Gaffney, Cline & Associates

SUMMARY VERSION OF THE COMPETENT PERSON'S REPORT ON ATLANTIC PETROLEUM INTERESTS AS AT 31st DECEMBER, 2013

Prepared for

ATLANTIC PETROLEUM P/F

MARCH, 2014

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Page No.

Tables

Figures

Appendices

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MIH/kab/EL-13-217300/0600 **12th March, 2014**

The Directors
Atlantic Petroleum P/F,
26/28 Hammersmith Grove,
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SUMMARY VERSION OF THE COMPETENT PERSON'S REPORT ON ATLANTIC PETROLEUM INTERESTS AS AT 31ST DECEMBER, 2013

INTRODUCTION

Atlantic Petroleum P/F (AP) requested Gaffney, Cline & Associates (GCA) to provide an independent assessment of the oil and gas Reserves and Resources, and the Net Present Value (NPV) of the Reserves, in its assets in UK, Norwegian, Faroese, Irish and Dutch waters, in the form of a Competent Person's Report (CPR) with an effective date of 31st December, 2013. This report is a summary version of the CPR, requested by AP to fulfil Copenhagen Stock Exchange requirements and for use in its Annual Report.

BASIS OF OPINION

AP has made available to GCA a data-set of technical information, including geological, geophysical, and engineering data and reports, together with financial data and the fiscal and contractual terms applicable to each of the assets. GCA has also had meetings and discussions with AP technical and managerial personnel. In carrying out this review, GCA has relied on the accuracy and completeness of the information received from AP.

This document reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by AP and obtained from other sources e.g. public domain, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by or at the direction of AP and obtained from other sources e.g. public domain, and has accepted the accuracy and completeness of these data. GCA has no reason to believe that any material facts have been withheld from it, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geological, geophysical, and engineering data and reports, together with financial data and the fiscal and contractual data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights including environmental and abandonment obligations, and any necessary licenses and consents including planning permission, financial interest relationships or encumbrances thereon for any part of the appraised properties.

In carrying out this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report. In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with AP. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis carried out as part of this report.

Staff members who prepared this report are professionally-qualified with appropriate educational qualifications and levels of experience and expertise to perform the scope of work set out in the Proposal for Services.

GCA has not undertaken a site visit and inspection as it is considered unnecessary for the purposes of this CPR. As such, GCA is not in a position to comment on the operations or facilities in place, their appropriateness and condition and whether they are in compliance with the regulations pertaining to such operations. Further, GCA is not in a position to comment on any aspect of health, safety or environment of such operation.

In the preparation of this report GCA has used The Petroleum Resources Management System approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers in March, 2007 (see Appendix I).

Oil volumes appearing in this report have been quoted at stock tank conditions in millions of barrels (MMBbl). Natural gas volumes have been quoted in billions of standard cubic feet (Bscf) and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. Standard conditions are defined as 14.7 psia and 60° Fahrenheit.

A glossary of standard industry abbreviations and terms, some or all of which may be used in this report, is attached as Appendix II.

Definition of Reserves and Resources

Reserves are those quantities of petroleum that are 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. All categories of Reserve volumes quoted herein have been determined within the context of an Economic Limit Test (ELT, pre-tax and exclusive of accumulated depreciation amounts) assessment prior to any Net Present Value (NPV) analysis.

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 reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

Prospective Resources are those quantities of petroleum that are 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 (the "Geological Chance of Success" (GCoS)) and a chance of development. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective Resource volumes presented herein are unrisked. Prospective Resources are risk assessed only in the context of identifying the stated GCoS. This dimension of risk assessment does not incorporate the considerations of economic uncertainty and commerciality.

Prospective Resources include Prospects and Leads. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered drillable. Leads, on the other hand, are not sufficiently well defined to be drillable, and need further work and/or data. In general, Leads are significantly more risky than Prospects and may not be suitable for explicit quantification.

Use of Net Present Values

The NPVs pertaining to each Reserves category and contained herein result from the application of assumptions of oil and gas prices applied to the volumes of oil and gas expected to be produced and sold, after taking into account the necessary capital and operating costs and other royalties, taxes and statutory deductions that may apply. It should be clearly noted that such NPVs do not represent a GCA opinion as to the market value of the subject property, nor any interest therein. In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e. that Reserves may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and the competitive state of the market at the time. GCA has explicitly not taken such factors into account for the purposes of this report.

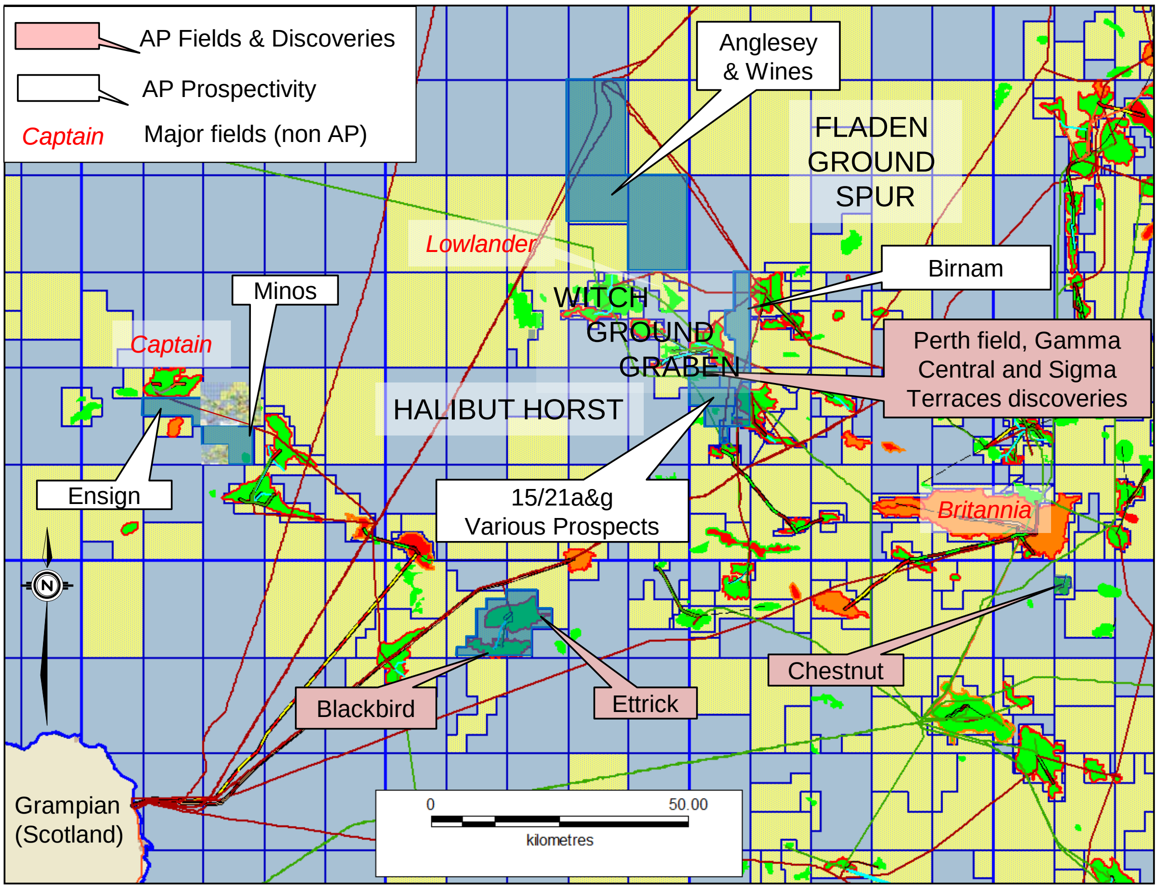
LICENCE SUMMARY

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 exploration and appraisal acreage in the UK and Ireland. In November, 2012, AP entered Norway through the acquisition of the Norwegian company Emergy Exploration AS. AP listed on the Nasdaq OMX in Iceland (2005), in Copenhagen (2007) and on the Oslo Børs (2013).

AP's UK North Sea assets can be divided into 5 groups: Moray Firth, Northern North Sea, Central North Sea, Southern North Sea and West of Shetland. AP's interests in the Moray Firth area are described in Table 0.1 and illustrated in the location map in Figure 0.1.

FIGURE 0.1

LOCATION OF AP LICENCES IN THE MORAY FIRTH AREA



Source: GCA after Deloitte

TABLE 0.1

AP LICENCES IN THE MORAY FIRTH AREA (UK) AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Ettrick	P273 & P317	20/2a & 20/3a	Field	Nexen (79.73)* Dana Petroleum Plc (12)	8.27	None	14/02/2015 (to be extended if still producing)
Blackbird (& Blackbird extension)[1]	P273, P317& P1580	20/2a, 20/3a & 20/3f	Field	Nexen (90.60227)*	9.39	None	01/11/2016
Chestnut	P354	22/2	Field	Centrica (69.875)*, KNOC (15.125)	15.00	None	16/12/2016
Perth	P588	15/21b & 5/21c	Discovery	Parkmead (52.13)* Faroe Petroleum (34.62)	13.35	Drill 13/21a-P1	31/12/2014
Sigma Terraces and Dolphin	P218	15/21b	Discovery	Parkmead (52.13)* Faroe Petroleum (34.62)	13.35	None	15/03/2018
Gamma Central/ Spaniards West	P218 & P1655	15/21a & 15/21f & 15/21g	Discovery	Premier Oil UK Ltd (28)*, Serica Energy (21), Cairn (21), Parkmead (12.624), Faroe Petroleum (8.4), Maersk Oil (5.736)	3.24	None	11/02/2017
Birnam & Kinross	P1993	15/16e	Discovery & Exploration	Parkmead (application as DEO) (34)*, Faroe Petroleum (33)	33.00	Seismic reprocessing. Drill or drop	31/12/2014
Minos	P1610	13/23a	Exploration	Dana/KNOC (45)*, Summit (25), Trap Oil (10)	20.00	none	11/2/2017
Ensign	P1766	13/22d	Exploration	Dana/KNOC (50)*, Summit (30)	20.00	Drill or drop	09/01/2015
Anglesey & Wines	P1767	14/9, 14/14a & 14/15	Exploration	Bridge Energy (70)*	30.00	Reprocess 100 km 3D or 150 km2 3D seismic. Drill to 2,500 m or drop	09/01/2015

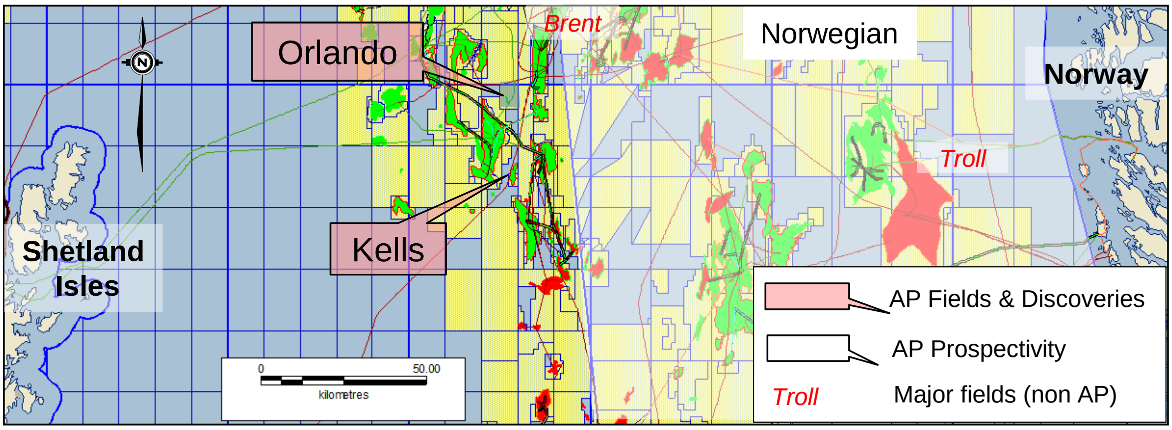
Note:

1. For P1580, Block 20/3f equities are Nexen Petroleum UK Ltd & Nexen Ettrick UK Ltd 79.73%, Korea National Oil Corporation (KNOC) 12% and AP 8.27% and the expiry date is 11/02/2017. Licence is partially relinquished.

AP has interests in two discoveries in the UK sector of the Northern North Sea. These assets are being developed. Orlando is a new development, and Kells (previously known as Staffa) is being redeveloped. Their locations are given in Figure 0.2. Both assets are operated by Iona, AP having the interest documented in Table 0.2.

FIGURE 0.2

LOCATION OF AP LICENCES IN UK SECTOR, NORTHERN NORTH SEA



Source: GCA after Deloitte

TABLE 0.2

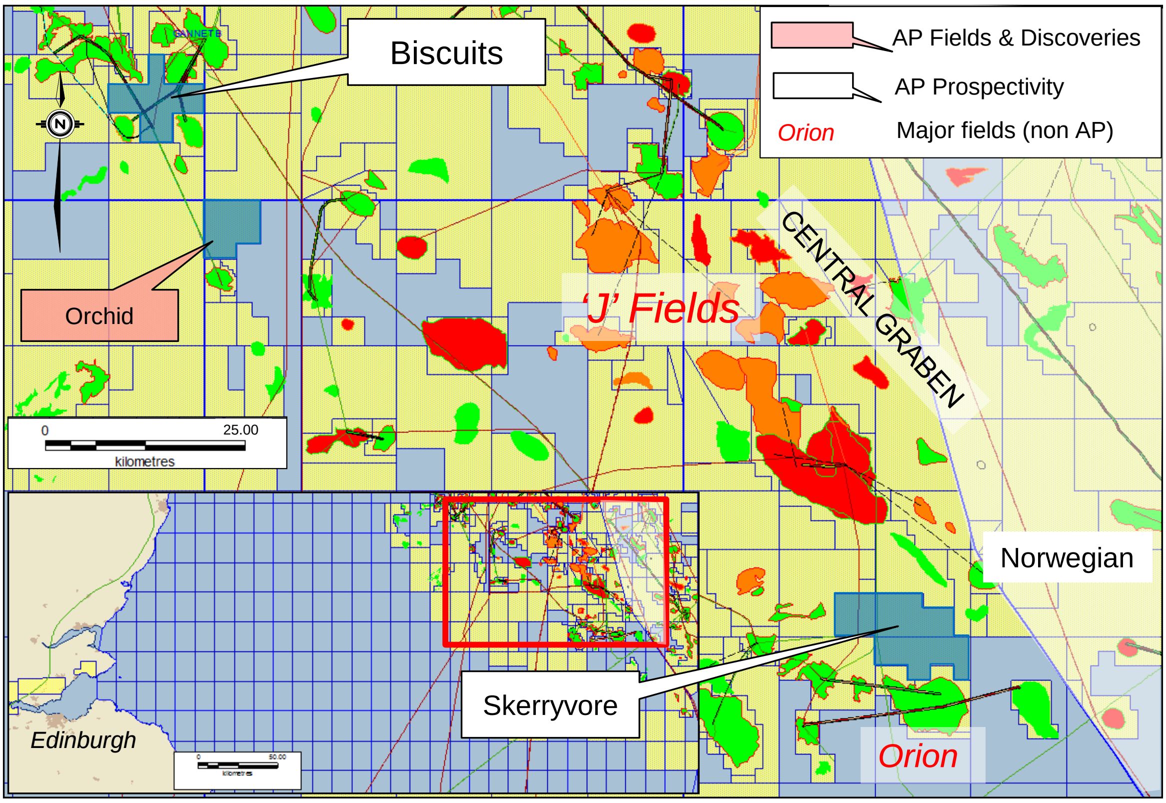
AP LICENCES IN UK SECTOR, NORTHERN NORTH SEA AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Orlando	P1606	3/3b	Field	Iona (75)*	25.00	None	11/02/2017
Kells	P1607	3/8b	Field	Iona (75)*	25.00	None (FDP to be Resubmitted to DECC)	11/02/2017

Within the area of the Central Graben of the North Sea, AP has interests in three licences, as shown in the Figure 0.3. Orchid is an existing discovery, Skerryvore and Biscuits are exploration assets as described in Table 0.3.

FIGURE 0.3

LOCATION OF AP LICENCES IN UK SECTOR, CENTRAL NORTH SEA



Source: GCA after Deloitte

TABLE 0.3

AP LICENCES IN UK SECTOR, CENTRAL NORTH SEA AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Orchid	P1556	29/1c	Discovery & Exploration	Trap Oil (60)* Valiant Exploration Ltd (30)	10.00	None	12/02/17
Skerryvore	P2082	30/12c, 30/13c, 30/18c	Exploration	Parkmead (30.5)* Bridge Energy (25) Dyas (14)	30.50	Firm well to 3,500 m TVDss or 200 m into Chalk, reprocessing, rock physics	31/12/16
Biscuits	P1791	21/30e	Exploration	Bridge Energy (40)* Idemitsu Petroleum (40)	20.00	None	Jan 2015

AP has interests in many assets in the UK sector of the Southern North Sea; both discoveries and exploration acreage. These can be considered as ten assets, although some licences contain multiple discoveries or prospects. The location of the assets and AP's interest are shown in Table 0.4 and Figure 0.4.

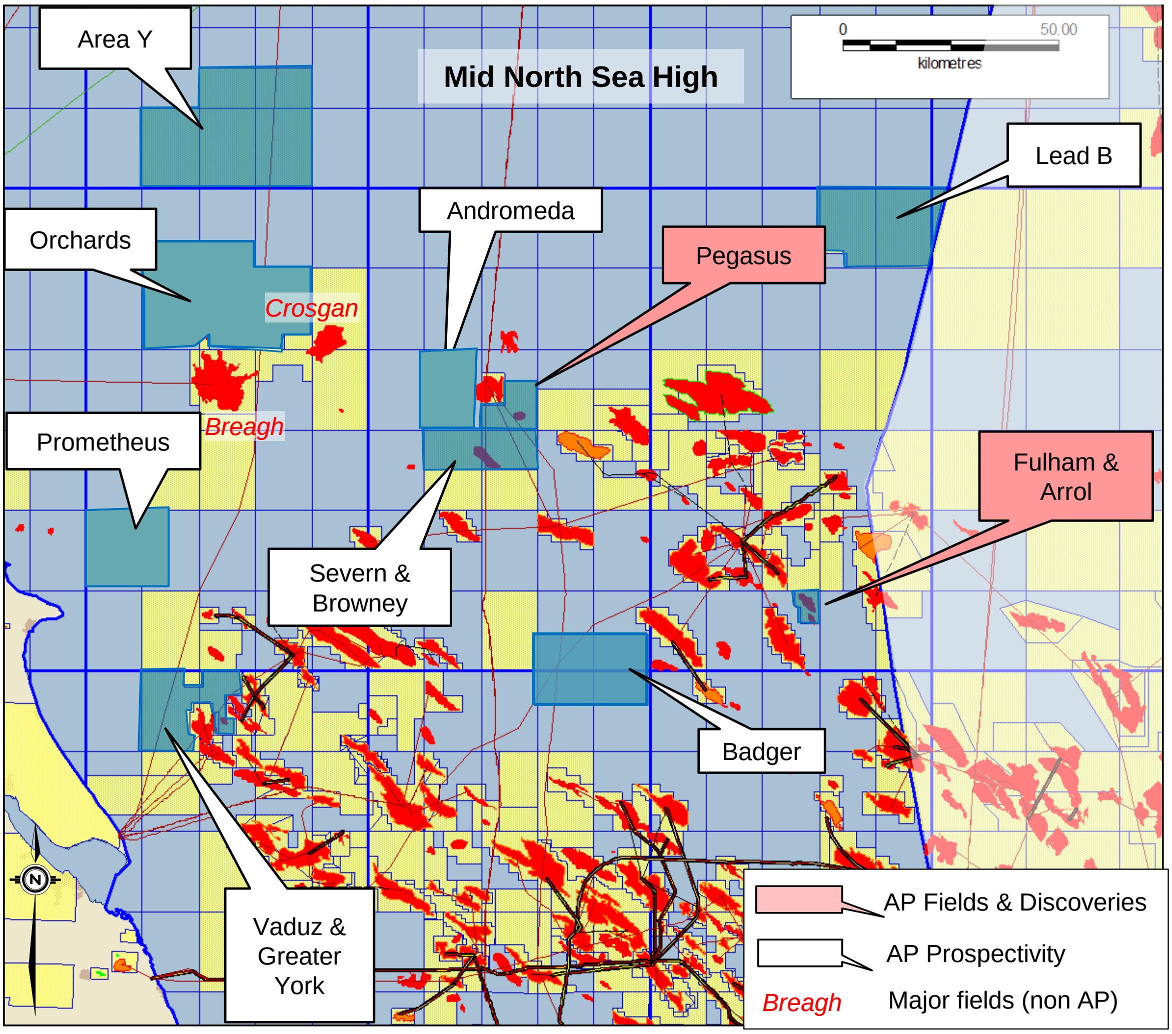
TABLE 0.4

AP LICENCES IN UK SECTOR, SOUTHERN NORTH SEA
AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Fulham & Arrol	P1673	44/28a	Discovery	Centrica (95)*	5.00	None	11/02/2017
Pegasus	P1724	43/13b	Discovery & Exploration	Centrica (55)* Viking UK Gas (Third Energy) (35)	10.00 (5% carry)	None	30/04/2018
Severn & Browney	P1727	43/17b, 43/18b	Exploration	Centrica (55)* Viking UK Gas (Third Energy) (35)	10.00 (5% carry)	Well by Apr 2014	30/04/2014
Greater York	P1906	47/2b, 47/3g 47/7a, 47/8d	Exploration	Centrica (52.5)* Serica (37.5)	10.00 (5% carry)	Reprocess 180 km^2, G&G	31/01/2016
Area Y	P1828	36/23a, 36/24a,36/27, 36/28 & 36/29	Exploration	Centrica (90)*	10.00 (5% carry)	G&G studies, Drill or drop in 4 years	09/01/2015
Lead B	P1899	44/4a, 44/5 & 45/1	Exploration	Centrica (45)* GDF (45)	10.00 (5% carry)	None	31/01/2016
Andromeda	P2128	43/12	Exploration	Centrica (90)*	10.00	Contingent well	19/12/2017
Orchards	P2126	42/2b, 42/3b, 42/7, 42/8b & 42/9b	Exploration	Centrica (45)* GdF Suez (45)	10.00	Contingent well, shoot 500 km^2 3D seismic	19/12/2017
Badger	P2112	43/29a, 43/30b, 48/4b & 48/5a	Exploration	Centrica (40)* Holywell (40)	20.00	Drill or drop, reprocess 87 km^2 3D seismic	19/12/2017
Prometheus	P2108	42/21 & 42/22a	Exploration	Centrica (90)*	10.00	Drill or drop, 350km new 2D seismic, biostrat study	19/12/2015

FIGURE 0.4

LOCATION OF AP LICENCES IN UK SECTOR, SOUTHERN NORTH SEA

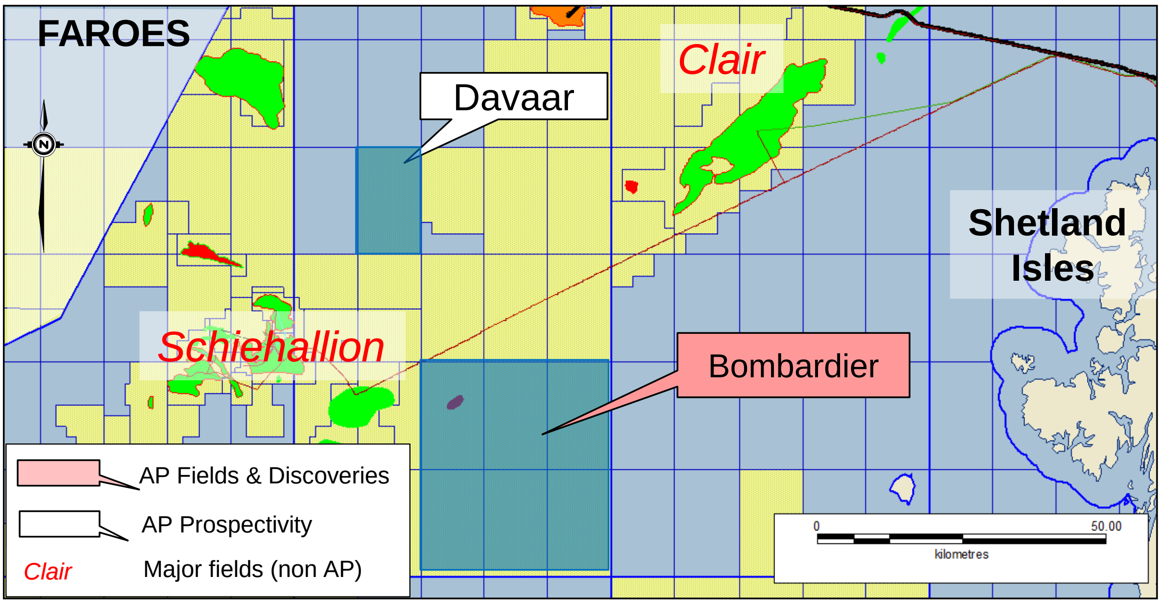


Source: GCA after Deloitte

AP also has interests in two licences in the UK sector of the Faroe-Shetland Basin, herein termed UK West of Shetland. Licence UK P1933 comprises Blocks 205/23, 205/24, 205/25, 205/28, 205/29 and 205/30 and contains the Bombardier discovery, the Eddystone Prospect and the Bell Rock Lead. Licence UKP2069 comprises Block 205/12 containing the Davaar Prospect. The location of the assets and AP's interest are shown in Figure 0.5 and Table 0.5.

FIGURE 0.5

LOCATION OF AP LICENCES IN THE UK WEST OF SHETLAND



Source: GCA after Deloitte

TABLE 0.5

AP LICENCES IN THE UK WEST OF SHETLAND AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Bombardier Eddystone & Bell Rock	P1933	205/23, 205/24, 205/25, 205/28, 205/29, 205/30	Discovery & Exploration	Parkmead (43)* Dyas (14)	43.00	Drill or drop, obtain 2D seismic studies	31/12/2018
Davaar	P2069	205/12	Exploration	Parkmead (30)* Summit (26) Dyas (14)	30.00	Drill or drop, reprocessing, studies	31/12/2016

Table 0.6 and Figure 0.6 show AP's interests in two licences in the Faroe Islands sector of the Faroe-Shetland Basin. Licence L006 comprises Blocks 6104/16a, 6104/21 and 6105/25 and contains the Brugdan Prospect. Licence L016 comprises multiple Blocks containing the Kúlubøkan Prospect.

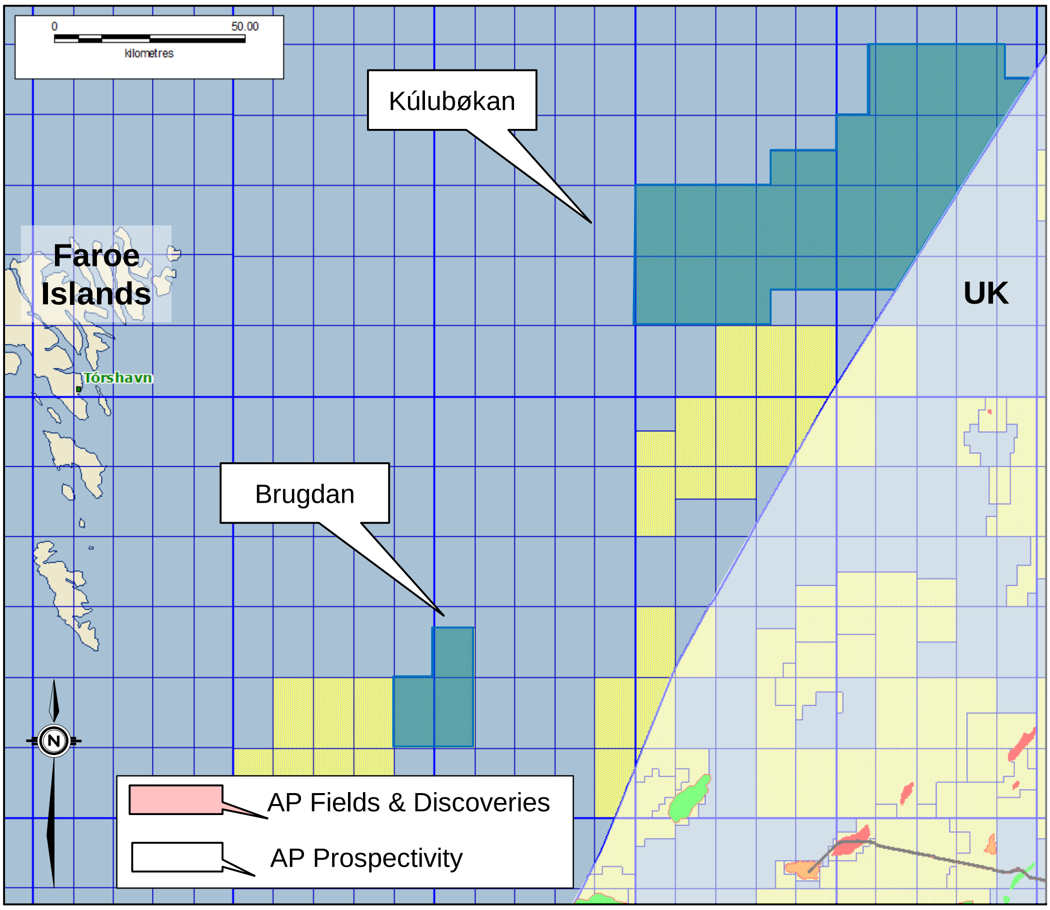
TABLE 0.6

AP LICENCES IN THE FAROE ISLANDS AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Brugdan	L006	6104/16a, 6104/21, 6105/25	Exploration	Statoil (50)* ExxonMobil (49)	1.00	1 well to Vaila Reservoir or 4,756 m ss whichever is shallower (re-entry in 2014)	07/12/2014
Kúlubøkan	L016	6202/6a, 6202/7-9, 6202/10a, 6202/11-18, 6202/21a, 6202/22a, 6203/14a, 6203/15a, 6203/16-23, 6203/24a, 6203/25a	Exploration	Statoil (40)* DONG (30) ExxonMobil (26)	4.00	None	08/12/2014

FIGURE 0.6

LOCATION OF AP LICENCES IN THE FAROE ISLANDS

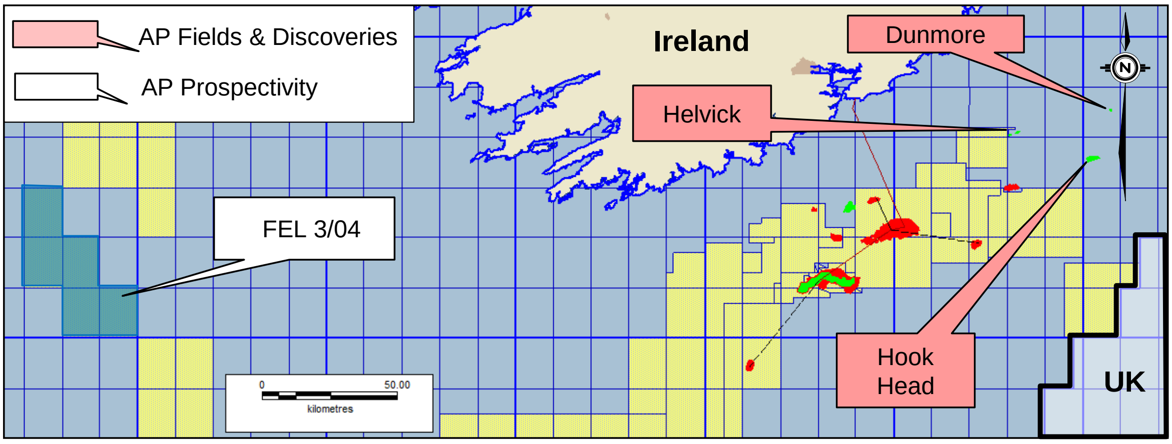


Source: GCA after Deloitte

AP's interests in Irish waters (see Figure 0.7), include four assets; three discoveries in the North Celtic Sea Basin and an exploration opportunity in the Porcupine Basin (Table 0.7).

FIGURE 0.7

LOCATION OF AP LICENCES IN IRELAND



Source: GCA after Deloitte

TABLE 0.7

AP LICENCES IN IRELAND
AS AT 31st DECEMBER, 2013

Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
SEL 2/07	50/11, 49/9, 50/6 & 50/7	Requested to convert to Lease Undertakings	Providence (72.5)*[1] Sosina (9.167)	18.33	None	31/01/2013[2]
FEL 3/04	44/18, 44/23, 44/24, 44/29, 44/30	Exploration	Exxon Mobil (25.5), ENI (27.5), Repsol (25), Providence (16), Sosina (2)	4.00	None	14/11/2013

Notes:

1. For Helvick only the partnership is: Providence (62.5%), AP (18.333%), Sosina (9.167%), Landsowne (10%).
2. An extension for FEL 3/04 has been requested in order to decide the next step based on the results of the well 44/23-1.

AP's interests in four blocks in Dutch waters, E1, E2, E4 and E5 are shown in Table 0.8 and Figure 0.8. These are all frontier exploration blocks clustered together against the international boundary line. Note that AP also has interests in adjacent blocks on the UK side of the international boundary, namely blocks 44/4a, 44/5 and 45/1 which form the UK licence P1899.

TABLE 0.8

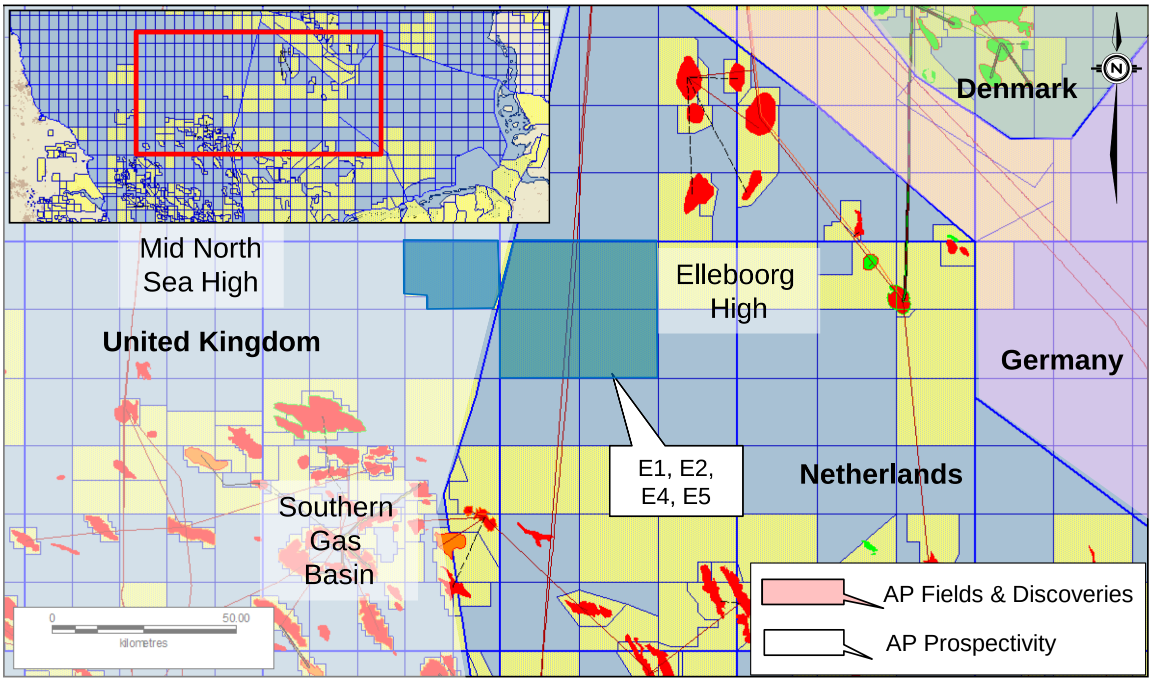
AP LICENCES IN THE NETHERLANDS
AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%)	AP Interest (%)	Outstanding Commitments	Expiry Date
Quad E	E1, E2, E4, E5	E1, E2, E3, E4	Exploration	Centrica (54) EBN (40)	6.00	Acquire long cable 3D (215 km^2 per block), acquire gravity/ magnetics. Drill or drop within 2 years	21/11/13

Note: A two year extension has been sought to allow for integration of new adjoining data. The application is still with the authorities.

FIGURE 0.8

LOCATION OF AP LICENCES IN THE NETHERLANDS

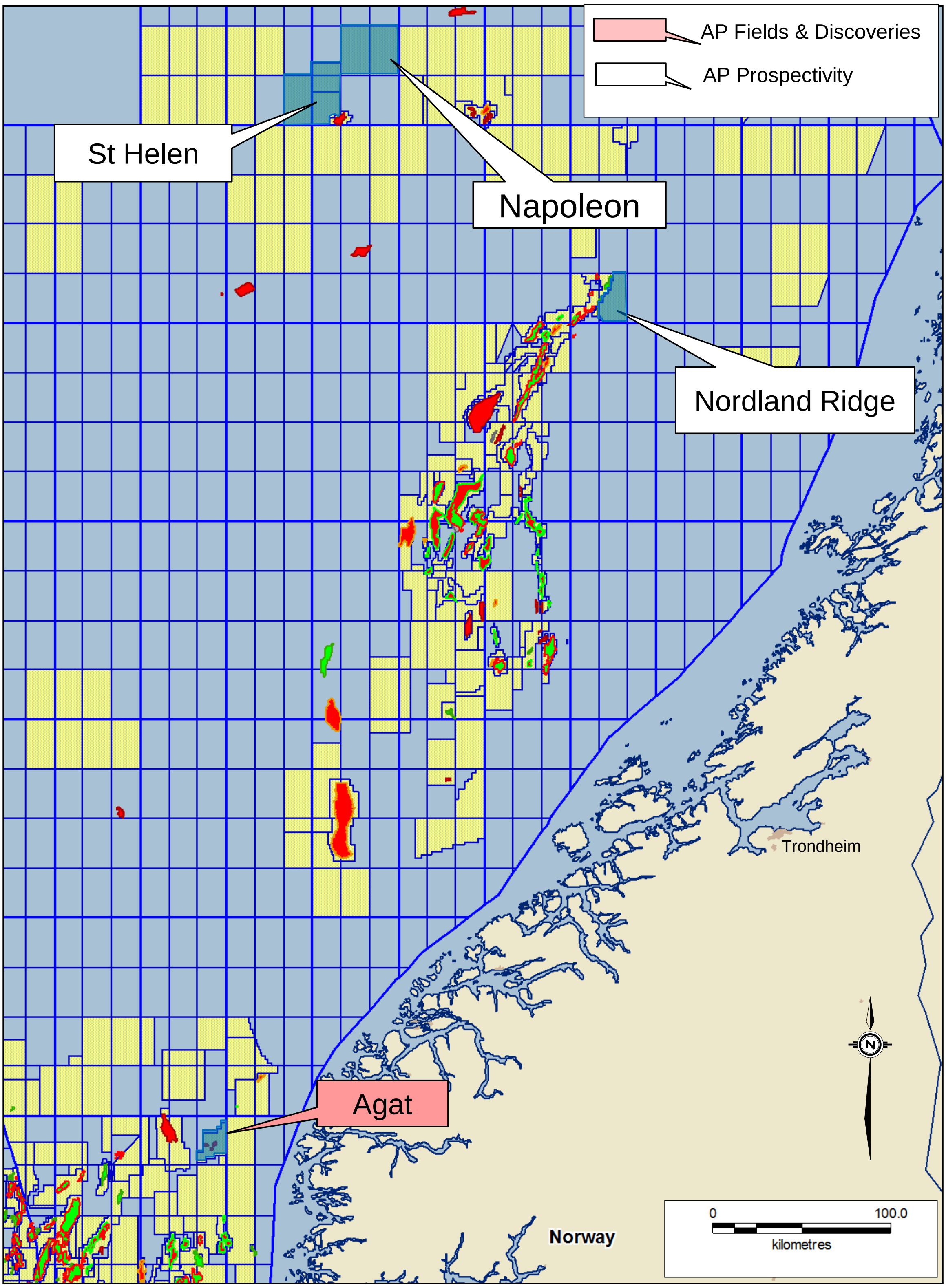


Source: GCA after Deloitte

AP's interests in four licences in Norway are shown in Table 0.9 and Figure 0.9. Licence PL270 is located at the northern end of the Maløy Slope in the Norwegian sector of the North Sea, comprises Block 35/3 and contains the Agat discovery and additional prospectivity. Licences PL559, PL704 and PL705 are located in the Norwegian Sea and contain multiple Prospects.

FIGURE 0.9

LOCATION OF AP LICENCES IN NORWAY



Source: GCA after Deloitte

TABLE 0.9

AP LICENCES IN NORWAY AS AT 31st DECEMBER, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Agat	PL270	35/3	Discovery & Exploration	VNG (85)*	15.00	Drill or drop in 2013, Potential new well in 2014, Decide possible development in 2014 after next well	2035
Nordland Ridge	PL559	6608/10 & 6608/11	Exploration	Rocksource (60)* VNG (20) Skagen 44 (10)	10.00	Plan for Development	19/02/16
St Helen	PL704	6704/12-1 & 6705/10 (part)	Exploration	Eon (40)* Repsol (30)	30.00	Years 1-2, Decide on 3D purchase or drop, Years 3-5 Drill exploration well	June, 2019
Napoleon	PL705	6705/7 (part), 6705/8-9, 6705/10 (part)	Exploration	Repsol (40)*, Eon (30)	30.00	Years 1-2 Acquire 3D seismic and decide to drill or drop, Years 5-7 Drill exploration well	June, 2019

RESERVES SUMMARY

The Proved, Proved plus Probable and Proved plus Probable plus Possible oil and gas Reserves attributed to AP's interests in the Ettrick, Blackbird, Chestnut, Orlando and Kells Fields as at 31st December, 2013 are summarised in Tables 0.10 and 0.11.

TABLE 0.10

OIL RESERVES AS AT 31st DECEMBER, 2013

Field	Gross Field (MMBbl)			WI (%)	Net to AP (MMBbl)		
	Proved	Proved plus Probable	Proved plus Probable plus Possible		Proved	Proved plus Probable	Proved plus Probable plus Possible
Ettrick	8.0	11.7	13.7	8.3	0.7	1.0	1.1
Blackbird	0.5	3.7	5.2	9.4	0.1	0.4	0.5
Chestnut	6.0	7.4	9.9	15.0	0.9	1.1	1.5
Orlando	7.8	15.4	21.6	25.0	2.0	3.8	5.4
Kells	1.9	4.2	5.2	25.0	0.5	1.1	1.3
Total	**24.2**	**42.4**	**55.6**		**4.1**	**7.4**	**9.8**

Notes:

1. The above Reserve volumes are reported after being subjected to an ELT.
2. Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 31st December, 2013 onwards.
3. Totals may not exactly equal the sum of the individual entries due to rounding

TABLE 0.11

GAS RESERVES
AS AT 31st DECEMBER, 2013

Field	Gross Field (Bscf)			WI (%)	Net to AP (Bscf)		
	Proved	Proved plus Probable	Proved plus Probable plus Possible		Proved	Proved plus Probable	Proved plus Probable plus Possible
Ettrick	4.8	7.1	8.3	8.3	0.4	0.6	0.7
Blackbird	0.3	1.8	2.6	9.4	0.0	0.2	0.2
Kells	19.7	27.5	33.1	25.0	4.9	6.9	8.3
Total	**24.8**	**36.4**	**44.0**		**5.3**	**7.7**	**9.2**

Notes:

1. The above Reserve volumes are reported after being subjected to an ELT.
2. Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 31st December, 2013 onwards.
3. Totals may not exactly equal the sum of the individual entries due to rounding

NET PRESENT VALUE SUMMARY

Reference post-tax NPVs have been attributed to the Proved, the Proved plus Probable and the Proved plus Probable plus Possible Reserves, at a discount rate of 10% (Table 0.12), based on GCA's first quarter 2014 price scenarios for Brent Crude and North Sea gas, and the applicable fiscal regime of the UK (Reserves are currently attributed only to properties in UK waters). All NPVs quoted are those attributable to AP's net entitlement interests in the properties reviewed.

GCA 1Q14 OIL AND GAS PRICE SCENARIOS

Year	Brent Price (US$/Bbl)	UK NBP Gas Price (pence/therm)
2014	108.80	63.56
2015	102.88	64.61
2016	97.05	63.17
2017	96.28	61.69
2018	97.42	60.26
2019	99.37	58.71
Thereafter	+2.0% p.a.	+2.0% p.a.

TABLE 0.12

POST-TAX NET PRESENT VALUES OF RESERVES, NET TO AP AT 10% DISCOUNT RATE (US$ MM), AS AT 31st DECEMBER, 2013

Field	Proved	Proved plus Probable	Proved plus Probable plus Possible	WI (%)
Ettrick	16.6	21.9	29.6	8.3
Blackbird	-0.2	9.1	14.0	9.4
Chestnut	18.0	20.9	24.3	15.0
Orlando	32.7	63.1	88.8	25.0
Kells	6.6	23.9	30.7	25.0
Total	**73.7**	**138.9**	**187.4**	

Notes:

1. The Net Present Values are calculated from discounted cash flows incorporating the fiscal terms governing each license block.
2. All cash flows are discounted on a mid-year basis to 31st December, 2013.
3. The values shown in this table are Net to AP.
4. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest in it.

CONTINGENT RESOURCES SUMMARY

The oil and gas Contingent Resources attributed to AP's interests, as at 31st December, 2013, are summarised in Tables 0.13 and 0.14 respectively.

TABLE 0.13

OIL CONTINGENT RESOURCES AS AT 31st DECEMBER, 2013

Area	Discovery	Gross (MMBbl)			WI (%)	Net to AP (MMBbl)		
		1C	2C	3C		1C	2C	3C
Moray Firth, UK	Perth	28.7	38.0	48.4	13.35	3.8	5.1	6.5
	NE Perth	6.8	13.0	21.3	13.35	0.9	1.7	2.8
	Bright	12.3	18.6	27.2	8.27	1.0	1.5	2.2
	Dolphin	2.0	6.0	14.0	13.35	0.3	0.8	1.9
	Spaniards	8.1	18.9	33.6	3.24	0.3	0.6	1.1
Central North Sea, UK	Orchid	4.0	5.0	8.0	10.00	0.4	0.5	0.8
North Celtic Sea, Ireland	Helvick	1.5	2.1	2.6	18.33	0.3	0.4	0.5
	Hook Head	25.2	35.0	47.2	18.33	4.6	6.4	8.6
	Coral/Dunmore	0.5	0.7	1.0	18.33	0.1	0.1	0.2
Total		**89.1**	**137.3**	**203.3**		**11.7**	**17.1**	**24.6**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the field in the event that it is developed, without any economic cut-off being applied.
2. The volumes reported here have not been adjusted to reflect the risks or uncertainties that may be associated with any future development.
3. Contingent Resources should not be aggregated with Reserves.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

TABLE 0.14

GAS CONTINGENT RESOURCES AS AT 31st DECEMBER, 2013

Area	Discovery	Gross (Bscf)			WI (%)	Net to AP (Bscf)		
		1C	2C	3C		1C	2C	3C
Southern North Sea, UK	Fulham & Arrol	17.0	42.0	63.0	5.0	0.9	2.1	3.2
	Pegasus North	30.1	103.7	310.1	10.0	3.0	10.4	31.0
Norway	NW Agat	5.2	14.6	39.7	15.0	0.8	2.2	6.0
	Bloody Basin	11.7	43.9	161.1	15.0	1.7	6.6	24.2
Total		**63.9**	**204.2**	**573.9**		**6.4**	**21.3**	**64.3**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the field in the event that it is developed, without any economic cut-off being applied.
2. The volumes reported here have not been adjusted to reflect the risks or uncertainties that may be associated with any future development.
3. Contingent Resources should not be aggregated with Reserves.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

PROSPECTIVE RESOURCES SUMMARY

Oil and gas Prospective Resources attributed to a number of undrilled Prospects, together with an estimated geological chance of success (GCoS), are summarised in Tables 0.15 and 0.16. Further, a significant number of Leads have been acknowledged in many of AP's licences areas. These are listed within the relevant sections of GCA's full report.

TABLE 0.15

OIL PROSPECTIVE RESOURCES (PROSPECTS) AS AT 31st DECEMBER, 2013

Area	Prospect	Gross (MMBbl)			WI (%)	Net to AP (MMBbl)			GCoS (%)
		Low	Best	High		Low	Best	High	
Moray Firth, UK	Perth NW Terrace	10.0	18.6	29.2	13.35	1.3	2.5	3.9	24
	Perth East	1.8	3.6	6.8	13.35	0.2	0.5	0.9	24
	Birnam	5.1	23.7	106.1	33.00	1.7	7.8	35.0	22
	Anglesey North	4.5	13.8	36.0	30.00	1.4	4.1	10.8	19
	Anglesey Central	5.8	27.9	80.0	30.00	1.7	8.4	24.0	19
	Anglesey South	3.3	9.3	23.6	30.00	1.0	2.8	7.1	19
	Chenas	2.5	7.8	25.2	30.00	0.8	2.3	7.6	17
	Brouilly	4.5	11.1	29.2	30.00	1.4	3.3	8.8	17
	Morgon	1.3	4.2	14.4	30.00	0.4	1.3	4.3	17
	Fleurie	3.5	8.7	24.0	30.00	1.1	2.6	7.2	17
Central North Sea, UK	Orchid West	4.0	8.1	17.2	10.00	0.4	0.8	1.7	40
	Skerryvore	9.0	16.0	27.0	30.50	2.7	4.9	8.2	26
	Skerryvore Chalk	31.0	66.0	119.0	30.50	9.5	20.1	36.3	30
West of Shetland, UK	Eddystone	71.0	166.0	328.0	43.00	30.5	71.4	141.0	9
	Davaar	75.0	159.0	285.0	30.00	22.5	47.7	85.5	15
Norway	Hendricks	64.0	132.0	233.0	10.00	6.4	13.2	23.3	18
Ireland	Dunquin South	58.1	363.4	959.2	4.00	2.3	14.5	38.4	12

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered viable drilling targets.
2. Gross Prospective Resources are 100% of the volumes estimated to be recoverable from the Prospect in the event that a discovery is made and subsequently developed.
3. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery.
4. The Low, Best and High Prospective Resource volumes for each prospect represent the range expected in the event of a discovery, and have not been adjusted in any way to reflect GCoS (exploratory risk).
5. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.

TABLE 0.16

**GAS PROSPECTIVE RESOURCES (PROSPECTS)
AS AT 31st DECEMBER, 2013**

Area	Prospect	Gross(Bscf)			WI (%)	Net To AP (Bscf)			GCoS (%)
		Low	Best	High		Low	Best	High	
Southern North Sea, UK	Pegasus West	39.0	135.6	447.3	10.0	3.9	13.6	44.7	45
	Pegasus South/ East	11.0	34.2	100.1	10.0	1.1	3.4	10.0	39
	Andromeda North	13.3	38.0	81.3	10.0	1.3	3.8	8.1	27
	Andromeda South	12.4	32.8	67.8	10.0	1.2	3.3	6.8	27
	Aurora	190.6	802.3	3,001.9	10.0	19.1	80.2	300.2	18
	Prometheus	15.2	75.0	325.4	10.0	1.5	7.5	32.5	60
Faroe Islands	Brugdan	1,134.9	3,481.3	8,448.5	1.0	11.3	34.8	84.5	15
	Kúlubøkan	1,300.0	4,400.0	13,500.0	4.0	52.0	176.0	540.0	11
Southern North Sea, Netherlands	Maes	13.1	65.0	280.8	6.0	0.8	3.9	16.8	21
	Hals	9.8	50.0	224.9	6.0	0.6	3.0	13.5	14
	Metsu	5.6	21.0	61.1	6.0	0.3	1.3	3.7	21
	Van Goyen	8.8	28.5	70.9	6.0	0.5	1.7	4.3	19
	Cuyp	13.3	73.0	365.3	6.0	0.8	4.4	21.9	25
Norway	Agat (Turitella)	15.4	66.8	280.8	15.0	2.3	10.0	42.1	52
	Napoleon North	146.7	370.5	772.7	30.0	44.0	111.2	231.8	28
	Napoleon South	117.2	282.7	554.9	30.0	35.2	84.8	166.5	28

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered viable drilling targets.
2. Gross Prospective Resources are 100% of the volumes estimated to be recoverable from the Prospect in the event that a discovery is made and subsequently developed.
3. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery.
4. The Low, Best and High Prospective Resource volumes for each prospect represent the range expected in the event of a discovery, and have not been adjusted in any way to reflect GCoS (exploratory risk).
5. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.

QUALIFICATIONS

GCA is an independent international energy advisory group of more than 50 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

The report was prepared by GCA staff under the supervision of Dr. Me'ad Hussain. Dr. Hussain is a Senior Advisor in Reservoir Engineering with 28 years' industry experience. She has a Ph.D. and M.Sc in Petroleum Engineering from Heriot Watt University and is a member of the Society of Petroleum Engineers and a Chartered Engineer of the Energy Institute.

Gaffney, Cline & Associates

The ultimate signatory of the report is Dr. John Barker, Technical Director, Reservoir Engineering, who has 29 years' industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

Yours sincerely,
GAFFNEY, CLINE & ASSOCIATES

John Barker

John Barker
Technical Director – Reservoir Engineering

APPENDIX I

Abbreviated form of SPE PRMS

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

March 2007

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 management 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 definition 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 document 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 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 PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

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 5 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.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity’s assumptions of future prices, costs, etc. (“forecast case”) and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project “decision gate” 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.

Proved Reserves

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

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

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

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

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

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

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. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

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

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

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,

(2) wells which were shut-in for market conditions or pipeline connections, or

(3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion 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.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,

(2) from deepening existing wells to a different (but known) reservoir,

(3) from infill wells that will increase recovery, or

(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to

(a) recomplete an existing well or

(b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

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.

Development Pending

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 reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

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. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

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 recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

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.

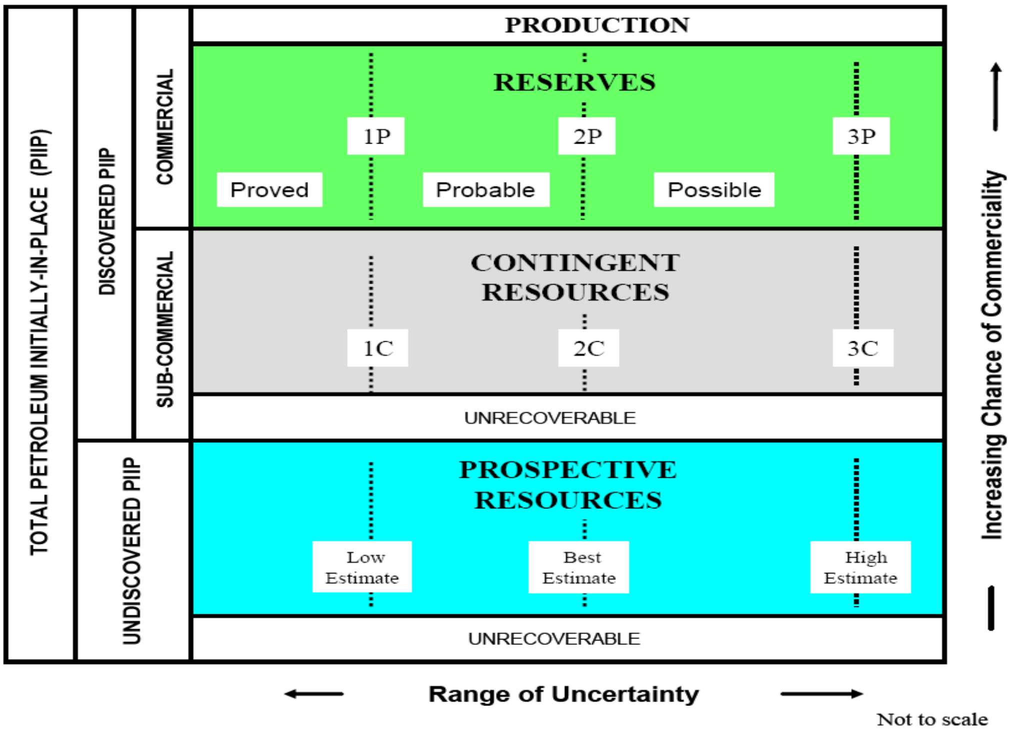
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under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

Play

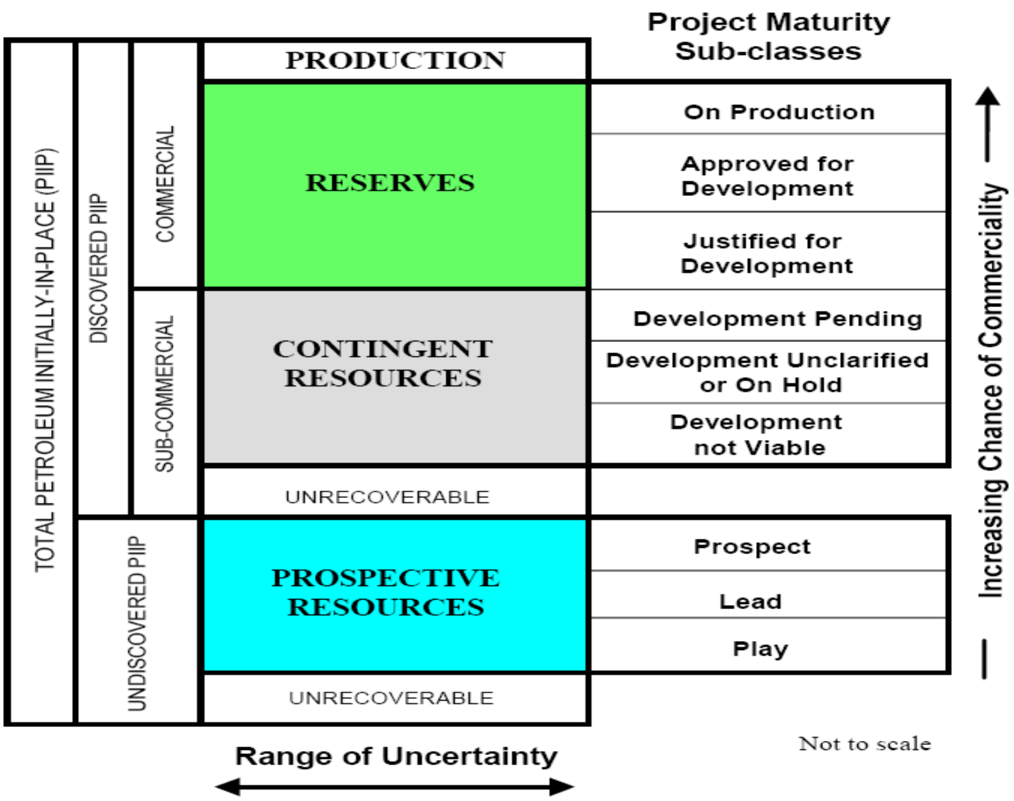
A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

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.

RESOURCES CLASSIFICATION



PROJECT MATURITY



APPENDIX II

Glossary

Gaffney, Cline & Associates

GLOSSARY
List of Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
^{o}API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement Interest
EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production, Storage and Offloading
FSO	Floating Storage and Offloading
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs

Gaffney, Cline & Associates

G&G	Geology & Geophysics
GBP	Pounds Sterling
GDT	Gas Down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOR	Gas Oil Ratio
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)
Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
NBP	National Balancing Point (UK)
NGL	Natural Gas Liquids
N_2	Nitrogen
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting

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ODT	Oil down to
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
PI	Productivity Index
PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure volume temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
Rf	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
S_o	Oil Saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
ss	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
S_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
TWT	Two Way Time
USGS	United States Geological Survey
US$	United States Dollar
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
1H05	First half (6 months) of 2005 (example of date)
2Q06	Second quarter (3 months) of 2006 (example of date)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
%	Percentage