS

5.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in 1998, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (2007) are presented below.

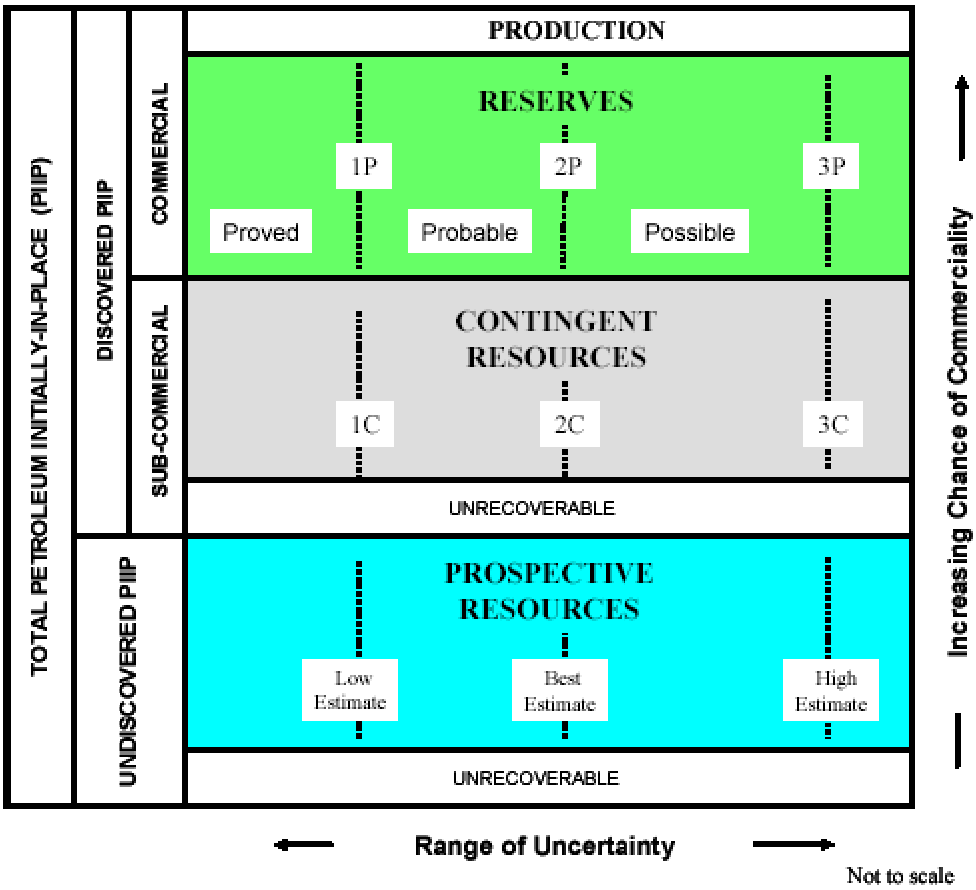
Figure 5.1: Resources Classification Framework

Source: SPE Petroleum Resources Management System 2007



Source: SPE Petroleum Resources Management System 2007

Figure 5.2: Resources Classification Framework: Sub-classes based on Project Maturity



5.1.1 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”).

5.1.2 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.

5.1.3 Undiscovered Petroleum Initially-In-Place

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

5.2 Production

Production is the cumulative quantity of petroleum that has been recovered at a given date. Production is measured in terms of the sales product specifications and raw production (sales plus non-sales) quantities required to support engineering analyses based on reservoir voidage.

5.3 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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.

The following outlines what is necessary for the definition of Reserve to be applied.

- 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
- There is evidence of firm intention to proceed with development within a reasonable time frame
- A reasonable timetable for development must be in evidence
- There should be a development plan in sufficient detail to support the assessment of commerciality
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria must have been undertaken
- There must be a reasonable expectation that there will be a market for all, or at least the expected sales quantities, of production required to justify development
- Evidence that the necessary production and transportation facilities are available or can be made available
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated

The “decision gate” whereby a Contingent Resource moves to the Reserves class is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

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.

5.3.1 Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

5.3.2 Developed Non-Producing Reserves

Developed Non-producing Reserves include shut-in and behind-pipe reserves.

Shut-in reserves are expected to be recovered from:

- Completion intervals that are open at the time of the estimate but that have not yet started producing
- Wells that were shut-in for market conditions or pipeline connections, or
- Wells not capable of production for mechanical reasons.

Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

5.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

- From new wells on undrilled acreage in known accumulations
- From deepening existing wells to a different (but known) reservoir
- From infill wells that will increase recovery, or
- Where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to:
    - Recomplete an existing well or
    - Install production or transportation facilities for primary or improved recovery projects

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Where reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years.

5.3.4 Proved Reserves

Proved Reserves are those quantities of petroleum that, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current 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.

5.3.5 Probable Reserves

Probable Reserves are those additional reserves that 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 + Probable Reserves (2P).

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.

5.3.6 Possible Reserves

Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest 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 + Probable + 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.

5.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development 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.

The term accumulation is used to identify an individual body of moveable petroleum. The key requirement in determining whether an accumulation is known (and hence contains Reserves or Contingent Resources) is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface, or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice provided there is a good analogy to a nearby, geologically comparable, known accumulation.

Estimated recoverable quantities within such discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

5.4.1 1C Contingent Resources: Development Pending

1C Contingent Resources are a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are expected to be resolved within a reasonable time frame.

5.4.2 2C Contingent Resources: Development Un-Clarified/On Hold

2C Contingent Resources are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development.

5.4.3 3C Contingent Resources: Development Not Viable

3C Contingent Resources are a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognised in the event of a major change in technology or commercial conditions.

5.5 Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective

Resources have both an associated chance of discovery and a chance of development. They are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

5.5.1 Prospect

A Prospect is classified as a potential accumulation that is sufficiently well defined to represent a viable drilling target.

5.5.2 Lead

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

5.5.3 Play

A Play is classified as a prospective trend of potential prospects that requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

5.6 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

6. APPENDIX B: NOMENCLATURE

acre	43,560 square feet
API	American Petroleum Institute (ºAPI for oil gravity, API units for gamma ray measurement)
av.	Average
AVO	Amplitude vs. Off-Set
BBO	billion (10^9) barrels of oil
bbl, bbls	barrel, barrels
BCF	billion cubic feet
bcm	billion cubic metres
BCPD	barrels of condensate per day
BHT	bottom hole temperature
BHP	bottom hole pressure
BOE	barrel of oil equivalent, with gas converted at 1 BOE = 6,000 SCF
BOPD	barrels of oil per day
BPD	barrels per day
Btu	British thermal units
BV	bulk volume
c.	circa
CCA	conventional core analysis
CD-ROM	compact disc with read only memory
cgm	computer graphics meta file
CNG	compressed natural gas
CO_2	carbon dioxide
COE	crude oil equivalent
CoS	chance of success
1-D, 2-D, 3-D	1-, 2-, 3-dimensions
DECC	Department of Energy and Climate Change
DHI	direct hydrocarbon indicators
DHC	dry hole cost
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E	East
E & P	exploration & production
EAEG	European Association of Exploration Geophysicists
e.g.	for example
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable (reserves)
FPSO	Floating production storage unit
ft/s	feet per second
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
Ga	billion (10^9) years
GIIP	gas initially in place
GIS	Geographical Information Systems
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
H_2S	hydrogen sulphide
ha	hectare(s)
HI	hydrogen index
HP	high pressure
Hz	hertz
IDC	intangible drilling costs
IRR	internal rate of return
km	kilometres (1,000 metres)
km^2	square kilometres
kWh	kilowatt-hours
LoF	life of field
LP	low pressure
LVL	low-velocity layer
M & A	mergers & acquisitions
m	metres
M	thousands
MM	million
m^3/day	cubic metres per day
Ma	million years (before present)
mbdf	metres below derrick floor
mbsl	metres below sea level
MBOPD	thousand bbls of oil per day

MCFD	thousand cubic feet per day
MCFGD	thousand cubic feet of gas per day
mD	millidarcies
MD	measured depth
mdst.	mudstone
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz
million m^3	million cubic metres
ml	millilitres
mls	miles
MMBO	million bbls of oil
MMBOE	million bbls of oil equivalent
MMBOPD	million bbls of oil per day
MMCFGD	million cubic feet of gas per day
MMTOE	million tons of oil equivalent
mmsl	metres below mean sea level
mN/m	interfacial tension measured unit
MPa	megapascals
mSS	metres subsea
m/s	metres per second
msec	millisecond(s)
MSL	mean sea level
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
NPV	net present value
no.	number (not #)
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P90	proved
P50	proved + probable
P10	proved + probable + possible
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability
PESGB	Petroleum Exploration Society of Great Britain
pH	-log H ion concentration
phi	unit grain size measurement
Ø	porosity
plc	public limited company
por.	porosity
poroperm	porosity-permeability
ppm	parts per million
psi	pounds per square inch
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
SCF	standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
SCF/STB	standard cubic feet per stock tank barrel
SS	sub-sea
ST	sidetrack (well)
STB	stock tank barrels
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
TCF	trillion (10^{12}) cubic feet
TD	total depth
TDC	tangible drilling costs
Therm	100,000 Btu
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar, the currency of the United States of America
UV	ultra-violet
W	West
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
XRD	X-ray diffraction (analysis