Gaffney, Cline & Associates

SUMMARY VERSION OF THE COMPETENT PERSON'S REPORT ON ATLANTIC PETROLEUM INTERESTS AS AT 31st DECEMBER, 2014

Prepared for

ATLANTIC PETROLEUM P/F

MARCH, 2015

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Gaffney, Cline & Associates

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MIH/kab/EL-14-217000/0668 **12th March, 2015**

The Directors,
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SUMMARY VERSION OF THE COMPETENT PERSON'S REPORT ON ATLANTIC PETROLEUM INTERESTS AS AT 31st DECEMBER, 2014

INTRODUCTION

Atlantic Petroleum P/F (AP) requested Gaffney, Cline & Associates (GCA) to provide an independent technical and economic assessment of the oil and gas Reserves and Resources, and the Net Present Value (NPV) of the Reserves, in its assets in UK, Irish and Norwegian waters, in the form of a Competent Person's Report (CPR) with an effective date of 31st December, 2014. 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.

This report relates specifically and solely to the subject matter as defined in the scope of work in the Proposal for Services and is conditional upon the assumptions described herein. The report must be considered in its entirety and must only be used for the purpose for which it was intended.

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 must be considered in its entirety. It 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 work.

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 may include, for example, projects for which there are currently no evident 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.

It must be appreciated that the 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 and a chance of development. Prospective Resources 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.

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 are presented as unrisked. It must be appreciated that Prospective Resources are risk assessed only in the context of identifying the stated 'Geological Chance of Success', a percentage which pertains to the percentage probability of achieving the status of a Contingent Resource (where the Geological Chance of Success is unity). 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

It should be clearly understood that the NPVs of future revenue potential of a petroleum property, such as those discussed in this report, do not represent GCA's opinion as to the market value of that 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 realised 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 in deriving the reference NPVs presented herein.

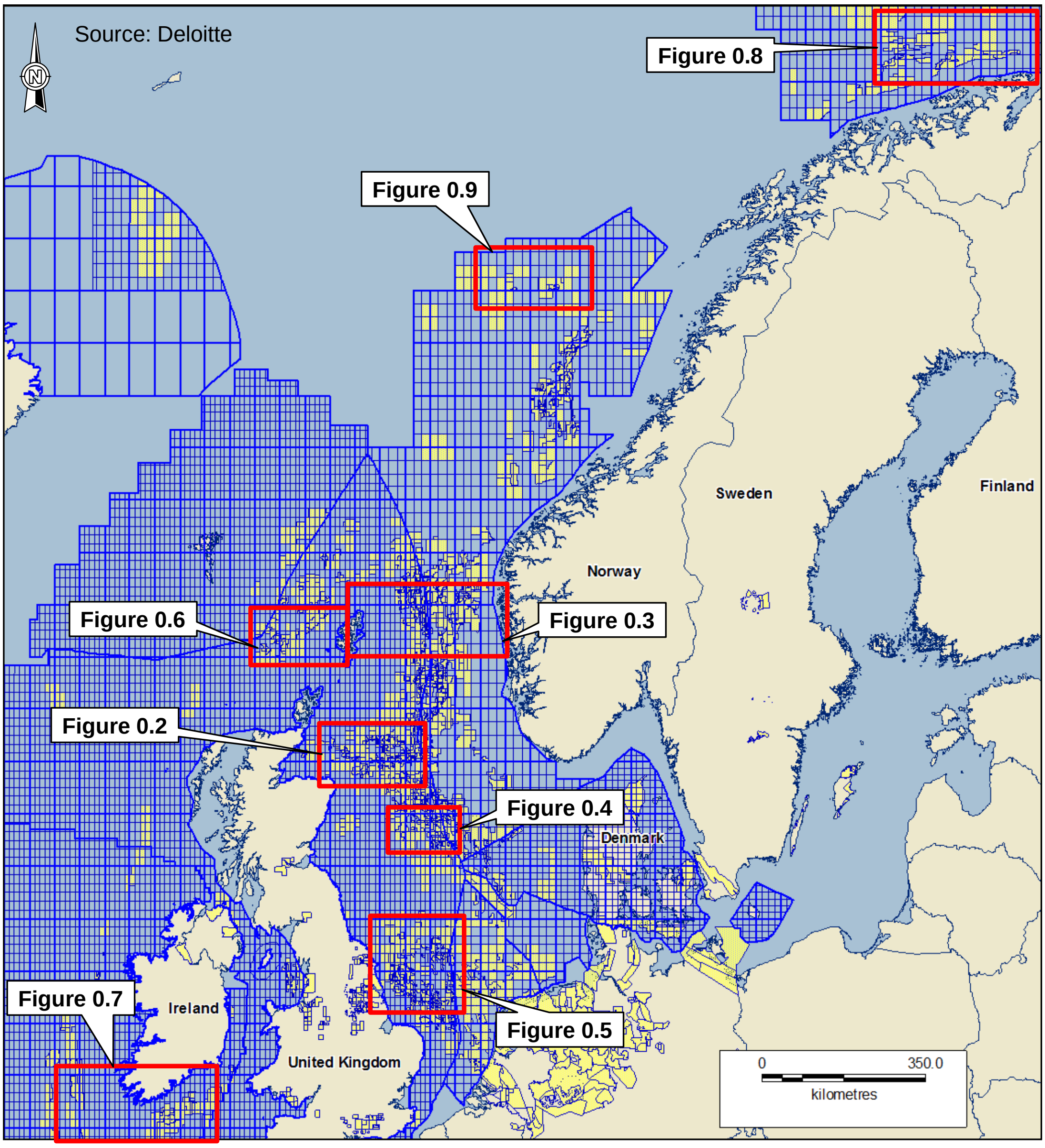
LICENCE SUMMARY

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). During 2014, AP divested its Netherlands and Faroe Islands assets, retaining interests in the UK, Ireland and Norway.

AP's UK assets can be divided into 5 groups: Moray Firth, Northern North Sea, Central North Sea, Southern North Sea and West of Shetland (Figure 0.1).

FIGURE 0.1

LOCATION MAP – ALL AP ASSETS



AP's interests in the Moray Firth area are described in Table 0.1 and illustrated in the location map in Figure 0.2. Licences P1993, P1766 and P1767 are not tabulated as they were held through 2014 but were either relinquished late December, 2014 (P1993) or are to be relinquished on 9th January, 2015 (P1766 and P1767). The partners in P1993 have decided to seek an extension to this licence, but AP will not be participating in any extension granted.

TABLE 0.1

AP LICENCES IN THE MORAY FIRTH AREA (UK)
AS AT 31st DECEMBER, 2014

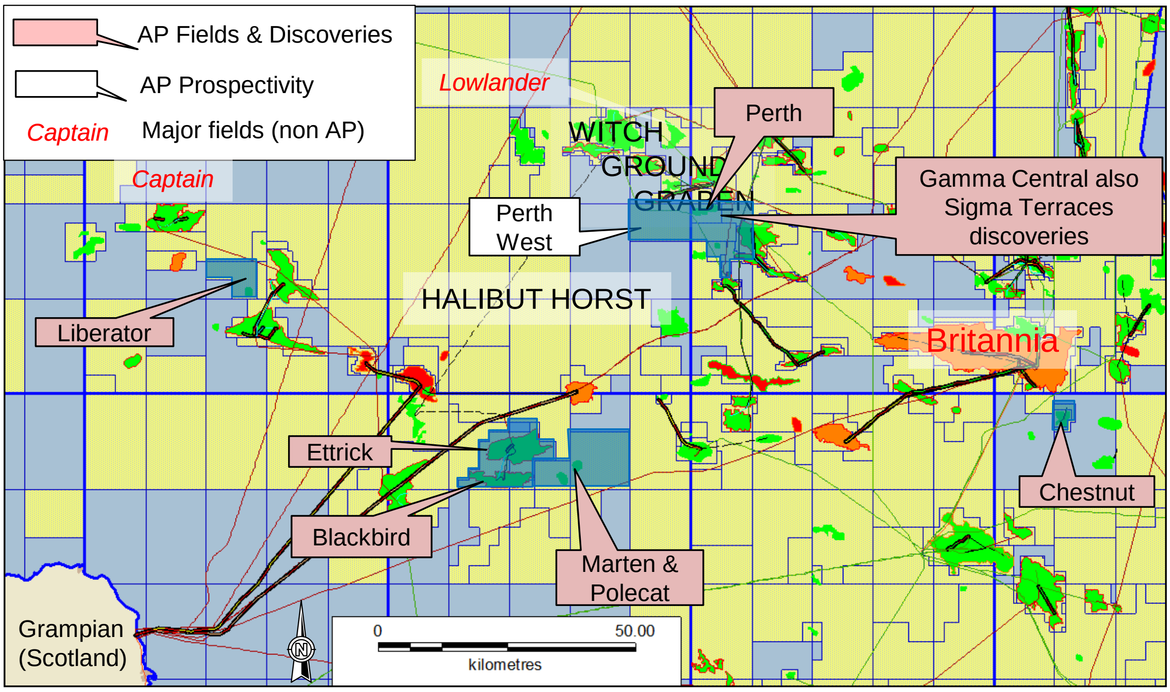
Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Ettrick	P273 & P317	20/2a & 20/3a	Field	Nexen (79.73)* KNOC (12.00)	8.27	None	14/02/2015 (but not if still producing)
Blackbird (& Blackbird extension)[1]	P273, P317& P1580	20/2a, 20/3a & 20/3f	Field	Nexen (90.60)*	9.39	None	01/11/2016
Chestnut	P354	22/2a	Field	Centrica (69.88)*, KNOC (15.13)	15.00	None	16/12/2016
Perth	P588	15/21b & 5/21c	Discovery	Parkmead (52.03)* Faroe Petroleum (34.62)	13.35	None	03/06/2023
Perth West	P2154	14/25a	Exploration	Parkmead (52.03)* Faroe Petroleum (34.62)	13.35	Obtain PSDM. Drill or drop to 3,800 m or 500 m below BCU	30/11/2017
Sigma Terraces and Dolphin[2]	P218	15/21a&f	Discovery	Parkmead (52.03)* Faroe Petroleum (34.62)	13.35	None	15/03/2018
Gamma Central/ Spaniards West[2]	P218 & P1655	15/21a Gamma subarea & g	Discovery	MOL (28.00)*, Serica Energy (21.00), Cairn (21.00), Parkmead (12.62), Faroe Petroleum (8.40, Maersk Oil (5.74)	3.24	None	11/02/2017
Liberator	P1610	13/23a	Discovery	Dana/KNOC (45.00)*, Summit (25.00), Trap Oil (10.00)	20.00	none	11/2/2017
Marten & Polecat	P2218	20/3c & 20/4a	Discovery	Parkmead (50.00)*	50.00	FDP or drop	30/11/2018

Notes:

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.
2. Interests have been rounded to two decimal places.

FIGURE 0.2

LOCATION OF AP LICENCES IN THE MORAY FIRTH AREA

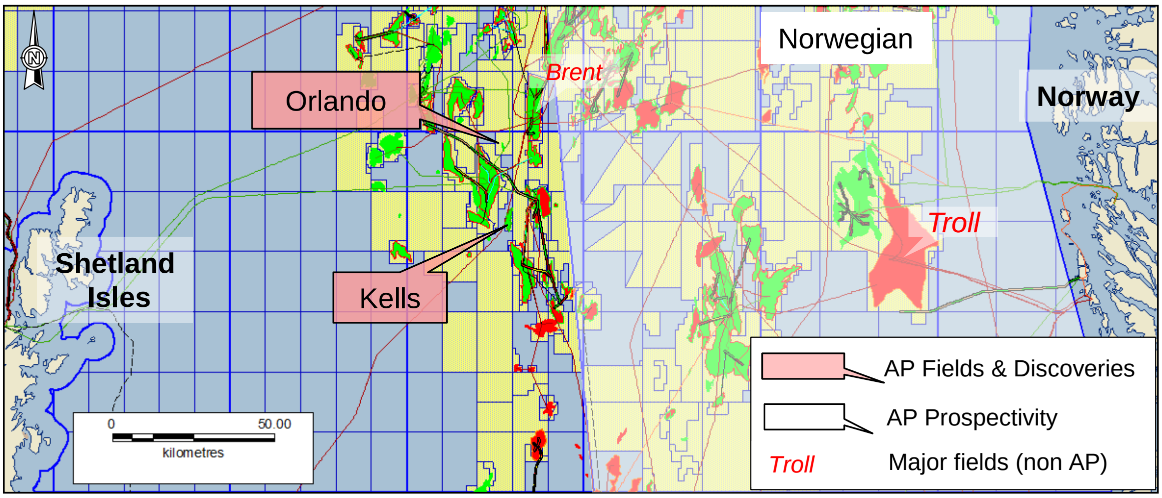


Source: GCA after Deloitte

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 0.3. Both assets are operated by Iona, AP having the interest documented in Table 0.2.

FIGURE 0.3

LOCATION OF AP LICENCES IN UK SECTOR, NORTHERN NORTH SEA



Source: GCA after Deloitte

TABLE 0.2

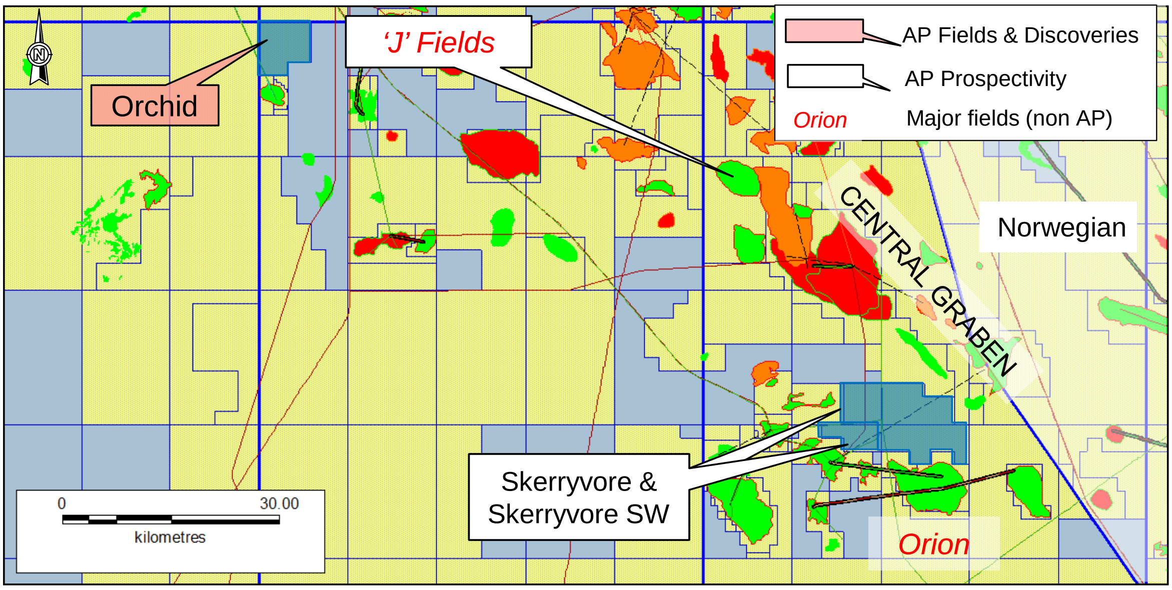
AP LICENCES IN UK SECTOR, NORTHERN NORTH SEA AS AT 31st DECEMBER, 2014

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Orlando	P1606	3/3b	Field	Iona (75)*	25.00	None (will go to production)	11/02/2017
Kells	P1607	3/8b	Field	Iona (75)*	25.00	None (FDP to be Resubmitted to DECC)	11/08/2015

Within the area of the Central Graben of the North Sea, AP has interests in three licences, as shown in Figure 0.4 and described in Table 0.3. Orchid is an existing discovery. The Skerryvore licences are exploration licences.

FIGURE 0.4

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, 2014

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Orchid	P1556	29/1c	Discovery & Exploration	Trap Oil (86)*	14.00	None	11/02/2017
Skerryvore	P2082	30/12c, 30/13c, 30/18c	Exploration	Parkmead (30.5)* Verus Petroleum (25) Dyas (14)	30.50	Firm well to 3,500 m TVDss or 200 m into Chalk, reprocessing, rock physics	31/12/2016
Skerryvore SW	NA	30/17e	Exploration	Parkmead (30.5)* Verus Petroleum (25) Dyas (14)	30.50	Seismic reprocessing and drill or drop to 3,500 m TVDss or 200 m into Chalk	30/11/2018

AP has interests in eight assets in the UK sector of the Southern North Sea, which include multiple discoveries and exploration prospects. The location of the assets and AP's interest are shown in Table 0.4 and Figure 0.5.

TABLE 0.4

AP LICENCES IN UK SECTOR, SOUTHERN NORTH SEA AS AT 31st DECEMBER, 2014

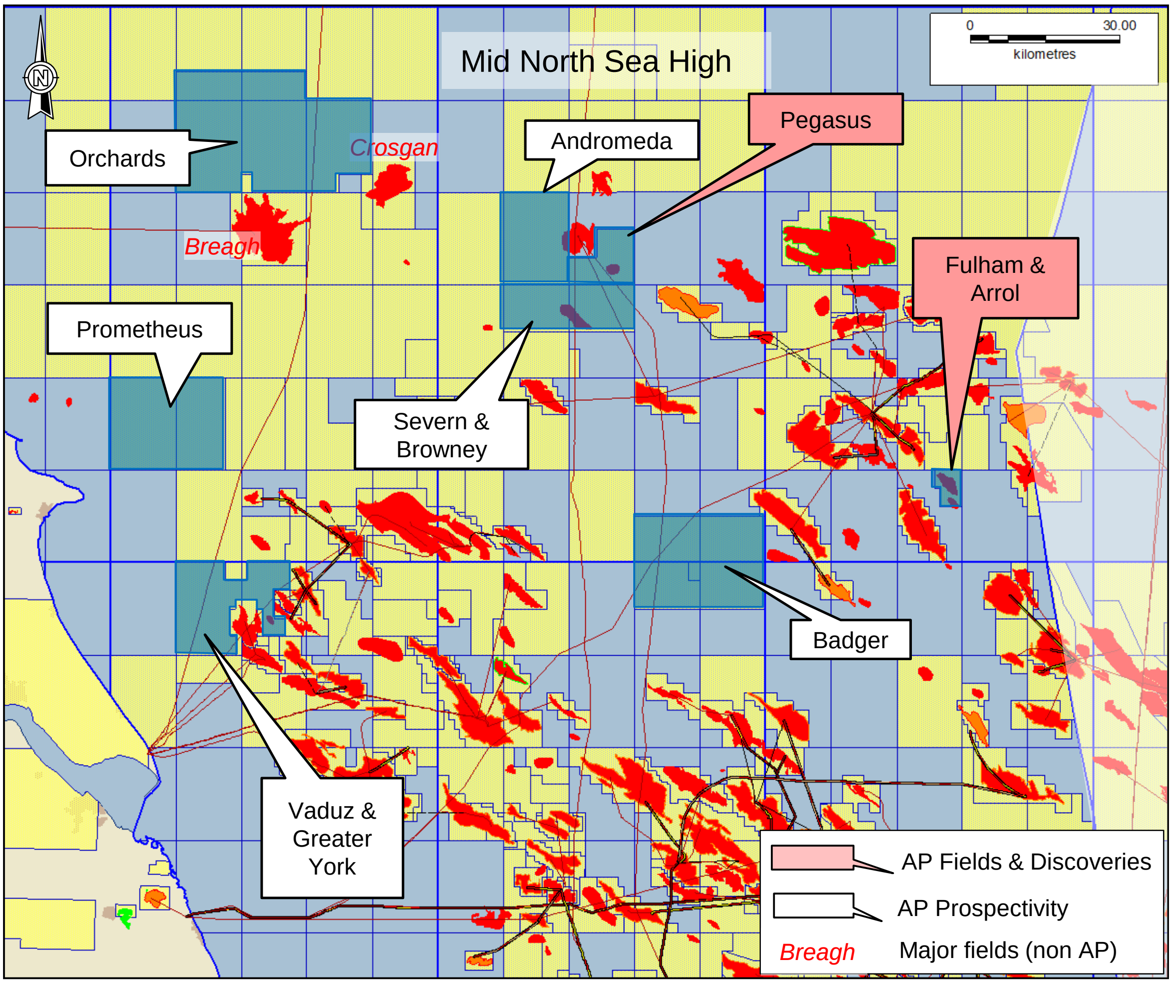
Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Fulham & Arrol	P1673	44/28a	Discovery	Centrica (95)*	5.00	None	11/02/2017
Pegasus	P1724	43/13b	Discovery & Exploration	Centrica (55)* Third Energy (35)	10.00 (5% carry)[1]	None	30/04/2018
Severn & Browney	P1727	43/17b, 43/18b	Exploration	Centrica (55)* Third Energy (35)	10.00 (5% carry)	None	30/04/2018
Greater York	P1906	47/2b, 47/3g 47/7a, 47/8d	Exploration	Centrica (52.5)* Serica (37.5)	10.00 (5% carry)	160 km^2 new 3D, Reprocess 180 km^2, G&G Drill or drop	31/01/2016
Andromeda	P2128	43/12	Exploration	Centrica (55)* Third Energy Offshore Limited (35)	10.00	Contingent well (based on results of Pegasus West)	19/12/2017
Orchards	P2216	42/2b, 43/3b, 42/7, 42/8b & 42/9b	Exploration	Centrica (45)* GdF Suez (45)	10.00	Contingent well based on closure of structure to north	19/12/2017
Badger (& Badger Core)	P2112	43/29a, 43/30b, 48/4a & b, & 48/5a	Exploration	Centrica (40)* Holywell (40)	20.00	Drill or drop, reprocess 78 km^2 PGS MegaMerge to PSDM	19/12/2017
Prometheus	P2108	42/21 & 42/22a	Exploration	Centrica (80)*	20.00	Drill or drop, 240 km new 2D seismic, biostrat study	19/12/2017

Note:

1. AP had a 5% carry in the first well, which was Pegasus North.

FIGURE 0.5

**LOCATION OF AP LICENCES IN UK SECTOR,
SOUTHERN NORTH SEA**

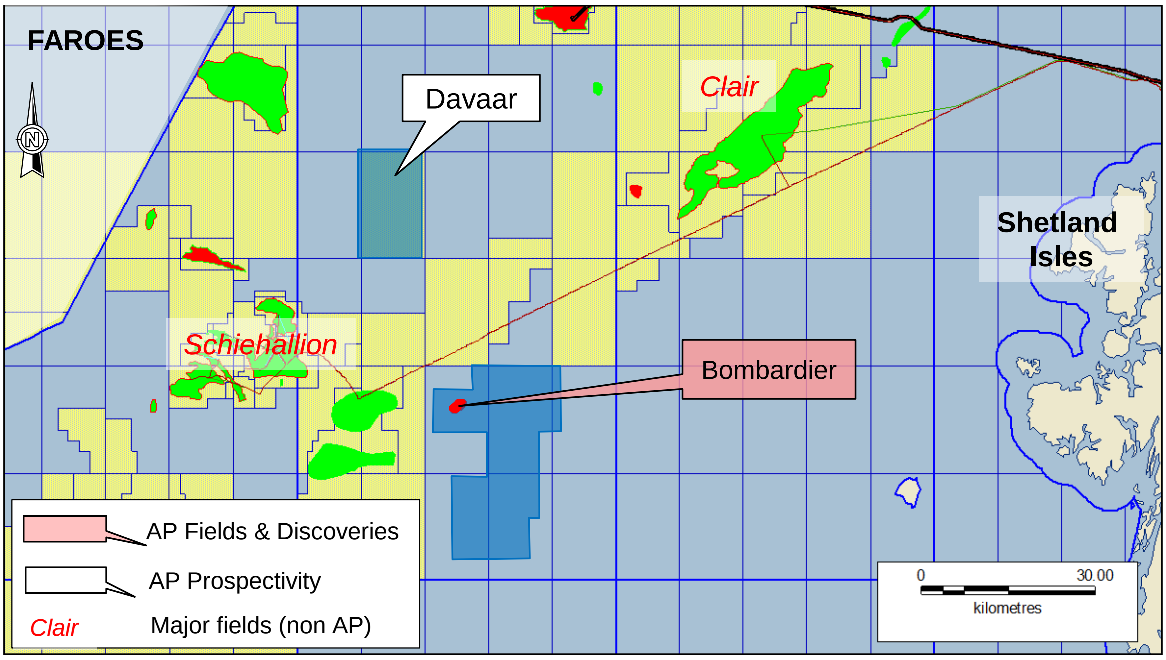


Source: GCA after Deloitte

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 205/23a, 205/24a, 205/25a, 205/28a and 205/29a and contains the Bombardier discovery and the Eddystone Prospect. Licence UK P2069 comprises Block 205/12 containing the Davaar Prospect. The location of the assets and AP's interest are shown in Figure 0.6 and Table 0.5.

FIGURE 0.6

LOCATION OF AP LICENCES IN THE UK WEST OF SHETLAND



Source: GCA after Deloitte

TABLE 0.5

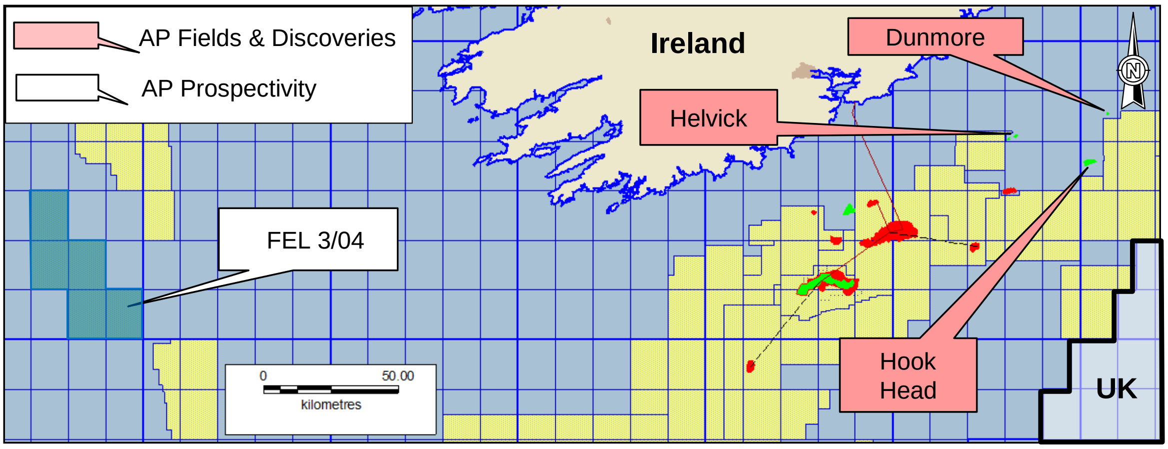
AP LICENCES IN THE UK WEST OF SHETLAND
AS AT 31st DECEMBER, 2014

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Bombardier	P1933	205/23a, 205/24a, 205/25a, 205/28a, 205/29a	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)* Production Limited (26), Dyas (14)	30.00	Drill or drop, reprocessing, studies	31/12/2016

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 0.6).

FIGURE 0.7

LOCATION OF AP LICENCES IN IRELAND



Source: GCA after Deloitte

TABLE 0.6

AP LICENCES IN IRELAND
AS AT 31st DECEMBER, 2014

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	14/11/2015[2]
FEL 3/04	44/18, 44/23, 44/24, 44/29, 44/30	Exploration	ENI* (36.913), Repsol (33.557), Providence (21.477), Sosina (2.684)	5.37	None	14/11/2013[3]

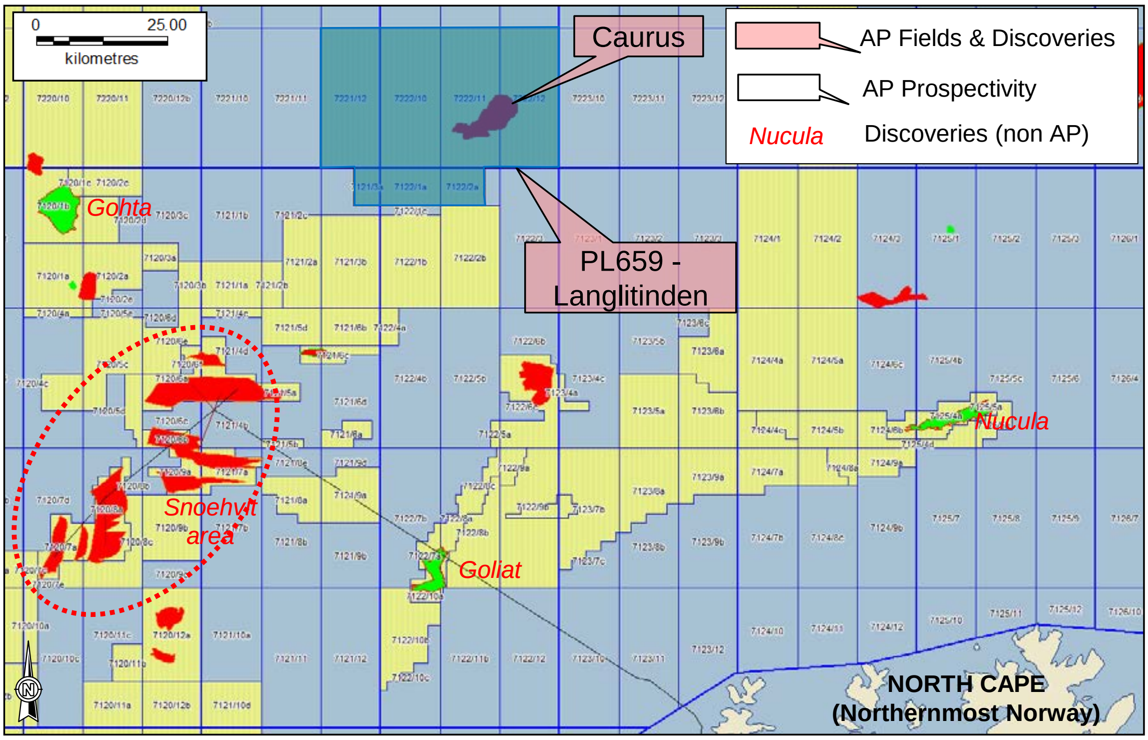
Notes:

1. Equities shown for Hook Head and Dunmore. For Helvick only the partnership is: Providence (62.5%), AP (18.333%), Sosina (9.167%), Landsowne (10%).
2. The partners are awaiting the government's decision on conversion to Lease Undertaking. Further materials were requested by PAD and supplied in October, 2014.
3. An extension for FEL 3/04 has been requested and approved by the PAD.
4. Interests have been rounded to two decimal places.

AP has interests in six exploration licences in Norway, all within the Arctic Circle. Five of these licences are clustered in the Vøring Basin area of the Norwegian Sea. The sixth licence (Langlitinden) is off the northernmost coast of Norway, in the Barents Sea. The location of the assets and AP's interest are shown in more detail in Figures 0.8 and 0.9, and Table 0.7. AP entered into four of these licences during 2014 (Licences PL 659, 528 (& 528B), 763 and 602). The remaining two licences, PL704 and PL705, were awarded to AP and its partners in June, 2013. Two further licences (PL270 (Agat) and PL 559 (Nordland Ridge)) were relinquished during 2014.

FIGURE 0.8

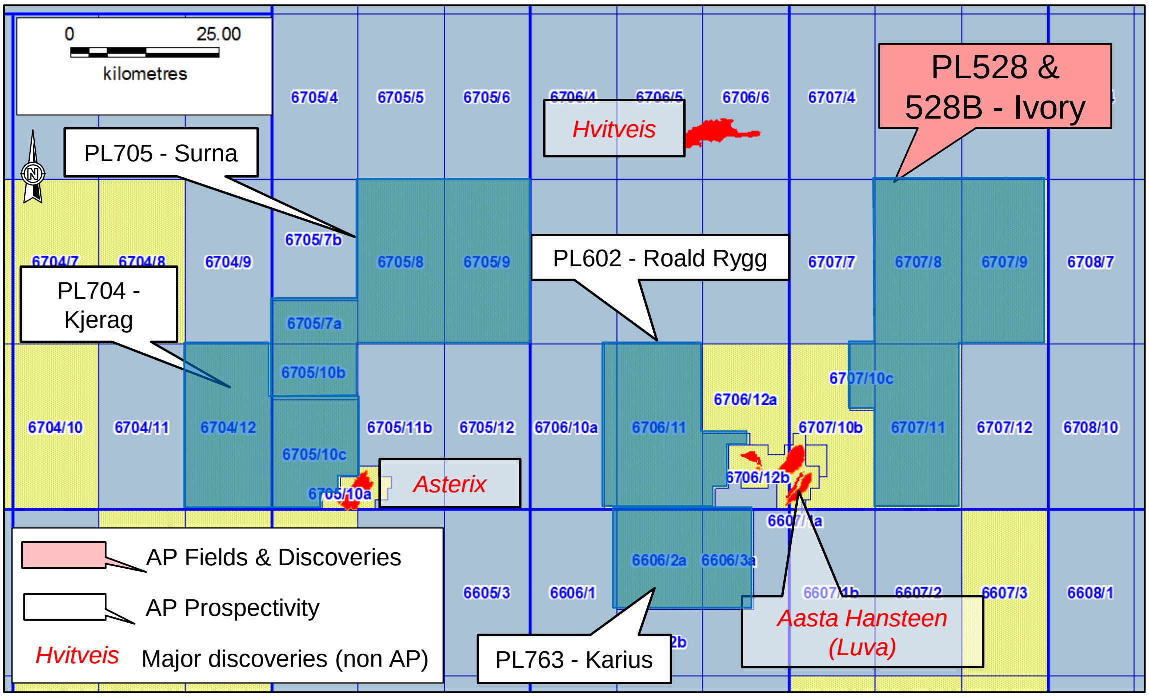
LOCATION OF AP LICENCES IN HAMMERFEST BASIN, BARENTS SEA, NORWAY



Source: GCA after Deloitte

FIGURE 0.9

LOCATION OF AP LICENCES IN VØRING BASIN, NORWEGIAN SEA, NORWAY



Source: GCA after Deloitte

TABLE 0.7

**AP LICENCES IN NORWAY
AS AT 31st DECEMBER, 2014**

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Ivory	PL528 & PL 528B	6707/8, 6707/6, 6707/10 (part), 6707/11	Exploration	Centrica (40)*, Statoil (25), Wintershall (10), Rocksource (10), Repsol (6)	9	None	May, 2016
Roald Rygg	PL602	6706/11, 6706/10 (part), 6706/12 (part)	Exploration	Statoil (30)*, Centrica (20), Petoro, (20), Rocksource (10), Wintershall (10)	10	Drill or drop decision by May, 2015	May, 2017
Langlitinden	PL659	7221/12, 7222/10, 7222/11, 7222/12, 7121/3 (part), 7122/1 (part), 7122/2 (part)	Exploration	Petoro (30), Det Norske (20)*, Lundin (20), Tullow (15), Rocksource (5)	10	None	Feb, 2020
Kjerag	PL704	6704/12 & 6705/10 (part)	Exploration	Eon (40)* Repsol (30)	30	Drill or drop decision by June, 2017	June, 2020
Surna	PL705	6705/7 (part), 6705/8, 6705/9, 6705/10 (part)	Exploration	Repsol (40)*, Eon (30)	30	Drill or drop decision by June, 2015	June, 2018
Karius	PL763	6606/2 (part), 6606/3 (part)	Exploration	Repsol (40)*, Rocksource (30)	30	Drill or drop decision by Feb, 2016	Feb, 2020

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, 2014 are summarised in Tables 0.8 and 0.9.

TABLE 0.8

OIL RESERVES AS AT 31st DECEMBER, 2014

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	4.46	6.63	9.04	8.3	0.37	0.55	0.75
Blackbird	1.17	3.51	7.87	9.4	0.11	0.33	0.74
Chestnut	2.00	4.33	7.53	15.0	0.30	0.65	1.13
Orlando	8.48	15.32	21.52	25.0	2.12	3.83	5.38
Kells	1.88	4.20	5.16	25.0	0.47	1.05	1.29
Total	**17.99**	**33.99**	**51.12**		**3.37**	**6.41**	**9.29**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the field.
2. Totals may not exactly equal the sum of the individual entries due to rounding.

TABLE 0.9

GAS RESERVES AS AT 31st DECEMBER, 2014

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	2.65	4.10	5.54	8.3	0.22	0.34	0.46
Blackbird	0.53	1.70	3.94	9.4	0.05	0.16	0.37
Kells	19.68	27.52	33.12	25.0	4.92	6.88	8.28
Total	**22.86**	**33.32**	**42.60**		**5.19**	**7.38**	**9.11**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the field.
2. 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 0.10), based on GCA's first quarter 2015 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 1Q15 OIL AND GAS PRICE SCENARIOS

Year	Brent Price (US$/Bbl)	UK NBP Gas Price (pence/therm)
2015	61.73	48.38
2016	68.85	50.18
2017	76.57	50.91
2018	84.29	50.92
2019	92.01	51.22
2020	93.85	50.33
Thereafter	+2.0% p.a.	+2.0% p.a.

TABLE 0.10

POST-TAX NPV OF FUTURE REVENUE FROM RESERVES, NET TO AP AS AT 31st DECEMBER, 2014

Field	Reserves Category	Post-Tax NPV (US$ MM)		
		8%	10%	12%
Ettrick	Proved	1.1	1.3	1.5
	Proved plus Probable	2.1	2.6	3.1
	Proved plus Probable plus Possible	10.5	10.2	9.8
Blackbird	Proved	-2.6	-2.5	-2.4
	Proved plus Probable	3.4	3.4	3.4
	Proved plus Probable plus Possible	10.9	10.4	10.0
Chestnut	Proved	0.1	0.1	0.1
	Proved plus Probable	3.3	3.3	3.3
	Proved plus Probable plus Possible	5.9	5.8	5.8
Orlando	Proved	20.8	17.4	14.4
	Proved plus Probable	47.4	41.2	35.6
	Proved plus Probable plus Possible	74.8	65.4	57.1
Kells	Proved	2.2	1.3	0.5
	Proved plus Probable	19.7	17.6	15.7
	Proved plus Probable plus Possible	27.7	25.0	22.5
Total	**Proved**	**21.6**	**17.7**	**14.1**
	Proved plus Probable	**75.9**	**68.1**	**61.1**
	Proved plus Probable plus Possible	**129.8**	**116.8**	**105.3**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing each license block.
2. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

SENSITIVITY ANALYSIS

In view of the recent volatility in oil prices, GCA has estimated the break-even price for the Kells and Orlando developments, defined here as the Brent Crude oil price at which the net present value (NPV) of AP's projected future cash-flow, as at 31st December, 2014, is equal to zero. A constant oil price, no escalation of costs, no reduction in costs due to lower oil prices, and discount rates of 0% and 10% have been assumed. Results are presented in Table 0.11. For producing assets (Blackbird, Ettrick and Chestnut), the price at which revenue from production equals OPEX for 2015 has been estimated, and is found to be approximately US$30-35/Bbl for Blackbird, US$20/Bbl for Ettrick, and US$40-50/Bbl for Chestnut, again assuming no reduction in costs due to lower oil prices.

TABLE 0.11

BREAK-EVEN BRENT CRUDE OIL PRICE (US$/Bbl)
FOR DEVELOPMENT ASSETS
AS AT 31st DECEMBER, 2014

Discount Rate	Kells		Orlando	
	Proved Case	Proved plus Probable Case	Proved Case	Proved plus Probable Case
0%	65	45	57	48
10%	80	49	65	53

CONTINGENT RESOURCES SUMMARY

The oil and gas Contingent Resources attributed to AP's interests, as at 31st December, 2014, are summarised in Tables 0.12 and 0.13 respectively.

TABLE 0.12

OIL CONTINGENT RESOURCES AS AT 31st DECEMBER, 2014

	Area	Discovery	Gross (MMBbl)			WI (%)	Net to AP (MMBbl)		
			1C	2C	3C		1C	2C	3C
Moray Firth Area	Witch Ground Graben	Core Perth	34.8	47.8	78.0	13.35	4.6	6.4	10.4
		NE Perth	6.3	12.3	20.0	13.35	0.8	1.6	2.7
		Dolphin	2.0	6.0	14.0	13.35	0.3	0.8	1.9
		Gamma/ Spaniards	8.1	18.9	33.6	3.24	0.3	0.6	1.1
	Ettrick	Bright	12.3	18.6	27.2	8.27	1.0	1.5	2.2
		Polecat	12.8	20.8	31.4	50.00	6.4	10.4	15.7
		Marten	2.2	6.7	20.8	50.00	1.1	3.4	10.4
	Western Moray Firth	Wester Ross	1.0	2.3	4.0	20.00	0.2	0.5	0.8
		Liberator	3.4	9.6	26.0	20.00	0.7	1.9	5.2
	Total		**82.9**	**143.0**	**255.0**		**15.4**	**27.1**	**50.4**
Central North Sea	Orchid	Orchid	4.0	5.0	8.0	10.00	0.4	0.5	0.8
	Total		**4.0**	**5.0**	**8.0**		**0.4**	**0.5**	**0.8**
Ireland	North Celtic Sea	Helvick	1.5	2.1	2.6	18.33	0.3	0.4	0.5
		Hook Head	25.2	35	47.2	18.33	4.6	6.4	8.7
		Coral/ Dunmore	0.5	0.7	1.0	18.33	0.1	0.1	0.2
	Total		**27.2**	**37.8**	**50.8**		**5.0**	**6.9**	**9.3**
Norway	Hamm-erfest Basin	Langlitinden	7.3	17.7	42.8	10.00	0.7	1.8	4.3
	Total		**7.3**	**17.7**	**42.8**		**0.7**	**1.8**	**4.3**
Total			**121.4**	**203.5**	**356.6**		**21.5**	**36.3**	**64.8**

Notes:

1. Gross Field Contingent Resources are 100% of the volumes estimated to be recoverable from the field, in the event that it is developed.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the field may not be developed in the form envisaged or not at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

TABLE 0.13

GAS CONTINGENT RESOURCES AS AT 31st DECEMBER, 2014

Area	Discovery Name	Gross (Bscf)			WI (%)	Net To AP (Bscf)		
		1C	2C	3C		1C	2C	3C
Southern North Sea	Fulham & Arrol	17.0	42.0	63.0	5	0.9	2.1	3.2
	Pegasus North	30.1	103.7	310.1	10	3.0	10.4	31.0
	Pegasus West	37.5	72.2	138	10	3.8	7.2	13.8
	Total	**84.6**	**217.9**	**511.1**		**7.7**	**19.7**	**48.0**
Norway	Caurus	98.9	123.6	151.9	10	9.9	12.4	15.2
	Ivory	70	131	231	9	6.3	11.8	20.8
	Total	**168.9**	**254.6**	**382.9**		**16.2**	**24.2**	**36.0**
Total		**253.5**	**472.5**	**894.0**		**23.9**	**43.9**	**84.0**

Notes:

1. Gross Field Contingent Resources are 100% of the volumes estimated to be recoverable from the field, in the event that it is developed.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the field may not be developed in the form envisaged or not at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.
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 0.14 and 0.15. 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.

Gaffney, Cline & Associates

TABLE 0.14

OIL PROSPECTIVE RESOURCES (PROSPECTS) AS AT 31st DECEMBER, 2014

Area	Area	Prospect	Gross (MMBbl)			WI (%)	Net to AP (MMBbl)			GCoS (%)
			Low	Best	High		Low	Best	High	
Moray Firth UK	Witch Ground Graben	Perth Northern Terrace	10.0	36.0	90.4	13.35	1.3	4.8	12.1	16
		Perth East	1.8	4.2	6.8	13.35	0.2	0.6	0.9	23
		Perth West	5.0	11.4	20.0	13.35	0.7	1.5	2.7	40
	Ettrick Area	Badger	1.1	2.9	8.4	50.00	0.6	1.5	4.2	27
Central North Sea	Orchid	Orchid West	4.0	8.1	17.2	10.00	0.4	0.8	1.7	40
	Skerryvore	Skerryvore Mey Sst	9.0	16.0	27.0	30.50	2.7	4.9	8.2	26
	Skerryvore	Skerryvore Chalk (including extension)	31.0	66.0	119.0	30.50	9.5	20.1	36.3	30
West of Shetland	Eddystone	Eddystone	71.0	166.0	328.0	43.00	30.5	71.4	141	9
	Davaar	Davaar	75.0	159.0	285.0	30.00	22.5	47.7	85.5	15
Ireland	Porcupine Basin	Dunquin South	58.1	363.4	959.2	5.37	3.1	19.5	51.5	12
Norway	Langlitinden	Snøtinden 1	1.9	3.8	9.4	10.00	0.2	0.4	0.9	35
		Snøtinden 2	2.5	6.3	15.1	10.00	0.3	0.6	1.5	35
		Snøtinden 3	2.5	5	12	10.00	0.3	0.5	1.2	35

Notes:

1. 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.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery. This does not include any assessment of the risk that a discovery, if made, may not be developed.
3. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that no discovery will be made or that any discovery would not be developed.
4. Identification of Prospective Resources associated with a Prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.
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 0.15

GAS PROSPECTIVE RESOURCES (PROSPECTS) AS AT 31st DECEMBER, 2014

	Licence Area	Prospect	Gross (Bscf)			WI (%)	Net To AP (Bscf)			GCoS (%)
			Low	Best	High		Low	Best	High	
Southern North Sea	Pegasus	Pegasus East	11.0	34.2	100.1	10	1.1	3.4	10.0	39
	Andromeda	Andromeda North	24.4	81.7	186.4	10	2.4	8.2	18.6	41
		Andromeda South	28.7	77.6	171.2	10	2.9	7.8	17.1	41
	Greater York	Apollo N	6.5	23.4	77.0	10	0.7	2.3	7.7	36
		Waterloo	10.5	37.2	234.5	10	1.1	3.7	23.5	36
		Westminster	6.0	30.0	149.8	10	0.6	3.0	15.0	24
		Wallace S	6.5	25.8	97.3	10	0.7	2.6	9.7	24
		Wallace N	4.5	28.2	170.8	10	0.5	2.8	17.1	24
	Orchards	Aurora East	148.9	371.7	1055.1	10	14.9	37.2	105.5	25
		Braeburn	230.0	575.0	1840.0	10	23.0	57.5	184.0	18
		Bonnie Brae	15.7	137.5	271.2	10	1.6	13.8	27.1	6
		Eureka	1.5	16.0	36.6	10	0.1	1.6	3.7	6
	Prometheus	Prometheus	19.0	85.7	361.5	20	3.8	17.1	72.3	60
Norway	Surna	Surna	192.7	347.0	616.9	30	57.8	104.1	185.1	28
	Roald Rygg	R.R. Nise	102.4	395.5	861.7	10	10.2	39.6	86.2	30
		R.R. Kvitnos	28.3	130.7	307.2	10	2.8	13.1	30.7	30
		R.R. Lysing	24.7	74.2	148.3	10	2.5	7.4	14.8	28
		Gymir Nise	49.4	95.4	141.3	10	4.9	9.5	14.1	35
	Karius	Karius	238.4	623.3	1189.1	30	71.5	187.0	356.7	25
		Baktus	144.1	571.0	1256.2	30	43.2	171.3	376.9	19

Notes:

1. 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.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery. This does not include any assessment of the risk that a discovery, if made, may not be developed.
3. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that no discovery will be made or that any discovery would not be developed.
4. Identification of Prospective Resources associated with a Prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.
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, the Society of Petroleum Evaluation Engineers and a Chartered Engineer of the Energy Institute.

The ultimate signatory of the report is Dr. John Barker, Technical Director, Reservoir Engineering, who has 30 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
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.

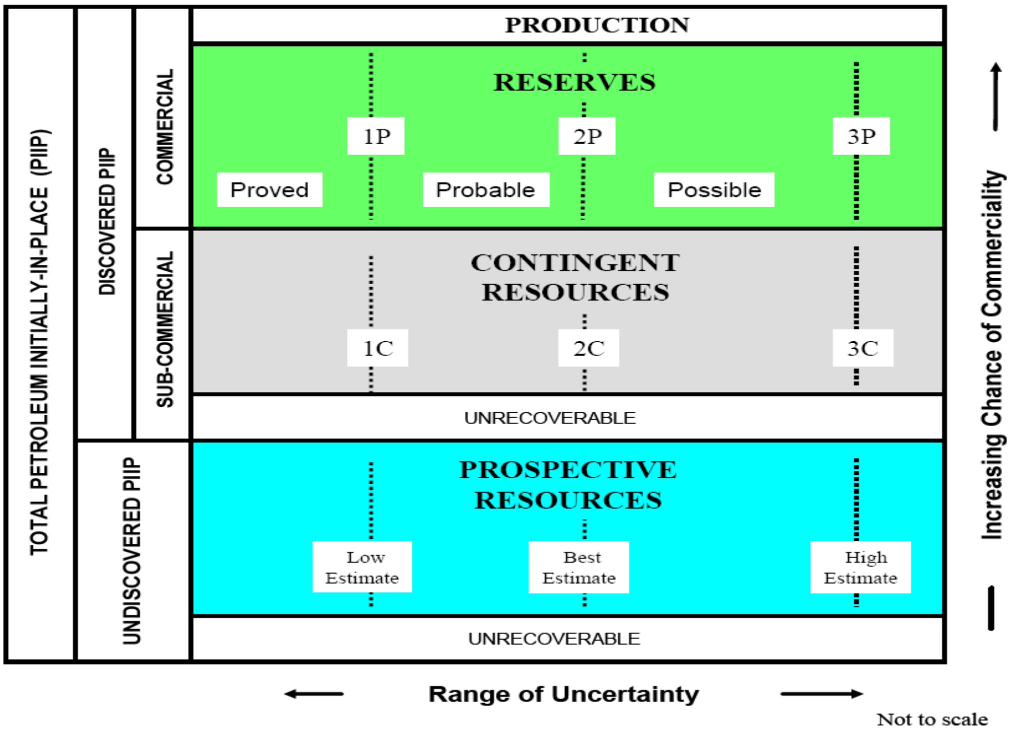
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under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

Play

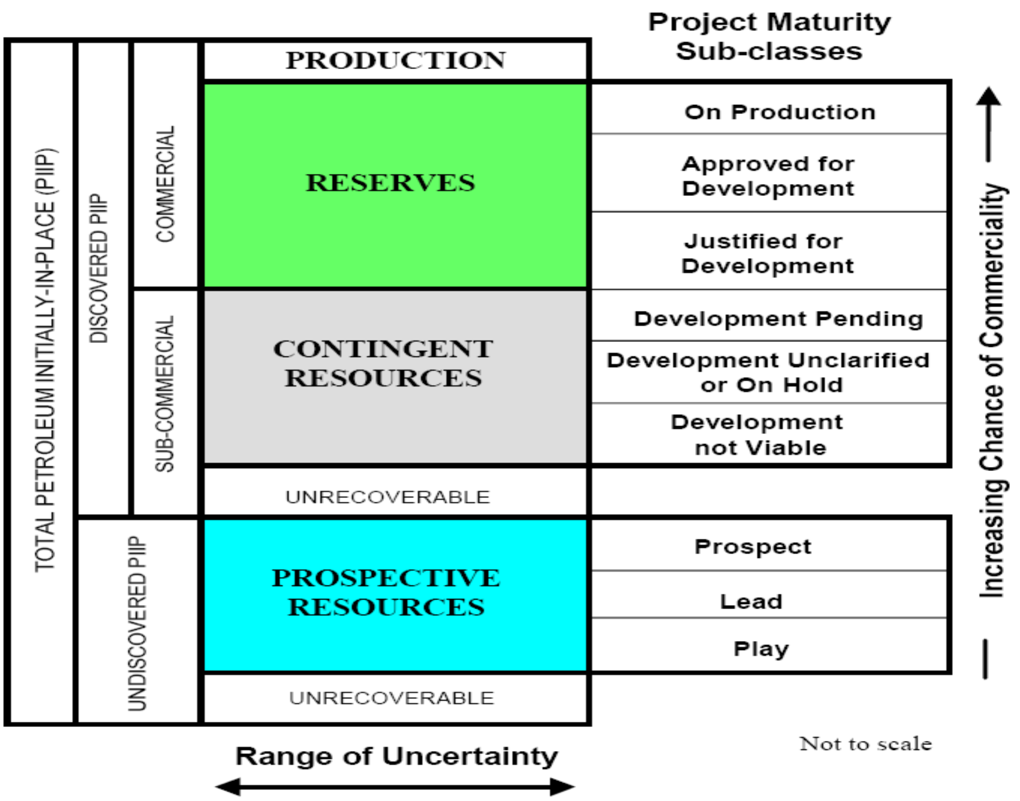
A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

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

GLOSSARY
List of Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment expenditure
ACQ	Annual contract quantity
API	American Petroleum Institute
°API	Degrees API (a measure of oil density)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus offset
B	Billion (10^9)
Bbl	Barrels
/Bbl	Per barrel
BBbl	Billion barrels
bcpd	Barrels of condensate per day
BCU	Base Cretaceous Unconformity
BHP	Bottom hole pressure
blpd	Barrels of liquid per day
Bm^3	Billion cubic metres
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
BOP	Blow out preventer
bopd	Barrels oil per day
bpd	Barrels per day
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
BS&W	Bottom sediment and water
BTU	British thermal units
bwpd	Barrels of water per day
°C	Degrees Celsius
CAPEX	Capital expenditure
CBM	Coal bed methane
cf	Standard cubic feet
cfd	Standard cubic feet per day
CIIP	Condensate initially in place
CGR	Condensate to gas ratio
cm	Centimetres
CMM	Coal mine methane
CO_2	Carbon dioxide
cP	Centipoise (a measure of viscosity)
CSG	Coal seam gas
CT	Corporation tax
DCQ	Daily contract quantity
Dev	Developed
DHI	Direct hydrocarbon indicator
DST	Drill stem test
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
ELT	Economic limit test
EMV	Expected monetary value
EOR	Enhanced oil recovery
ESP	Electrical submersible pump
EUR	Estimated ultimate recovery
€ / EUR	Euro
°F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FPSO	Floating production, storage and offloading vessel
FSO	Floating storage and offloading vessel
ft	Foot/feet
g	Gram
g/cc	Grams per cubic centimetre
G&A	General and administrative costs
GBP	Pounds Sterling
GCoS	Geological chance of success
GDT	Gas down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOC	Gas oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GTL	Gas to liquids
GWC	Gas water contact
HCIIP	Hydrocarbons initially in place
HDT	Hydrocarbons down to
HSE	Health, Safety and Environment
HUT	Hydrocarbons up to
H_2S	Hydrogen sulphide
IOR	Improved oil recovery
IRR	Internal rate of return
J	Joule (Metric measurement of energy; 1 kilojoule = 0.9478 BTU)
KB	Kelly bushing
kJ	Kilojoules (one thousand Joules)
km	Kilometres
km^2	Square kilometres
kPa	Kilopascal (one thousands Pascals)
kW	Kilowatt
kWh	Kilowatt hour
LKG	Lowest known gas
LKH	Lowest known hydrocarbons
LKO	Lowest known oil

LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTI	Lost time injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
MBbl	Thousands of barrels
Mbopd	Thousands of barrels of oil per day
Mcf or Mscf	Thousand standard cubic feet
MCM	Management committee meeting
m^3d	Cubic metres per day
mD	Millidarcies (a measure of rock permeability)
MD	Measured depth
MDT	Modular dynamic tester (a wireline logging tool)
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
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
MMcf or MMscf	Million standard cubic feet
Mode	Value that exists most frequently in a set of values = most likely
Mcfd or Mscfd	Thousand standard cubic feet per day
MMcfd or MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring while drilling
MWh	Megawatt hour
mya	Million years ago
n/a	Not applicable
NBP	National Balancing Point
NGL	Natural gas liquids
N_2	Nitrogen
NOK	Norwegian krone
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
OBM	Oil based mud
OCM	Operating committee meeting
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil water contact
p.a.	Per annum
Pa	Pascal (metric measurement of pressure)

P&A	Plugged and abandoned
PAD	Petroleum Affairs Division
PD	Proved developed
PDP	Proved developed producing
%	Percentage
PI	Productivity index
PJ	Petajoules (10^{15} Joules)
ppm	Parts per million
PRMS	Petroleum Resources Management System
PSC / PSA	Production sharing contract / Production sharing agreement
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	Value with a 10% probability of being exceeded
P50	Value with a 50% probability of being exceeded
P90	Value with a 90% probability of being exceeded
RF	Recovery factor
RFT	Repeat formation tester (a wireline logging tool)
RT	Rotary table
RUB	Russian Rouble
R_w	Resistivity of water
SCAL	Special core analysis
scf	Standard cubic feet
scfd	Standard cubic feet per day
S_o	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRP	Sucker rod pump
ss	Subsea
ST	Side track
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
Undev	Undeveloped
USGS	United States Geological Survey
US$	United States Dollar
VAT	Value added tax
VSP	Vertical seismic profiling
WC	Water cut
WI	Working interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
WUT	Water up to
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional (time lapse)
1H13	First half (6 months) of 2013 (example of date)
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
2Q14	Second quarter (3 months) of 2014 (example of date)