1 January 2010

The Board of Directors
Atlantic Petroleum
Gongin 9
FO110 Tórshavn
Faroe Islands

Dear Sirs

Evaluation of the Petroleum Assets of Atlantic Petroleum & its Subsidiary Companies (Technical)

In response to your request, Fugro Robertson Limited (FRL) have reviewed the petroleum interests of Atlantic Petroleum P/F and its subsidiary companies (AP) offshore the United Kingdom Continental Shelf (UKCS), offshore southern Eire (Celtic Sea) and The Faroe Islands Offshore Area. The evaluation is at 1 January 2010 and is based on technical data and information available and provided by AP up to 31 December 2009. This report documents the review of AP and comprises a Competent Persons Report (CPR) for Danish and Icelandic stock market purposes.

1. Professional Qualifications

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

FRL have reviewed and valued the assets of AP on a number of occasions. The last valuation was dated February 2009 and also took the form of a CPR.

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

2. Introduction and Licence Descriptions

2.1 History

AP was formed in February 1998 as an independent Faroes upstream oil and gas company. Since that time it has been awarded exploration licences in the Faroe Islands and the UK. Additionally the company has completed two UK asset acquisitions and farmed into UK and Eire exploration and appraisal acreage. In January 1999 a co-operation agreement was signed with the 'Faroes Partnership', a consortium applying for acreage in the first Faroes licence round. The application was successful and in August 2000, the consortium was awarded licence 001 in the Judd Basin adjacent to UK waters. The first discovery of oil and gas in the Faroes sector of the North East Atlantic was made with the 6004/16-1Z Marjun well in 2001 that was drilled and funded by the Faroes Partnership.

In July 2003, AP, together with its UK subsidiary, Atlantic Petroleum UK Limited, acquired a number of UKCS oil assets from Premier Oil Plc. These comprised the Chestnut, Ettrick and Perth discoveries and prospects within the licence area, adding to AP's position in the UKCS. In 2005 AP was awarded interests in two new exploration licences (L013 and L014) in the second Faroese licensing round.

In June 2005 AP became the first Faroese company listed on a securities market by being listed on the Icelandic Stock Exchange (ICEX) and, in August of that year, AP farmed into the West Lennox discovery and the Crosby exploration prospect, both located in the Irish Sea (Licence P.099). In December the L001 group earned an interest in L006 in the Faroes with the drilling of the Brugdan 6104/21-1 well. In October 2006 AP were listed on the Nasdaq OMX Copenhagen Stock Exchange.

During 2007 AP farmed into a number of UK and Irish licences commencing in February 2007 with Licences SEL 2/07 and SEL 3/07 in the North Celtic Sea Basin offshore Eire. This acreage included the Hook Head oil discovery, as well as including the Ardmore, Dunmore and Helvick discoveries. There are also a number of prospects that have been identified in the vicinity of these discoveries in the Celtic Sea. In May 2007 AP farmed into block 30/23b located in the UK North Sea that held the Balgownie prospect and Cullen lead. A well was drilled in June 2007 on the Balgownie prospect and was later plugged and abandoned. In June 2007 AP completed a farm-in to the Anglesey prospect located in the UK continental shelf, blocks 14/9a and 14/14b. AP has also executed a farm-out contract with Fox Energy on these licences that reduced their equity in return for payment of seismic data and optionally well costs. Additionally in late 2007 AP completed the acquisition from Shell of an interest in the UKCS Marten oil discovery, located in block 20/3c. This sour oil discovery lies near to the Ettrick Field and plans for development involve a tie-back to the Ettrick FPSO or Buzzard Platform of Marten and a number of similar sour discoveries located nearby.

The Chestnut Field came on stream on 20 September 2008. The 20/2a-8 Blackbird Prospect was drilled and declared an oil discovery in mid August 2008. The well tested at an average restricted rate of 3,800 BOPD from a net pay of 110ft. The discovery is 6km from the Ettrick Field and after appraisal drilling the expectation is for a tie-in to the Ettrick production facilities.

In early November 2008 AP announced a successful appraisal well 22/2a-16Y on the South Chestnut prospective extension to the main Chestnut Field. This well tested at a maximum flow rate of 8,200 BOPD.

In August 2009 the Ettrick Field came on stream at an average rate for the year of 13,800 BOPD.

Little work has been carried out on the Celtic Sea assets in 2009.

2.2 AP Activity in 2009

The Chestnut Field has continued to produce at an average rate of 9,300 BOPD through 2009. The South Chestnut 22/2a-16Y appraisal/production well was tied into the Chestnut Field development in March 2009.

The Ettrick Field came on stream on 15 August 2009 and has since produced at an average rate of 13,800 BOPD.

The Crosby exploration well was drilled in 2009 but was a dry hole; this will result in the relinquishment of the 110/14c and 14d blocks in the East Irish Sea in 2010.

2.3 AP Current Licence Interests

The current licence interests held by AP in the UK, Eire and the Faroes are summarised below.

Country	Licence	Blocks	AP Interest (%)
Faroe Islands	L013	6103/7b,8b,12,13 & 17	40%
Faroe Islands	L014	6104/9b,10b & 14	40%
Faroe Islands	L006	6105/25 & 30, 6005/5a, 6104/16a,17a,21 & 26, 6004/1a	1%
Faroe Islands	L016	6201/1,2,6, 6202/4,5,6,7,8,9,10,11,12,13,14,15,16,17,18,21,22, 6203/13,14,15,16,17,18,19, 20,21,22,23,24,25	10%
UK	P218 & P588	15/21a, b, c & f	3.75%
UK	P273 & P317	20/2a & 3a	8.27% (Note 2)
UK	P354	22/2a	15%
UK	P099	110/14c & d	7.5% on Crosby area, 12.5% on W Lennox area (Note 1)
UK	P1478	110/9c & 14e	7.5%
UK	P1047	20/3c	17.5%
UK	P1580	20/3f	8.27%
Ireland	SEL 2/07	49/8,9,13,14,18,19, & 50/6,7,11 & 12 (part blocks)	18.333%
Ireland	SEL 3/07	48/29, & 30, 49/26 (part blocks)	18.333%

1. On UK P099 the previous co-venturer retains the option to re-acquire 5% of the AP interest.
2. On UK P317, block outside of the Ettrick Field area Premier Oil has a back-in option for a 5.515% licence interest from AP's equity share in exchange for payment of all AP past exploration costs in the event of a discovery on the block. This right was not exercised for the Blackbird discovery.

3. Data and Evaluation Basis

3.1 History

FRL have evaluated the assets of AP on a number of occasions from 2003 onwards. These valuations have been used for stock rights issues and flotations on the Icelandic and Danish stock exchanges. The last evaluation was effective at 1 January 2009 and was presented as a CPR and also a Reserves Report within the AP Annual Report and Accounts.

3.2 Data

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

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

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

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

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

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

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

4. Summary of Resources and Reserves

The UKCS Chestnut Field came on production in September 2008. The Chestnut South discovery was announced in November 2008 and tied back to the Chestnut Field. The Ettrick development came on production in August 2009. FRL consider these assets to contain petroleum reserves and estimate the remaining economically recoverable volumes attributable to AP by asset and in aggregate to be as follows:

Petroleum Reserves Remaining at 1 January 2010 (MMBOE)			
Field	**P90**	**P50**	**P10**
Chestnut	0.6	1.1	1.8
Ettrick	1.0	2.3	3.6
Aggregated Total	**1.6**	**3.4**	**5.4**

Note: In all tables the numbers have been rounded up

The UKCS Perth, Blackbird, Marten, Bright, Dolphin, Gamma Central and West Lennox discoveries, wells in the Perth area, and the Celtic Sea Hook Head, Helvick and Ardmore discoveries have all established the existence of petroleum. However, commerciality of the assets may not have been established, development plans have not been sanctioned, and consequently FRL consider these assets to contain contingent resources.

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

Contingent Resources at 1 January 2010 (MMBOE)			
Discovery	**P90**	**P50**	**P10**
Ardmore	0.2	0.6	1.1
Blackbird	0.3	1.0	2.5
Bright	0.2	0.5	1.7
Dolphin	---	0.3	---
Gamma Central	---	0.4	---
Helvick	---	0.3	---
Hook Head	---	---	---
Marten	0.4	1.1	1.8
North East Perth	---	0.1	---
Perth	0.7	1.0	1.5
West Lennox	---	---	---
Aggregated Total	**---**	**5.3**	**---**

Note: In all tables the numbers have been rounded up

Of the five exploration and appraisal prospects that FRL have evaluated, two prospects are deemed to be economically viable to drill. FRL estimate the prospective resources of the exploration and appraisal prospects attributable to AP by asset and in aggregate to be as presented in the following table. Where a figure is not stated this is due to insufficient data to fully evaluate the asset.

Prospective Resources at 1 January 2010 (MMBOE)			
Prospect	**P50 Un-Risked**	**P50 Risked**	**Economically Viable to Drill?**
Blackrock Prospect (Part Blocks (48/30, 49/26)	0.6	0.1	No
Brugdan Deep Prospect (6104/16a, 17a & 21, 6105/25)	---	---	---
East Perth Prospect (15/21a)	0.2	0.1	Yes
North Perth Prospect (15/21a)	0.4	0.2	Yes
Rushane Lead (Part Blocks 48/29, 48/30)	---	---	---
Aggregated Total of Viable Prospects	**1.2**	**0.4**	

Note: In all tables the numbers have been rounded up

5. UK Production

AP has an interest in two producing fields; namely Chestnut, which now comprises the main Chestnut Field plus the recent extension discovery Chestnut South and the Ettrick Field, which also includes Jarvis.

5.1 Chestnut Field (22/2a)

The Chestnut Field was discovered in 1986 in 400ft of water by the 22/2-5 well, which tested 6,500 BOPD from a 67ft interval of Eocene sands at 6,960ft. Test rates were not stabilised, water production varied from 30% to 60%, and significant amounts of sand were produced. A second well and sidetrack, 22/2a-7 and 7Z, tested 4300 BOPD from an 80ft interval, with no water cut.

The 22/2a-11Z well was drilled horizontally into the northern part of the field in 2001. It penetrated a 550ft reservoir section, and produced 1.05 MMBO over a four month period under test conditions. Water cut increased to a steady 20% during the test without demonstrating any dependency between water cut and oil rate.

The reservoir is the Nauchlan Sand of mid to late Eocene age. It is the chronostratigraphic equivalent of the Alba Sand in the large Chevron operated Alba Field to the north. The well data shows the sand to vary from 7ft to 121ft (average 65ft) thickness across the field. The reservoir is interpreted as a combination of injectite and turbidite sands, displaying very good porosities, permeabilities and net to gross characteristics. Porosities average 30% and permeabilities in the 1-5 Darcy range. STOIIP determined by the various operators of the field has varied from 32 to 69 MMBO (P50). FRL's estimates of STOIIP are similar to the operator's current estimates at 37.7 MMBO (P90), 48.4 MMBO (P50) and 58.1 MMBO.

Development of the Chestnut Field was sanctioned in 2006 based on one production and one water injection well. A Sevan SSP300 floating production unit ('Hummingbird') has been constructed and was on location in the field from December 2007. First oil was delayed compared to the sanction target but was achieved on 20 September 2008. Produced fluid is now being processed and oil stored on the floating production unit with oil export via shuttle tankers. Current production is from the 22/2a-11X well and the 22/2a-16Y well to the south (drilled in 2008 and brought on stream on 17 March 2009), with pressure support provided via well 22/2a-12, drilled in 2007.

Chestnut has achieved an average oil production rate in 2009 of 9300 BOPD and a cumulative production of 4.5 MMBO of oil to 31 December 2009.

Production performance during 2009 has been stable. Although the overall production has been below expectation during 2009, the production rate decline and water-cut rise have both been moderate. The bulk of the production has been from the 22/2a-11X well in the main part of the field where the water injection support has been very effective.

Our estimates of reserves for the Chestnut Field include the additional volumes in the southern extension confirmed by the 22/2-16 well.

5.2 Chestnut Reserves

Our estimates of ultimate and remaining oil reserves in the Chestnut Field, after the economic cut-off, and excluding the 1.05 MMBO of test production in 2001, are:

Chestnut Field (22/2a)			
	P90	**P50**	**P10**
Field Ultimate Gross Reserves:			
Oil (MMBO)	8.5	11.8	16.5
Field Gross Production to 31-12-2009:			
Oil (MMBO)	4.5	4.5	4.5
Field Gross Reserves at 31-12-2009:			
Oil (MMBO)	4.0	7.3	12.0
Net AP Reserves (15% WI):			
Oil (MMBO)	0.6	1.1	1.8
Total (MMBOE)	**0.6**	**1.1**	**1.8**

Note: In all tables the numbers have been rounded up

5.3 Ettrick Development (20/2a, 20/3a)

The Ettrick Field was discovered in 1981 by the 20/2-1 well, which penetrated oil-bearing sandstones in the Upper Jurassic Ettrick sands reservoir and was tested at 4538 BOPD. The field, which lies in 378ft water depth, was appraised by seven wells from 1982 to 1985, four of which flowed hydrocarbons to surface on test.

The trap is a faulted anticline positioned over a deeper major fault block at Zechstein level. The Ettrick sands reservoir, some 560ft gross thickness, comprises deep-water turbidites encased by shales within the Kimmeridge Clay Formation. The top reservoir is at 10,500ft TVDSS. The sandstone reservoir is vertically compartmentalised by extensive shale layers. The field oil-water contact for the core area is interpreted at 10,605ft. Major faults further subdivide the field laterally. Reservoir quality is moderate, with average porosities of 19% and permeabilities of 425 mD. Net to gross is poor however (23%) giving a net pay thickness of 70ft in the crest of the structure thinning to 20ft in the eastern flank. Initial drilling also proved the existence of a productive Zechstein reservoir beneath the Ettrick reservoirs in the core central area of the field.

Field development was approved in mid 2006 with the development plan comprising three new production wells and one injector well. The FPSO (Aoka Mizu) was built in Singapore using a bare hull and now operates at Ettrick under a lease agreement. Development drilling commenced in 2007 and continued into 2009. To date, six development wells have penetrated the reservoir of which four have been completed and are operational as producers and one as a water injector.

Based on logging data, the results of the E1 production well and E4 water injection well drilled in the main core area of the field, were close to expectation. The E3 well however, drilled close to earlier well 20/3-3, was not successful. Contrary to expectations, sandstone development was poor, and the net to gross decreased to 12%, average porosities decreased to 16% and there was an increase in cementation. The character of the sandstones are typical of distal turbidites bringing into doubt the existence of thicker Ettrick sands to the east of this well; corroborated by the results of a 2008 commissioned sedimentological study. Based on the well results, the operator has concluded that the core area of the field is much smaller than anticipated leading to a significant reduction in STOIIP. A sidetrack of the E3 well is scheduled to be drilled in early 2010 as an additional production well.

In response to the results of wells E1 and E3 an additional development well (E5) was drilled in 2008 in the crest of the structure close to discovery well 20/2-1. The results of this well were as expected with 70ft of net sand, a net to gross ratio of 31%, average porosities of 22% and a relatively stable test flow rate from just the upper E Sand of 4500 BOPD.

The E2 well was successfully drilled into the southern area of the field with the well results being close to the geological model of the sanction case. The deeper F sands were oil bearing but thinner than predicted. Pressure data from the E2 well is consistent with a stacked sand system with separate oil-water contacts in each sand and suggests that the southern area of the field is located within a separate reservoir compartment to the core central area. This has since been confirmed by early production performance pressure response.

The Jarvis accumulation lies in Zechstein dolomites, which underlie the main Ettrick Field reservoir. Three wells have tested this accumulation: 20/2-1, 2 and 3. The tests on wells 20/2-1 and -3 only produced at rates below 60 BOPD. However, well 20/2-2, drilled in 1982, tested 9198 BOPD of 36º API oil from the Halibut Dolomite. The overlying Turbot Dolomite tested 4414 BOPD of 38º API oil.

The 20/2a-E6 well was completed in 2009 as a Zechstein Jarvis and Ettrick sands producer, in the north of the central area of the field, close to the 20/2-2 appraisal well location. This well has subsequently been tied in to the Ettrick facilities and Zechstein production commenced in December 2009.

The North Ettrick (Ettrick Sand) accumulation is separated from the main Ettrick Field by an east-west fault. This accumulation was proved by the 20/2-2 well that tested 2400 BOPD from this formation as well as producing from the Zechstein. Production for the North Ettrick (Ettrick Sand) area will likely require a dedicated producer. A well is scheduled to be drilled in 2010.

With available seismic, an incomplete operator static model and the highly variable reservoir thicknesses from well to well, an accurate deterministic STOIIP cannot be calculated with confidence. The Ettrick sands are stratigraphically complex, not readily distinguished on the generally poor quality seismic data, and have proved difficult to model geologically from the well data.

FRL's estimate of STOIIP for the whole field, in the light of the core area revisions, necessitated by some poor development drilling results, is 49 – 87 – 135 MMBO compared to the operator's estimate of 65 – 100 – 160 MMBO.
First production from Ettrick came on 15 August 2009, which was later than FRL had assumed in their previously evaluation. FRL are of the opinion that additional drilling will be required to fully develop the field reserve, either with new wells or sidetracks of existing wells. The additional cost for these wells has been included in the estimated budget.

Since first oil production on 15 August 2009, Ettrick has achieved an average oil production rate in 2009 of 13,800 BOPD and cumulative production of 1.92 MMBO of oil to 31 December 2009.

Production performance has been good although FRL have concerns that the bulk (87%) of the production has come from the P5 (E5) well. However, it is noted that simultaneous full production from all of the wells has not yet been possible due to operational and processing constraints. Both P5 (E5) and P1 (E1) have demonstrated a clear response to water injection from well WI5 (E4), which is performing acceptably with injection rates currently being maintained at about 30,000 BWPD. A total volume of ~1 MMBO of water has now been injected.

The P2 (E2Z), which is south of the fault, is demonstrating from its bottom hole pressure response that it is isolated from the main area of the field, as predicted. The Jarvis (E6) well commenced oil production from the Zechstein Formation in December 2009 at rates of 3000 BOPD to 4000 BOPD. The bottom hole pressure declined, as had been expected, but it is understood that the well was shut in after just two weeks due to processing constraints rather than reservoir performance. E6 is reportedly due to be returned to production in early 2010. The intention is to cycle well E6 production between the Zechstein Formation and shallower Ettrick Formation.

Although elements for the FPSO top sides have worked well, e.g. water injection, FRL have concerns over the up time of the topsides facilities in this early production period of Ettrick.

5.4 Ettrick Reserves (Including Jarvis)

FRL's estimates of ultimate and remaining oil reserves in the Ettrick Field, after the economic cut-off, are:

Ettrick Field (22/2a)			
	P90	**P50**	**P10**
Field Ultimate Gross Reserves:			
Oil (MMBO)	13.6	27.5	42.2
Gas (BCF)	5.3	13.2	21.6
Field Gross Production to 31-12-2009:			
Oil (MMBO)	1.9	1.9	1.9
Gas (BCF)	1.0	1.0	1.0
Field Gross Reserves at 31-12-2009:			
Oil (MMBO)	11.7	25.6	40.3
Gas (BCF)	4.3	12.2	20.6
Net AP Reserves (8.27% WI):			
Oil (MMBO)	1.0	2.1	3.3
Gas (BCF)	0.4	1.0	1.7
Total (MMBOE)	**1.0**	**2.3**	**3.6**

Note: In all tables the numbers have been rounded up

The reserves are being truncated by economic cut-off due to the combination of the declining production rate and the relatively high operating costs that include the lease of the FPSO. There is scope for increasing economic reserves in the event that a Blackbird development over Ettrick is firmed up, which could lead to a saving in unit costs for Ettrick. This could add up to 10% more to the net AP reserves shown above.

6. UK Developments and Discoveries

Other than the Chestnut producing field, AP has interests in seven other UKCS petroleum discoveries including: Blackbird, Marten, Bright, Dolphin, Gamma Central, Perth, North East Perth and West Lennox. The Jarvis and North Ettrick discoveries are treated as part of the Ettrick Field.

6.1 Blackbird Discovery (20/2a, 20/3a, 20/3f)

AP acquired an 8.269% interest in the Ettrick Pre-Unitisation area (20/2a & 20/3a) and an 11.025% interest in Block 20/2a from Premier in 2003. In December 2005, the 20/2a and 20/3a groups agreed to equalise their interest. AP now holds an 8.27% interest in these two blocks, including the Ettrick Field. FRL have been advised by AP that a part of the equalisation process involved taking on an Over Riding Royalty (ORR) agreement on the non Ettrick Pre-Unitisation Area of Block 20/3a. AP advises that the ORR rate is 3% of production and this has been included in the assessment of the Blackbird Prospect although it has negligible impact on the economic metrics in this report. AP also has an 8.27% interest in the Block 20/3f, awarded February 2009.

The Blackbird structure lies in the southern part of blocks 20/2a and 20/3a and potentially extends into 20/3f. The structure is a structural trap on the downthrown side of a major east-west trending fault, which forms the southern closure. It is separated from the Ettrick Field structure by a syncline at Upper Jurassic levels. The reservoir is the Upper Jurassic Ettrick sandstone at around 11,100ft, top sealed by Upper Jurassic shales and sourced from the enveloping Jurassic shales to the north.

Well 20/2a-8 was drilled successfully in 2008. It encountered two good Ettrick Sand intervals, each with 39ft net pay, near the top of the reservoir section that are correlated with the main E1 and E2 sands of the Ettrick Field. The well successfully flowed to surface at a maximum rate of 3850 BOPD of 37° API oil. Review of the pressure transient analysis of the 20/2a-8 drill stem tests is consistent with a limited connectivity reservoir, similar to Ettrick.

Porosities averaged 20%, net to gross 23% (E1 and E2 sands). Formation pressure data indicates an oil water contact at 11,210ft SS, 600ft deeper than the Ettrick Field. A further oil leg is also present in a deeper F Sand unit, but with only 18ft of pay above a separate oil water contact.

As an Ettrick Sand discovery, Blackbird is expected to have similar geological complexities as the Ettrick Field, situated 6km to the north. The latest operator figures for in-place volumes are a range of 31 - 45 - 58 MMBO. This is too narrow a range for a single well discovery of this size and potential complexity. Using the 20/2a-8 discovery well data and the operator supplied maps FRL have calculated a similar mid case in-place volume but with a more representative range of 16 - 54 - 120 MMBO.

The logical development for Blackbird is as a subsea tieback to Ettrick. The common partnership and fluid type similarity, as well as the relatively short tieback distance, render any other option improbable. With the potential reserve and production from Ettrick being less than the sanction design capacity there should be ullage available on the Ettrick FPSO.

There is an appraisal well budgeted to be drilled in 2010 with a potential start to drilling this well as early as March. FRL have assumed that this well will be successful followed by a subsea tieback to Ettrick. FRL believe that development of the mid case reserve is likely to require two producers and two water injectors. First oil has been projected as October 2011, with an initial off take rate of 9000 BOPD.

As Premier Oil did not exercise its right to back-in to Block 20/2a for a 5.515% interest, FRL estimate the oil and gas resources attributable to AP at an 8.27% interest to be as follows:

Blackbird Discovery (20/2a, 20/3a, 20/3f)			
	P90	**P50**	**P10**
Field Gross:			
Oil Reserves (MMBO)	3.0	11.0	27.0
Gas Reserves (BCF)	0.9	5.7	15.9
Net AP Reserves (8.27% WI):			
Oil (MMBO)	0.3	0.9	2.2
Gas (BCF)	0.1	0.5	1.3
Total (MMBOE)	**0.3**	**1.0**	**2.5**

Note: In all tables the numbers have been rounded up

6.2 Marten Discovery (20/3c)

The Marten discovery well 20/3-4, drilled in 1984, found a 200ft oil column in Buzzard equivalent sands at a depth of 11,000ft TVDSS. The well was not tested but oil samples were recovered. The trapping mechanism is part stratigraphic and part structural. Pressure data suggests that the reservoir comprises a series of stacked sands with separate oil-water contacts.

The development of Marten is difficult as the crude is sour and any FDP needs to be approved prior to the licence expiry on 24 July 2010. This will be a significant challenge as Marten is sub-economic as a standalone development and any sour development in the area will be influenced by the results of the Ferret/Polecat appraisal well, due to spud mid 2010. The only alternative export route is a 25km tie back to Buzzard once the fourth platform is installed in the second half of 2010 or early 2011.

Our estimates of oil resources in the Marten discovery are:

Marten Discovery (20/3c) – Contingent Resources			
	P90	**P50**	**P10**
Field Gross:			
Oil (MMBO)	2.5	6.0	10.0
Net AP Reserves (17.5% WI):			
Oil (MMBO)	0.4	1.1	1.8
Total (MMBOE)	**0.4**	**1.1**	**1.8**

Note: In all tables the numbers have been rounded up

6.3 Bright Discovery (20/3a)

Well 20/3-2a, drilled as a deviated well in 1982, found the target Upper Jurassic Ettrick sands to be wet, but the Buzzard sands contained a thin oil column that tested 2587 BOPD before being aborted after only 2.5 hours due to a high H_2S content. An appraisal well, 20/3-6, was drilled down-dip 2.5km to the southeast in 1997, but found only sand stringers and shows.

Bright is interpreted to be a stratigraphic trap, formed by the pinch-out of the Buzzard sands to the west, north and possibly south, with dip closure to the east. Bright could add incremental reserves to Ettrick satellite developments in the area.

Our estimates of oil resources in the Bright discovery are:

Bright Discovery (20/3a) – Contingent Resources			
	P90	**P50**	**P10**
Field Gross:			
Oil (MMBO)	2.0	6.0	20.0
Net AP Resources (8.27% WI):			
Oil (MMBO)	0.2	0.5	1.7
Total (MMBOE)	**0.2**	**0.5**	**1.7**

Note: In all tables the numbers have been rounded up

6.4 Perth Discovery (15/21c)

The Perth Field, lying in 475ft water depth, was discovered in 1992 by the well 15/21b-47 that encountered 509ft of oil bearing Claymore Sand. The well tested at 5880 BOPD of 30º API crude with 2.7 MMCFGD, which contained 36% CO_2 and 5,700 ppm H_2S.

In 1993, the eastern appraisal well 15/21b-49 encountered 858ft of gross reservoir that tested 1280 BOPD. The field was further appraised by well 15/21-56 in 1997 for a 10 day EWT, which produced initially at 4400 BOPD, reducing to 3700 BOPD of 32º API oil with a GOR of 965 SCF/bbl.

Perth is a fault and dip closed structure at Upper Jurassic Claymore sandstone level. The crest of the structure is at about 12,000ft TVDSS with the oil-water contact at 12,993ft TVDSS. Oil in-place volume for the Perth discovery has been assessed in a number of studies during the past 10 years and all are broadly consistent. A STOIIP range of 130 – 200 – 300 MMSTB can be considered as representative. However, due to the reservoir structure and formation properties the oil recovery factor is likely to be low.

Although the Perth Field development was taken to at a very advanced stage by the end of 2001 based upon an Alliance risk-sharing format, that approach was halted. Since then a range of tie-back options have been reviewed but no host platform has yet been agreed. The sour nature of the Perth fluids is understood to be the principal concern for some of the potential host platforms.

There is a requirement to treat and dispose of the high level of H_2S contained within the Perth reservoir fluid. There is about 8,500 ppm of H_2S and 40% CO_2 in the gas phase after separation. Possible gas disposal options include use as platform fuel, flaring or gas re-injection.

The Perth Field was classified as 'Fallow B' in October 2007 by the UK Government and posted on the DECC LIFT fallow website in January 2008. In October 2009 DECC reclassified the field as Fallow BR (B rescued) and granted an extension to the end of September 2010 in the first instance, on the basis of lack of ullage. The status will be reconsidered if ullage becomes available at the end of the extension period.

At present a firm development proposal has not been tabled by the operator and partners to DECC, but the operator is looking at several development options involving FPSOs as well as a tie-back to a host platform.

For this evaluation a base development of three subsea production wells tied back to a nearby host has been assumed. Should production performance justify it, water injection could be incorporated as a second phase of development.

Our estimates of oil and gas resources in the Perth discovery are:

Perth Discovery (15/21c) – Contingent Resources			
	P90	**P50**	**P10**
Field Gross:			
Oil & NGL (MMBO)	17.1	22.8	34.2
Gas (BCF)	15.6	20.9	31.3
Net AP Resources (3.75% WI):			
Oil & NGL (MMBO)	0.6	0.9	1.3
Gas (BCF)	0.6	0.8	1.2
Total (MMBOE)	**0.7**	**1.0**	**1.5**

Note: In all tables the numbers have been rounded up

6.5 North East Perth Discovery (15/21a)

Well 15/21a-7, drilled in 1983, encountered oil bearing Claymore Sand. With 140ft of pay, it tested 911 BOPD of sour crude (1400 ppm of H_2S). The accumulation is mapped as a combination stratigraphic and structural trap on trend with North Perth, but separated from North Perth to the west by faulting and a saddle.

The North East Perth oil resource is estimated at 3 MMSTB at the P50 level, but with the low well test rate achieved from the 15/21a-7 well, development of this discovery is not likely to be viable without further successful appraisal.

6.6 Dolphin Discovery (15/21a)

The Dolphin oil discovery was made by well 15/21a-46, drilled in 1992, which encountered oil in Claymore sands at a depth of 11,100ft TVDSS. The discovery had 93ft of good quality sand in a 241ft section, with oil to the base of the section. The well flowed 3245 BOPD of 38º API crude on test.

Well 15/21a-55 was then drilled updip to the southwest in 1995, but here the Claymore Sand had very poor reservoir properties and only oil shows were present. The Scott Field well 15/21a-E1, also in 1995, was drilled downdip to the east, but failed to encounter sands of Claymore age.
The Dolphin oil resource is estimated at 8 MMSTB at the P50 level but the volume retains a high level of uncertainty on the presence and quality of oil bearing reservoir, as shown by the strikingly different well results.

6.7 Gamma Central Discovery (15/21a)

Well 15/21a-38, drilled in late 1988, was aimed at a Claymore Sand target that proved unsuccessful. However, the well was sidetracked as 15/21a-38Z into a mound-like feature at Burns Sand level, 950ft above the Claymore Sand. The well encountered a 20ft sand that tested 2600 BOPD of 25º API crude with no H_2S. The apex of the mound, with a predicted 250ft of sand, is now mapped on the seismic along strike to the southeast.

The trap is a stratigraphic one, formed by the updip pinchout of the sand mound to the southwest. Our resource estimate of 10 MMSTB at the P50 level remains unchanged but, with the high level of uncertainty associated with this discovery, development is unlikely to be viable without further successful appraisal.

6.8 West Lennox Discovery (110/14c)

Well 110/14-1 was drilled on the West Lennox structure in 1990 and encountered a 25ft oil column in the Sherwood Sandstone at 3379ft TVDSS, with similar properties and oil-water contact depth to the nearby Lennox Field. The well was not flow tested. The seismic depth interpretation indicated an updip four-way dip closure immediately to the east of the well, with a potential 54ft hydrocarbon column.

AP acquired a 25% interest as a member of the Challenger operated group that farmed into Burlington Resources' equity in August 2005.

Appraisal well 110/14c-6 was drilled in September 2005 to test this mapped closure. In the light of the disappointing results from the Crosby exploration well, Block 110/14c and West Lennox are to be relinquished in March 2010.

7. Eire Discoveries

7.1 Hook Head Discovery (Part Block 50/11)

The Hook Head discovery well 50/11-1 was drilled in the North Celtic Sea Basin in 1971. The well logs indicated 104ft of possible pay, with 68ft of net pay between 1180ft and 4748ft TVDSS (Wealden Units 5, 4, 3 and 2). The well was not tested and the fluid type was not confirmed. 30º API oil was recovered from cuttings, with a reported 6% wax content and a GOR of 600 SCF/STB. An appraisal well (50/11-2), drilled in 1975 off structure in the Central compartment, was water wet.

Well 50/11-3 was drilled in 2007 and encountered good oil and gas shows in Wealden Unit 5 and above. However, due both to the condition of the hole and operational constraints, no wireline logs were run and only LWD logs are available. No formation pressure data or information on the hydrocarbon water contacts was obtained. Testing of the well was attempted but was not successful due to technical difficulties. A small volume of oil was recovered from the Wealden Unit 5 (perforated 70' section from 2753' – 3206').

Well 50/11-4 was drilled in 2008 on the northern flank of the structure. Thin gas bearing sands, separated by thick shales were identified on the LWD logs in the upper part of the Wealden section (Wealden Units 6 and 8) but conventional electric logs were not run, nor was the well tested or any pressure data acquired.

The field is interpreted as a domal structure of around 6400 acres. It is mapped as comprising six main compartments. Average log porosities of the net pay sands are good at 24%; however, individual sands are typically less than 20ft thick and encased in thick sections of shales and other non-pay sandstones.

None of the wells has provided sufficient basic data (logs, pressure, core, SCAL, PVT, etc) to establish a coherent geological model for the field. Multiple oil water contacts are likely. However, due to the lack of data acquisition from the past wells, there is no confidence in any assessment of hydrocarbon column heights, pressure or potential aquifer support.

Any development of the reservoir with its multiple sands would require a significant number of production wells. Aquifer pressure support is likely to be limited and therefore oil recovery factors would be low. A mixed oil and gas reservoir is indicated, which further complicates any development potential.

FRL have not included Resource estimates in this report due to the lack of firm data that would allow volumes to be calculated with an appropriate degree of confidence, and due to the absence of any economically viable development concept for this combination of volumes, fluids and location.

7.2 Ardmore Discovery (Part Blocks 49/13, 49/14, 49/18, 49/19)

Well 49/14-1, drilled in 1974-1975, tested a stacked series of Lower Cretaceous Wealden sandstones at a combined rate of 8.6 MMCFGD. The highest test rate of 4 MMCFGD was from the deepest tested interval at 5520ft. The operator interprets the uppermost interval, named DST 7/8 after the drill stem tests within the interval, to be a transgressive marine sandstone. DST 8 produced at 1.6 MMCFGD, but should be a more laterally extensive, connected sand body, than the older and deeper fluvial Lower Cretaceous sands.

Well 49/14-2, drilled in 1975 as an appraisal well, encountered oil and gas shows, but the single DST run failed to test hydrocarbons. The operator's mapping interprets well 49/14-2 to be outside the structural closure.

In auditing the available data and the operator's calculations FRL estimate a mid-case GIIP of 23 BCF, compared to the operator's estimates of 46.8 BCF. FRL have assumed the Ardmore development is based upon a sub-sea tieback to the Kinsale Head gas field (48km northeast of Ardmore) routed through the Old Head of Kinsale (25km) discovery in Block 49/23a. One appraisal well has been assumed to be drilled in 2010, suspended and completed with a second development well and first gas in 2012.

As nothing new has been presented by the operator, this remains a reasonable proposition for economic development but is predicated on the Old Head of Kinsale project, a tie-back to Marathon's Kinsale gas field, being developed. The apparent lack of progress on the Old Head of Kinsale development will impact directly on the potential for development of Ardmore.

Our estimates of oil and gas resources in the Ardmore discovery are:

Ardmore Discovery (49/14) – Contingent Resources			
	P90	**P50**	**P10**
Field Gross:			
Gas (BCF)	6	18	33
Net AP Resources (18.333% WI):			
Gas (BCF)	1.1	3.3	6.0
Total (MMBOE)	**0.2**	**0.6**	**1.0**

Note: In all tables the numbers have been rounded up

7.3 Helvick Discovery (Part Blocks 49/8, 49/9, 49/13, 49/14)

Helvick is a small oil discovery in Upper Jurassic sandstones on the north flank of the north Celtic Sea basin. Well 49/9-2 was drilled by Gulf in 1983 and discovered oil in two sandstone intervals as well as an underlying carbonate interval. The well was tested and flowed at cumulative rates of 9900 BOPD and 7.44 MMCFGD. Appraisal wells 49/9-3, 4, 6 and 6Zz, all either logged or flowed hydrocarbons from these sandstones.

The Helvick structure is an abutment closure, set against a down-to-the-basin, ENE trending, extensional fault. The Jurassic reservoirs are down-faulted and fault sealed against Lower Jurassic shales. The structure is fault sealed to the north and west and dip-closed to the south. The Main Sand is known to be laterally extensive in the local area. The structure is extensively faulted, resulting in numerous, small, fault bounded compartments.

The operator's estimate of oil in place for the Upper and Main sandstones is 8 MMBO. For the better quality and more continuous Main (deeper) sandstone they estimate a STOIIP of 4.5 MMBO. FRL have audited the operator's calculations and judge that the in-place volume estimates are a reasonable interpretation of the limited data available.

Well 49/9-4, 3kms west of the main discovery well, tested 1900 BOPD. The operator states that this well is in a separate accumulation, although from the mapping available to us, separate structures are not apparent. However, the reported fluid properties for well 49/9-4 are significantly different from the Helvick discovery well. The oil has a lower API gravity, 36º versus 42º API, and has 16% wax content. FRL conclude therefore, that this well is accessing a separate accumulation (Helvick Southwest) to the main Helvick discovery.

In addition to the Helvick Southwest discovery (well 49/9-4) there are prospects to the north of Helvick (West, NW and NE Helvick). From general inspection these prospects have merit but also significant technical risk, in particular in terms of reservoir presence. These prospects have not been evaluated in this report due to a lack of technical data but may provide some upside to the Helvick area.

Although the potential oil production rate from this discovery may be high initially, the small reserve volume, and extensive compartmentalisation requiring numerous wells, limits the opportunity for a commercial development. The recent lack of success with other appraisal activity in the immediate area reduces the likelihood of a regional development that could facilitate Helvick development. This would mean that any development of Helvick would need to be a standalone project. The partnership is currently looking at a number of innovative production options with the re-entry of the 49/9-2 and 49/9-6Z wells.

The Helvick discovery oil resource is estimated at 2.4 MMSTB at the P50 level.

8. UKCS Exploration Prospects

AP's UKCS exploration and appraisal prospects are principally in the Perth and Morecambe Bay areas.

8.1 North Perth Prospect (15/21c)

AP acquired its 3.75% interest in Blocks 15/21a, b and c from Premier Oil in 2003. The main issues for the Perth Field and adjacent area are structural complexity, reservoir distribution and high H_2S and CO_2 content of the reservoir fluids.

This un-drilled stratigraphic trap is a sand wedge, shaling out to the north, upthrown from the main Perth Field. Closure to the north and west is the sand pinchout and to the east is fault and synclinal separation from North East Perth.

North Perth is separated from the known accumulation of Perth by a potentially significant fault. The North East Perth (15/21a-7) oil discovery on trend is a positive indication that oil can occur north of this fault. The main mapping uncertainties are the pick for top sand and the northern extent of the sand wedge. Reservoir parameters are based on well 15/21a-7.

FRL estimate the technical CoS at 49% for an oil resource of 11 MMSTB.

8.2 East Perth Prospect (15/21a)

East Perth has the same trapping mechanism as the Perth Field area, to which it lies along trend to the east. This undrilled prospect has a sand pinchout to the north east, faulting to the north and dip closure to the south.
FRL estimate the technical CoS at 56% for an oil resource of 5 MMSTB.

8.3 Crosby Prospect (110/14d)

AP acquired a 25% interest in this licence as a member of the Challenger operated group that farmed into Burlington Resources' equity in August 2005. Prior to drilling the Crosby well, AP farmed down equity to 7.5%.

The Crosby prospect was drilled in June 2009 and was plugged and abandoned as a dry hole. The Sherwood sandstone came in deep to prognosis and was water wet.

In light of this, the partnership has agreed to relinquish Block 110/14d along with the West Lennox discovery during 2010.

9. Eire Exploration Prospects

9.1 Blackrock Prospect (48/30, 49/26)

Two dry holes surround this shallow prospect, well 48/30-1 approximately 7km to the west and 49/26-1A is just 2.5km to the south of the proposed location.

The structure is an ENE trending faulted anticline. The faults are strike-slip faults and the map shows very little vertical displacement. The main risk is likely to be fault seal; as even though the Wealden sands are thin, they may be juxtaposed across the faults.

The top of the Upper Wealden at the prospect location is mapped at almost the same elevation as the Upper Wealden in the dry well 49/26-1A. The relatively shallow depth makes low confining pressure and reduced fault smearing probable.

This prospect could contain oil or gas. However, FRL judge gas to be the more likely and have assessed the prospect as gas. On review of the available information from the operator, FRL judge 20 BCF gas resources to be representative for this prospect.

FRL have assumed the Blackrock development scenario is similar in nature to the Ardmore discovery, namely a sub-sea tieback to the Kinsale Head gas field (35km south of Blackrock) routed through the Old Head of Kinsale discovery in Block 49/23a. One appraisal well has been assumed to be drilled in 2010, with two development wells being drilled in 2011. First gas has been assumed to take place in 2012.

The CoS for this prospect is estimated at 21%.

It is anticipated that this block will be relinquished in early 2010.

10. Rushane Lead (48/29, 48/30)

The Rushane structure is an elongated anticlinal structure trending WSW-ENE, with significant faulting to the SSW. Well 48/30-2, drilled in 1992 on the crest of the structure, encountered 900ft of thin sands in the Wealden from 3103ft TVDSS. From petrophysical analysis, the current operator suggests the interval is hydrocarbon bearing and that there is a potential 20 MMBO oil resource.

No assessment of this lead has been undertaken due to a lack of data.

It is anticipated that this block will be relinquished in early 2010.

11. Faroes Exploration Prospects

11.1 Brugdan Deep Prospect (6104/16, 6104/21, 6105/25, 6105/30)

This prospect was identified following the post well assessment of the 2006 Brugdan well (6104/21-1), which was dry. Well 6104/21-1 drilled to a depth of 14,000ft before drilling was stopped due to ‘a fish in the hole’. The well encountered a much thicker volcanic interval than expected, but was not drilled deep enough to reach the prognosed secondary target.

The reservoir sands are now prognosed by the operator, Statoil, to lie beneath the TD of the 6104/21-1 well in the Brugdan Deep prospect. Although the mapped prospect has a large area, some of the other Statoil input values are, in FRL’s opinion, optimistic. The operator’s estimate of an unrisked 2 to 4.5 TCF is very optimistic.

Given the failure of well 6104/21-1, the geological risks assigned to this prospect are clearly high. FRL suggest a CoS in the region of 5%. Combining this with the remote location and cost of drilling this very deep target, FRL doubt if any activity on this prospect is likely.

The Faroese Ministry of Trade and Industry has approved a three years and five month extension of the licence 006, and the relinquishment of 58% of the licence acreage.

11.2 Licences L013 (6103/7b, 6103/8b, 6103/12, 6103/13 & 6103/17) & L014 (6104/9b, 6104/10b & 6104/14)

These two licences were awarded to Geysir Petroleum (operator) with 60% and AP with 40%, in the Faroes second round of licensing. The initial term was four years. The commitment was to purchase and reprocess existing seismic and acquire 1200km of new 2D seismic within the first three years. These were met and the licence has been continued into a second term for further work commitments.

The licences are situated in water depths from 2400ft (L014) to 4000ft (L013) on the East Faroes High, in an un-drilled area. From initial seismic interpretation and by analogy with the drilled areas to the southeast in UK waters, the presence of Palaeocene potential reservoirs and Jurassic source rocks can be expected. A significant risk is reservoir presence and quality for the sands below thick basalts. The operator/partnership believes that in L013 however, the volcanic section significantly thins and the partnership carries leads in this area. The ChevronTexaco 213/27-01 and 01Z Rosebank & Lochnagar intra-basalt and pre-basalt oil discovery (drilled in 2004) is 60km to the south.

Ten prospects have been identified in the two licences, eight in the Vaila Formation and two in the Flett Formation. The P50 STOIIPs range from 60 to 680 MMBO (although it must be noted that some of these structures do spill into adjacent blocks.

11.3 Licence L016 (6201/1a, 2a, 6a, 6202/4, 5, 6, 7, 8, 9, 10a, 11, 12, 13a, 14a, 15a, 16, 17, 18a, 21a, 22a, 6203/13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25)

The licences were awarded to Statoil Færøyene A/S (Statoil) with 50%, DONG with 30%, Føroya Kolvetni with 10%, and AP with 10% in the Faroes third round. The initial term was for three years with a commitment of 3200km 2D seismic and 175 attempted gravity sea-bed cores. The 2D seismic data was acquired and processing started in September 2009. The Kúlubøkan lead is to be worked up once seismic processing completed. The structure is large, having a potential reserve in excess of 1 BBOE. This potential is such as to outweigh the undoubtedly high risk that exists so that, if the lead does mature into a prospect, it would then likely be viable to drill.

Yours faithfully
For and on behalf of Fugro Robertson Limited

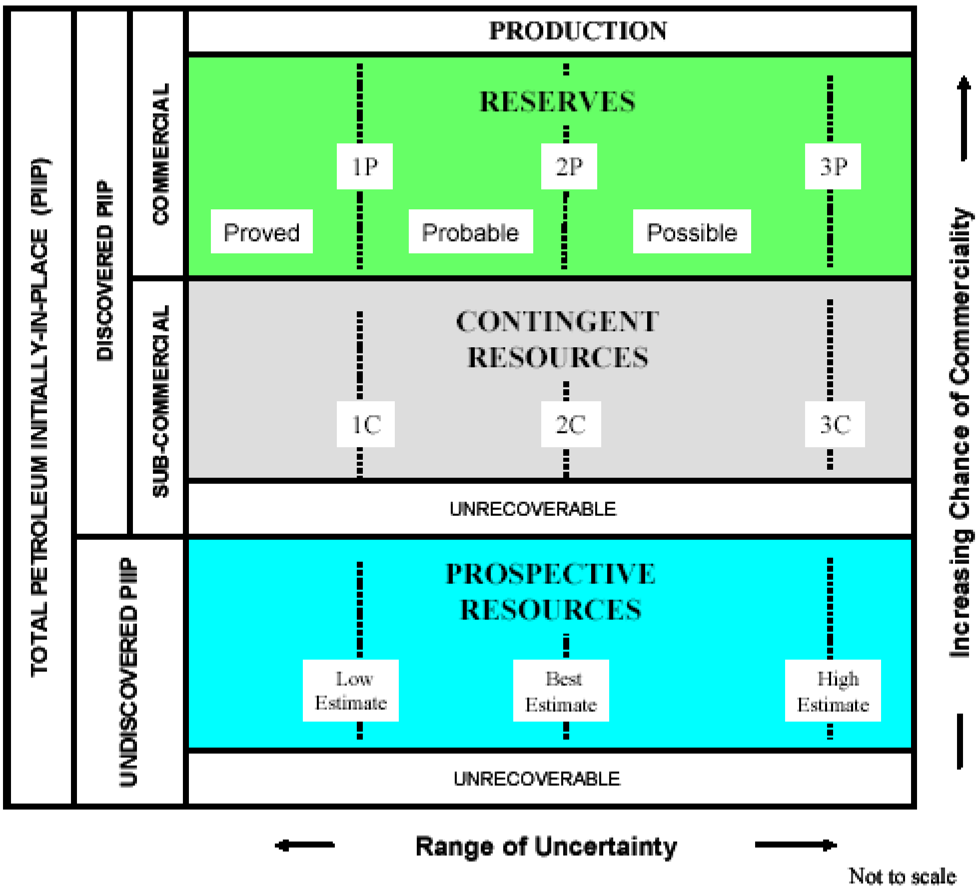
Andrew Webb
Deputy General Manager, Petroleum Reservoir & Economics Group

12. APPENDIX A: DEFINITIONS

12.1 Definitions

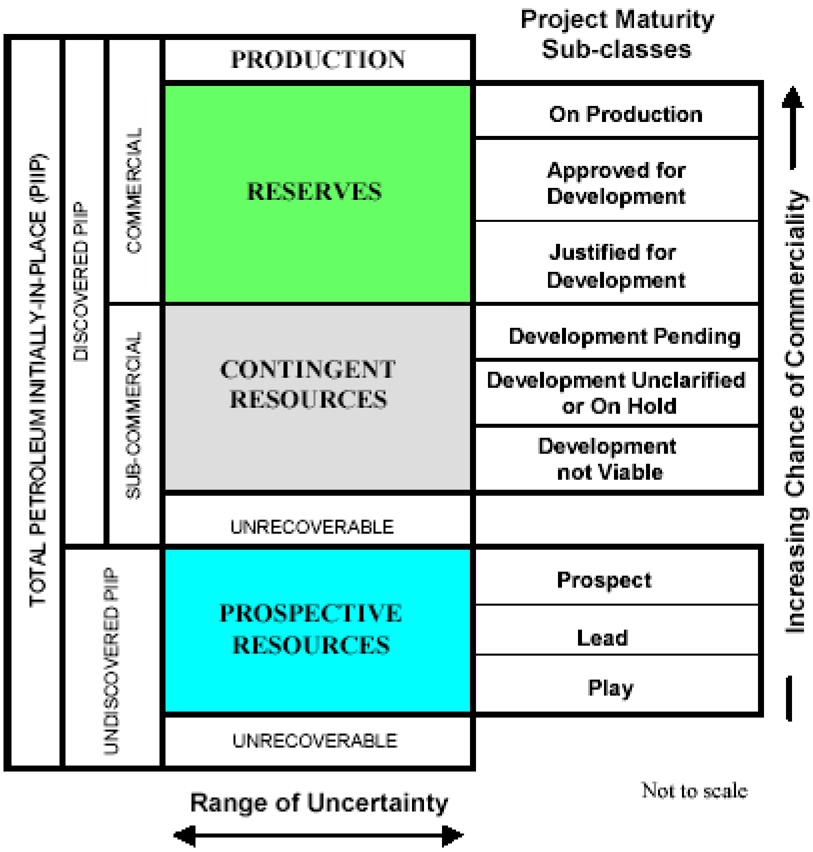
The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in 1998, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions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

Figure 12.1: Resources Classification Framework



Source: SPE Petroleum Resources Management System 2007

Figure 12.2: Resources Classification Framework: Sub-classes based on Project Maturity



Source: SPE Petroleum Resources Management System 2007

12.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

12.1.2 Discovered Petroleum Initially-In-Place

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

12.1.3 Undiscovered Petroleum Initially-In-Place

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

12.2 Production

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

12.3 Reserves

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations, from a given date forward, under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.

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

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

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

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

12.3.1 Developed Producing Reserves

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

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

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

12.3.2 Developed Non-Producing Reserves

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

Shut-in reserves are expected to be recovered from:

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

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

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

12.3.3 Undeveloped Reserves

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

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

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

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

12.3.4 Proved Reserves

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

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

12.3.5 Probable Reserves

Probable Reserves are those additional reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved + Probable Reserves (2P).

When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

12.3.6 Possible Reserves

Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved + Probable + Possible (3P), which is equivalent to the high estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

12.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

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

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

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

12.4.1 1C Contingent Resources: Development Pending

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

12.4.2 2C Contingent Resources: Development Un-Clarified/On Hold

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

12.4.3 3C Contingent Resources: Development Not Viable

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

12.5 Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. They are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

12.5.1 Prospect

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

12.5.2 Lead

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

12.5.3 Play

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

12.6 Unrecoverable Resources

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

13. APPENDIX B: NOMENCLATURE

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

MCFGD	thousand cubic feet of gas per day	phi	unit grain size measurement
mD	millidarcies	Ø	porosity
MD	measured depth	plc	public limited company
mdst.	mudstone	por.	porosity
MFS	maximum flooding surface	poroperm	porosity-permeability
mg/gTOC	units for hydrogen index	ppm	parts per million
mGal	milligals	psi	pounds per square inch
MHz	megahertz	RFT	repeat formation test
million m^3	million cubic metres	ROI	return on investment
ml	millilitres	ROP	rate of penetration
mls	miles	RT	rotary table
MMBO	million bbls of oil	S	South
MMBOE	million bbls of oil equivalent	SCAL	special core analysis
MMBOPD	million bbls of oil per day	SCF	standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
MMCFGD	million cubic feet of gas per day		
MMTOE	million tons of oil equivalent		
mmsl	metres below mean sea level	SCF/STB	standard cubic feet per stock tank barrel
mN/m	interfacial tension measured unit		
MPa	megapascals	SS	sub-sea
mSS	metres subsea	ST	sidetrack (well)
m/s	metres per second	STB	stock tank barrels
msec	millisecond(s)	std. dev.	standard deviation
MSL	mean sea level	STOIIP	stock tank oil initially in place
N	north	Sw	water saturation
NaCl	sodium chloride	TCF	trillion (10^{12}) cubic feet
NFW	new field wildcat	TD	total depth
NGL	natural gas liquids	TDC	tangible drilling costs
NPV	net present value	Therm	105 Btu
no.	number (not #)	TVD	true vertical depth
OAE	oceanic anoxic event	TVDSS	true vertical depth subsea
OI	oxygen index	TWT	two-way time
OWC	oil-water contact	US$	US dollar, the currency of the United States of America
P90	proved		
P50	proved + probable	UV	ultra-violet
P10	proved + probable + possible	W	West
P & A	plugged & abandoned	WHFP	wellhead flowing pressure
pbu	pressure build-up	WHSP	wellhead shut-in pressure
perm.	permeability	WD	water depth
PESGB	Petroleum Exploration Society of Great Britain	wt%	percent by weight
		XRD	X-ray diffraction (analysis)
pH	-log H ion concentration		