1st January 2009

The Board of Directors
Atlantic Petroleum
Gongin 9
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Faroe Islands

Dear Sirs

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

In response to your request, we 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 1st January 2009 and is based on technical data and information available and provided by AP up to 5th December 2008. This report documents the review of AP and comprises a Competent Persons Report ("CPR") for Danish and Icelandic stock market purposes.

1. Professional Qualifications

Fugro Robertson Limited ("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 we 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 has reviewed the assets of AP on a number of occasions. The last review was dated March 2008 and also took the form of a CPR.

Except for the provision of professional services on a fee basis, FRL has 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 1st 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 2nd 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.

2.2 AP Activity in 2008

During 2008 AP achieved first oil production from the Chestnut field and was involved in two successful oil discovery wells on the UKCS. Additional wells were drilled on Hook Head and Dunmore in the Celtic Sea that were not successful and the Ettrick development project suffered some development well results below expectations and various project delays.

The Chestnut field came on stream on 20th September 2008 and has since produced at an average rate of 10,500 bopd. AP received its first lifting of crude on 10th October 2008. In early November AP announced a successful oil discovery well on the South Chestnut prospective extension to the main Chestnut field. This well tested at maximum flow rate 8,200 bopd. The plan is to tie this into the Chestnut production facility in early 2009.

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

The Ettrick development has suffered both from delays on the FPSO delivery and some poorer than expected development well results. First oil is now anticipated late in the first quarter of 2009. The estimated Ettrick reserves have been reduced arising from re-interpretation of the reservoir with the additional well data.

In the Celtic Sea, the Hook Head appraisal well 50/11-4 was plugged and abandoned in late August 2008 after encountering gas shows. The Dunmore appraisal well 50/6-4 was suspended in late September 2008. The primary Upper Jurassic sandstone target was not hydrocarbon bearing although hydrocarbon shows were encountered but not tested in a Jurassic carbonate interval.

AP has been successful in both the recent Faroes and UKCS licensing rounds. In the UK 25th Licence round the company was awarded an interest in the 20/3f block adjacent to the recent Blackbird discovery. In the Faroes 3rd Licence round announced in December 2008 AP has been awarded a 10% interest in the L016 licence to the north-east of the Faroe Islands.

The UKCS P1211 licence containing the Anglesey prospect and the P1228 licence covering block 30/23b were relinquished in late 2008.

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,11,12,13 & 17	40%
Faroe Islands	L014	6104/9,10 & 14	40%
Faroe Islands	L006	6105/25 & 30, 6005/5a, 6104/16a,17a,21 & 26, 6004/1a	0.046%
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 below)
UK	P354	22/2a	15%
UK	P099	110/14c & d	25% (Note 1 below)
UK	P1478	110/9c & 14e	20%
UK	P1047	20/3c	17.5%
UK	-	20/3f	8.27%
Ireland	SEL 2/07	49/8,9,13,14,18,19, & 50/6,7,11 & 12	13.43%
Ireland	SEL 3/07	48/29, & 30, 49/22,23,26,27 & 28	13.43%
Ireland	LO 07/1	49/15, 50/7,8,11,12 & 13	13.43%

(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, such as Blackbird.

3. Data and Evaluation Basis

3.1 History

FRL has 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 1st January 2008 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 we have relied solely upon data supplied by AP. In particular we 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, we have used the standard techniques of petroleum engineering. There is uncertainty inherent in both the measurement and interpretation of basic geological and petroleum data. We 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. We have used the guidelines of Chapter 19 of the Listing Rules of the London Stock Exchange as a guide for the reporting standard but have also included the estimated value of exploration prospects.

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

We 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.

We have valued the petroleum assets using the industry standard discounted cash flow technique. In estimating the future cash flows of the assets we 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, we 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 will be tied back to the Chestnut field. The Ettrick development is at a mature stage and delayed first oil is now planned towards the end of the first quarter of 2009. We 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 1st January 2009 (MMboe)			
Field	**P90**	**P50**	**P10**
Chestnut & Chestnut South	0.6	1.5	2.4
Ettrick	1.2	2.5	3.9
Aggregated Total	**1.8**	**4.0**	**6.3**

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 we consider these assets to contain Contingent Resources.

We 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 1st January 2009 (MMboe)			
Discovery	**P90**	**P50**	**P10**
Ardmore	0.1	0.3	0.6
Blackbird	0.3	1.1	2.4
Bright	0.2	0.5	1.8
Dolphin	---	0.3	---
Gamma Central	---	0.4	---
Helvick	---	0.3	---
Hook Head	---	---	---
Marten	0.5	1.1	1.9
North East Perth	---	0.1	---
Perth	0.7	1.0	1.5
West Lennox	---	---	---
Aggregated Total	**---**	**5.1**	**---**

Of the five exploration and appraisal prospects that we have evaluated, three prospects are deemed to be economically viable to drill. We 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 1st January 2009 (MMboe)			
Prospect	**P50 Un-Risked**	**P50 Risked**	**Economically Viable to Drill?**
Blackrock Prospect (Part Blocks (48/30, 49/26)	0.4	0.1	No
Brugdan Deep Prospect (6104/16a, 17a & 21, 6105/25)	---	---	---
Crosby Prospect (110/14d)	3.8	1.6	Yes
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	**4.8**	**2.0**	**3 of 5 Prospects**

5. UK Production

AP has an interest in one producing field, namely Chestnut, which now comprises the main Chestnut field plus the recent extension discovery Chestnut South.

5.1 Chestnut Field (22/2a)

The Chestnut field was discovered in 1986 in 400 ft of water by the 22/2-5 well, which tested 6,500 bopd from a 67 ft interval of Eocene sands at 6,960 ft. Test rates were not stabilised, water production varied from 30-60%, and significant amounts of sand were produced. A second well, and sidetrack, 22/2a-7 & 7Z, tested 4,300 bopd from an 80 ft 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 550 ft reservoir section, and produced 1.05 MMbbls 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 7 to 121 ft (average 65 ft) thickness across the field. The reservoir is interpreted as an injectite sand, 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 MMbbls (P50). Our estimates of STOIIP range at 37.7 (P90), 48.4 (P50) and 58.1 (P10) MMbbls are similar to the Operator's current estimates.

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 in September 2008. Produced fluid is now being processed and oil stored on the floating production unit with oil export via shuttle tankers. Current production uses the existing well 22/2a-11X with pressure support to be provided via well 22/2a-12, drilled in 2007.

Since our previous review the focus of the Chestnut partnership has been on the execution of the development project, eliminating teething problems with the Hummingbird production unit, drilling of the South Chestnut extension and updating of the reservoir model.

Since the first oil production on 20th September 2008 Chestnut has achieved an average oil production rate of 10,500 bopd and a cumulative production of 1.1 MMbbls of oil to 31st December 2008. Production of water with the oil occurred after about one month of production and has subsequently been reported at very variable water-cuts. The Operator has been adjusting the performance of the well and the facilities in an effort, we presume, to optimise production performance.

With the commissioning of the Hummingbird facility ongoing the production monitoring data has not yet achieved a consistent reliability. However, based on the available data it is evident that there is a link between high oil offtake rates, the resultant lower downhole pressure, and rises in water-cut. In developing our estimates of field reserves we have assumed that the Operator will operate the field at a production rate optimised to maximise recovery rather than maximise short-term offtake rates, and that water injection volumes will be achieved as planned.

Although significant water volumes have been produced the overall oil and water production performance is reasonably in line with both the field development plan and more recent simulation studies completed by the Operator.

5.1.1 Chestnut South Extension (22/2a)

The southern lobe of the Chestnut field sand body was identified by the licensees as potentially containing a hydrocarbon accumulation and extension to the existing field. The lobe was successfully drilled during 2008 by well 22/2a-16.

The initial well, 22/2a-16 had to sidetrack due to shallow gas. The 22/2a-16Z well encountered a gas cap above the oil leg and was further sidetracked to a more easterly location (22/2a-16Y) where a fully oil bearing reservoir was encountered. Sixty four feet of net pay were penetrated vertically with an average porosity of 27%. The existence of a gas leg in the initial hole (also encountered previously in the 22/2a-7 well) highlights the potential existence of a more widespread gas cap. This may impact on future reservoir management as the Hummingbird production unit has only a very limited gas disposal capability.

Well 22/2a-16Y was confirmed to be in pressure communication with the wells in the main area of the field, establishing the South Chestnut area as an extension of the Chestnut field. The well tested at rates up to a maximum of 8,200 bopd and has been completed as a producer, but is not yet tied back to the Hummingbird. It is anticipated that the well will come on production in early 2009.

As a vertical well it is likely that the sustainable production rate from the 16Y well will be lower than from the 11X well to the north that is completed as a horizontal well. The life of field recovery from the 16Y well will be dependent upon the effectiveness of water injection pressure support.

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, including Chestnut South Extension

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

Chestnut Field (22/2a)			
	P90	**P50**	**P10**
Field Ultimate Gross Reserves:			
Oil (MMbbl)	5.0	11.0	17.0
Field Gross Production to 31-12-2008:			
Oil (MMbbl)	1.1	1.1	1.1
Field Gross Reserves at 31-12-2008:			
Oil (MMbbl)	3.9	9.9	15.9
Net AP Reserves (15% WI):			
Oil (MMbbl)	0.6	1.5	2.4
Total (MMboe)	**0.6**	**1.5**	**2.4**

6. UK Developments and Discoveries

Other than the Chestnut producing field, AP has interests in eight other UKCS petroleum discoveries, including Ettrick, 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 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 4,538 bopd. The field, which lies in 378 ft 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 560 ft gross thickness, comprises deep-water turbidites encased by shales within the Kimmeridge Clay Formation. The top reservoir is at 10,500 ft tvdss. The sandstone reservoir is vertically compartmentalised by extensive shale layers. The field oil water contact for the core area is interpreted at 10,605 ft. 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, at 23%, giving a net pay thickness of 70 ft in the crest of the structure thinning to 20 ft 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 3 new production wells and one injector well. The FPSO (Aoka Mizu) has been built in Singapore using a bare hull and is due to operate at Ettrick under a lease agreement. Development drilling commenced in 2007 and continued into 2008 and to date five wells have penetrated the reservoir with a sixth currently drilling.

A revised geological model has been developed by the Operator incorporating the results of the development drilling and regional sedimentological work. The model was not finalised at the time of this study, but we have reviewed draft output and are satisfied with the revised interpretation and subsequent volumes.

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, only 19 ft of net pay was encountered, 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 this well, the Operator has concluded that the core area of the field is much smaller than anticipated leading to a significant reduction in STOIIP compared to the sanction case.

Although the log data for well E1 were close to expectation, drill stem testing of this well was disappointing, with only modest rates and an early rate decline. We have reviewed the test interpretation and, although not definitive, the well behaviour is characteristic of a limited volume of good quality sand near the well but with relatively poor connectivity to the rest of the reservoir. This is consistent with our overall geological interpretation of the reservoir sands.

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 70 ft 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 4,500 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 supports the interpretation that the southern area of the field is located within a separate reservoir compartment to the core central area.

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 9,198 bopd of 36° API oil from the Halibut Dolomite. The overlying Turbot Dolomite tested 4,414 bopd of 38° API oil.

The currently drilling 20/2a-E6 well is targeted as both 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. At the time of this report the well has drilled through the Ettrick sands at the northern edge of the field core area where properties were approximately as prognosed. The well is due to enter the deeper Zechstein reservoir and be completed as a producer early in 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 2,400 bopd from this formation as well as producing from the Zechstein. However, the E6 well path for the currently drilling Jarvis target will not intersect the North Ettrick accumulation. Production for the North Ettrick (Ettrick sand) area will likely require a dedicated producer.

With very limited seismic available for review, 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.

Our estimate of STOIIP for the whole field in the light of the core area revisions, necessitated by the poor development drilling results, is 49 – 87 – 135 MMbbls compared to the Operator's estimate of 65 – 100 – 160 MMbbls. The STOIIP of the core area has reduced to 24 – 43 – 56 MMbls, compared to the Operator's sanction volume of 59 – 85 – 95 MMbls and current volume estimates of 40 – 59 – 81 MMbls. The Operator's current estimates for the additional volumes in the north and south of the field are in line with the original sanction estimates and are regarded as reasonable.

First production from Ettrick has been delayed from the original schedule. We have assumed a 1st April 2009 production start date for our valuation. We 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. Additional cost for these wells have being included in the estimated budget.

Our estimates of oil and gas reserves in the Ettrick field, including North Ettrick & Jarvis, after the economic cut-off, are:

Ettrick Development (20/2a, 20/3a)			
	P90	**P50**	**P10**
Field Gross:			
Oil Reserves (MMbbl)	13.7	27.7	43.6
Gas Reserves (Bcf)	4.8	13.1	21.8
Net AP Reserves (8.27% WI):			
Oil (MMbbl)	1.1	2.3	3.6
Gas (Bcf)	0.4	1.1	1.8
Total (MMboe)	**1.2**	**2.5**	**3.9**

6.2 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. We 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 a 8.27% interest in the newly awarded block 20/3f .

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 11,100 ft, 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 39 ft 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 3,850 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, 600 ft deeper than the Ettrick field. A further oil leg is also present in a deeper F Sand unit, but with only 18 ft 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 6 kms to the north. The latest Operator figures for in place volumes are a range of 36 - 50 - 69 MMbbls. 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 we have calculated a similar mid case in-place volume but with a more representative range of 16 - 54 - 120 MMbbls.

Preliminary simulation studies by the Operator have predicted a relatively low recovery factor. This work is clearly at a very early stage and implies a limited development of a complex sand and oil distribution. If the main Ettrick field development behaves as predicted then Blackbird should behave similarly, provided the necessary reservoir definition is obtained and sufficient development wells are drilled.

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. Further seismic mapping and an additional appraisal well are likely to be needed before a development commitment can be made. The Operator has reportedly initiated plans for a subsea tieback to Ettrick and has ordered some long lead items. However, this equipment is understood not to be dedicated to Blackbird and does not yet have partnership commitment.

We have assumed a successful 2009 appraisal followed by a subsea tieback to Ettrick. Development of the mid case reserve is likely to require two producers and two water injectors. First oil has been projected as October 2010 with an initial off take rate of 9,000 bopd.

Arising from the initial acquisition of the license covering block 20/2a, Premier Oil has a right to back-in to the license for a 5.515% interest in return for payment of AP's exploration costs. At present we understand that no decision has been made on this option. We estimate the oil and gas resources attributable to AP in the Blackbird discovery to be as follows. The first table assumes that Premier Oil does not exercise its right to back-in to Block 20/2a:

Blackbird Discovery (20/2a, 20/3a, 20/3f)			
	P90	**P50**	**P10**
Field Gross:			
Oil Reserves (MMbbl)	3.0	11.0	27.0
Gas Reserves (Bcf)	0.9	5.7	15.9
Net AP Reserves (8.27% WI):			
Oil (MMbbl)	0.3	1.0	2.2
Gas (Bcf)	0.1	0.5	1.3
Total (MMboe)	**0.3**	**1.1**	**2.4**

If Premier Oil exercises its right to back-in to block 20/2a for a 5.515% interest, we estimate the oil and gas resources attributable to AP in the Blackbird discovery to be as follows:

Blackbird Discovery (20/2a, 20/3a, 20/3f)			
	P90	**P50**	**P10**
Field Gross:			
Oil Reserves (MMbbl)	3.0	11.0	27.0
Gas Reserves (Bcf)	0.9	5.7	15.9
Net AP Reserves (3.307% WI):			
Oil (MMbbl)	0.1	0.4	0.9
Gas (Bcf)	0.0	0.2	0.5
Total (MMboe)	**0.1**	**0.4**	**1.0**

6.3 Marten Discovery (20/3c)

The Marten discovery well 20/3-4 drilled in 1984 found a 200 ft oil column in Buzzard equivalent sands at a depth of 11,000 ft.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.

Development of Marten is likely to be as part of a joint development with the nearby Polecat and Bright discoveries. All three discoveries contain similar, sour, crudes with high levels of CO_2 and H_2S in the gas stream.

There are no firm plans to develop Marten or Bright. However, once Ettrick production is on stream greater attention should be given to potential satellite developments in the area including this discovery. Also there is potential to tie back to Buzzard once its ability to process sour crudes is enhanced.

Our estimates of oil resources in the Marten discovery are:

Marten Discovery (20/3c) – Contingent Resources			
	P90	**P50**	**P10**
Field Gross:			
Oil (MMbbl)	2.5	6.0	10.0
Net AP Resources (17.5% WI):			
Oil (MMbbl)	0.4	1.1	1.7
Total (MMboe)	**0.4**	**1.1**	**1.7**

6.4 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 2,587 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 2.5 km 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 (MMbbl)	2.0	6.0	20.0
Net AP Resources (8.27% WI):			
Oil (MMbbl)	0.2	0.5	1.7
Total (MMboe)	**0.2**	**0.5**	**1.7**

6.5 Perth Discovery (15/21c)

The Perth field, lying in 475 ft water depth, was discovered in 1992 by the well 15/21b-47 that encountered 509 ft of oil bearing Claymore Sand. The well tested at 5,880 bopd of 30º API crude with 2.7 MMscf/d gas, which contained 36% CO_2 and 5,700 ppm H_2S.

In 1993, the eastern appraisal well 15/21b-49 encountered 858 ft of gross reservoir that tested 1,280 bopd. The field was further appraised by well 15/21-56 in 1997 for a 10 day EWT, which produced initially at 4,400 bopd, reducing to 3,700 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 12,000 ft.tvdss with the oil water contact at 12,993 ft.tvdss. Oil in place volume for the Perth discovery has been assessed in a number of studies during the past ten 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 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. This means that the current partners have until September 2009 to either initiate a development plan or relinquish the 15/21c block by December 2009. At present a firm development proposal has not been tabled by the Operator and partners to DECC.

For this evaluation a base development of three subsea production wells tied back to the Talisman operated Tartan field has been assumed. Should production performance justify it, water injection could be incorporated as a second phase of development. Gas is assumed to be used as fuel gas and no value is assigned.

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 (MMbbl)	17.1	22.8	34.2
Gas (Bcf)	15.6	20.9	31.3
Net AP Resources (3.75% WI):			
Oil & NGL (MMbbl)	0.6	0.9	1.3
Gas (Bcf)	0.6	0.8	1.2
Total (MMboe)	**0.7**	**1.0**	**1.5**

6.6 North East Perth Discovery (15/21a)

Well 15/21a-7, drilled in 1983, encountered oil bearing Claymore Sand. With 140 ft of pay, it tested 911 bopd of sour crude (1,400 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.

6.7 Dolphin Discovery (15/21a)

The Dolphin oil discovery was made by well 15/21a-46 drilled in 1992 that encountered oil in Claymore Sands at a depth of 11,100 ft.tvdss. The discovery had 93 ft of good quality sand in a 241 ft section with oil to the base of the section. The well flowed 3,245 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.

6.8 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, 950 ft above the Claymore Sand. The well encountered a 20 ft sand that tested 2,600 bopd of 25º API crude with no H_2S. The apex of the mound, with a predicted 250 ft of sand, is now mapped on the seismic along strike to the south-east.

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.

6.9 West Lennox Discovery (110/14c)

Well 110/14-1 was drilled on the West Lennox structure in 1990, and encountered a 25 ft oil column in the Sherwood Sandstone at 3,379 ft.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 54 ft 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. As the information from this appraisal well is being held confidential no reserve estimate has been made and no value is assigned to West Lennox. The plan is to re-assess West Lennox after the nearby Crosby prospect well is drilled.

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 104 ft of possible pay, with 68 ft of net pay between 1,180 and 4,748 ft.tvdss (Wealden Units 5, 4, 3 and 2). The well was not tested and the fluid type was not confirmed. 30° 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.

The field is interpreted as a domal structure of around 6,400 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 20 ft thick and encased in thick sections of shales and other non-pay sandstones.

Well 50/11-3 was drilled in 2007. The well 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 an unspecified depth.

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.

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.

We have not included Resource estimates in this report due to the lack of firm data that would allow us to calculate volumes 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 MMscf/d. The highest test rate of 4 MMscf/d was from the deepest tested interval at 5,520 ft. 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 MMscf/d, 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 we estimate a mid-case GIIP of 23 Bcf, compared to the Operator's estimates of 46.8 Bcf. We have assumed the Ardmore development is based upon a sub-sea tieback to the Kinsale Head gas field (48 km North East of Ardmore) routed through the Old Head of Kinsale (25 km) 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. This may not happen, however, which 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 (13.4304% WI):			
Gas (Bcf)	0.8	2.4	4.4
Total (MMboe)	**0.1**	**0.4**	**0.7**

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 9,900 bopd and 7.44 MMscf/d. Appraisal wells 49/9-3, 4 and 6 & 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 MMbbls. For the better quality and more continuous Main (deeper) sandstone they estimate a STOIIP of 4.5 MMbbls. We 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, 3 kms west of the main discovery well, tested 1,900 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 a 16% wax content. We 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.

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, Ettrick 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 pinch-out 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.

We 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.

We 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. We are advised that ConocoPhillips (formerly Burlington Resources) has an option to back into block 110/14d (Crosby prospect) for a 20% gross interest in the licence following a commercial discovery. Atlantic Petroleum's post back-in percentage will therefore be 20% and this is assumed in our evaluation.

The Crosby prospect is a "look-alike" for the Douglas field, 15 km to the southwest. Douglas produces 44º API oil from the Triassic Sherwood Sandstone. The Crosby structure consists of a series of north-south orientated tilted fault blocks, formed by extensional faulting in Triassic – Lower Jurassic times, and later adjusted into a broad dome by Tertiary inversion. Depth to the Sherwood sandstone is 4,000 ft.

The exact fault pattern is complex as the prospect lies at the edge of the current 3D coverage and the seismic data quality is poor. Contingent new 3D seismic is included in the work programme for the block. However, several interpretations by the Operator all show the same level of reserves. Any hydrocarbons could be oil or gas, which is likely to be sour, but is considered to be more likely to be oil given the similarities to the Douglas oil field.

Two structurally similar depth maps are available, by PGS (2006) and by Equipoise (2007). The main difference appears to be owing to the depth conversion and in particular the depth to crest of the structure. Also east-west trending faults in the north of the Crosby prospect are reported to be poorly imaged and the eastern edge of the reprocessed data sits close to the eastern boundary fault which required the use of 2D seismic data for its definition.

We have re-examined the Operator's risking and we conclude that this is a viable low risk prospect.

We estimate the technical CoS at 43% for a resource of either 35 Bcf gas or 15 MMbbls oil.

9. Eire Exploration Prospects

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

Two dry holes surround this shallow prospect, well 48/30-1 approximately 7 kms to the west and 49/26-1A is just 2.5 kms 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 Wealdon 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, we judge gas to be the more likely and have assessed the prospect as gas. From review of the available information from the Operator we judge 20 Bcf gas resource to be representative for this prospect.

We 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 2009, 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%.

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 900 ft of thin sands in the Wealden from 3,103 ft.tvdss. From petrophysical analysis the current Operator suggests the interval is hydrocarbon bearing and that there is a potential 20 MMbbl oil resource.

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

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 14,000 ft 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 as presented the mapped prospect has a large area, some of the other Statoil input values are in our opinion optimistic. The Operator's estimate of an unrisked 2 to 4.5 Tcf is, in our judgement, very optimistic.

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

11.2 Licences L013 (6103/7b, 6103/8b, 6103/11, 6103/12, 6103/13 & 6103/17) & L014 (6104/9, 6104/10 & 6104/14)

These two licences were awarded to Geysir Petroleum (Operator) 60% and AP 40% in the Faroes 2nd Round of licensing. The initial term is four years. The commitment was to purchase and reprocess existing seismic and acquire 1,200 km of new 2D seismic within the first 3 years. The group have acquired this 2D seismic data and the reprocessing has recently been completed. The partnership is currently interpreting the data with provisional maps expected in early 2009.

The Licences are situated in water depths from 2,400 ft (L014) to 4,000 ft (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 at a depth of 13,000 ft. below thick basalts of over 3,300 ft. The Operator/Partnership believes that in L013 however, the volcanic section significantly thins and the partnership carry leads in this area. The ChevronTexaco 213/27-01 & 01Z Rosebank & Lochnagar intra-basalt and pre-basalt oil discovery, drilled in 2004, is 60 km to the south.

Yours faithfully
For and on behalf of Fugro Robertson Limited

Andrew Webb
Deputy General Manager, Petroleum Reservoir & Economics Group

Appendix A - Petroleum Reserves & Resources Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers (SPE) and World Petroleum Congress (WPC) in 1998, supplemented with guidelines for their evaluation, published by the SPE in 2001. First, the definitions of Proved, Probable and Possible Reserves are presented, which reflect different levels of uncertainty associated with the technical estimates of petroleum reserves and resources. Secondly, the definitions are given of the categories of potentially recoverable volumes of petroleum accumulations according to their level of maturity or commerciality.

4.1 Proved Reserves

Proved reserves are those quantities of petroleum which, 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. Proved reserves can be categorized as developed or undeveloped.

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.

4.2 Unproved Reserves

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

4.2.1 Probable Reserves

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated Proved plus Probable reserves.

4.2.2 Possible Reserves

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated Proved plus Probable plus Possible reserves.

4.3 Reserve and Resource Categories

After discovery, petroleum resources may be assigned to one of the following two categories based upon their technical and commercial status at any point in time.

4.3.1 Reserves

Reserves are those quantities of petroleum that have been discovered that are estimated to achieve a commercial return on investment and have been approved for development by Government and the Board of Directors of the owners.

4.3.2 Contingent Resources

Contingent Resources are those quantities of petroleum, which are estimated, on a given date, to be potentially recoverable from known (discovered) accumulations, but which are not currently considered to be commercially recoverable.

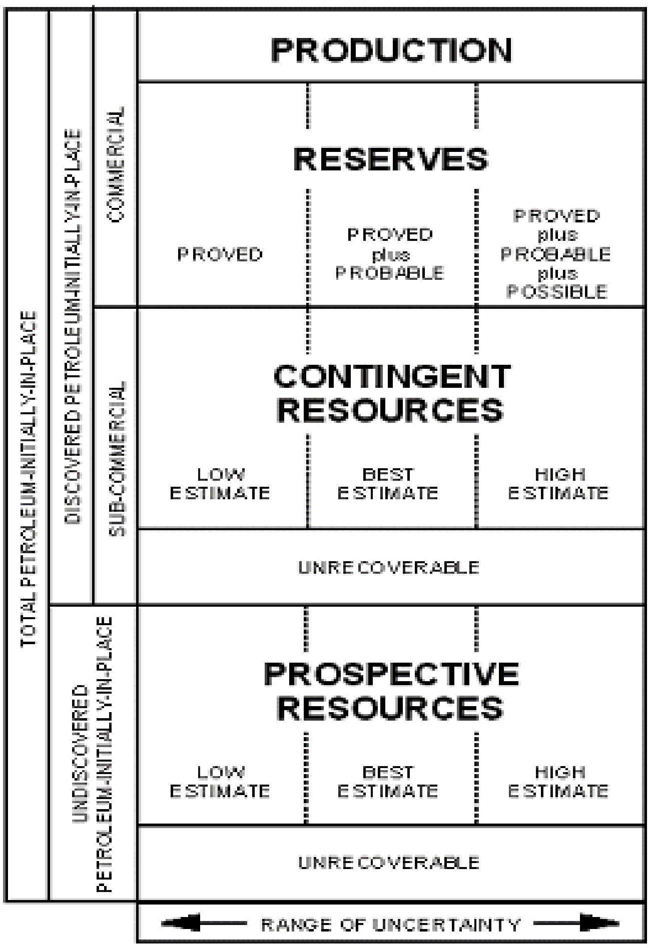
4.3.3 Prospective Resources

Prospective Resources are those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

4.3 Summary

The petroleum resource and reserve definitions are summarised in the following figure that has been provided courtesy of the SPE.

FIGURE 1 - RESOURCES CLASSIFICATION SYSTEM



Not to scale

Appendix B - Nomenclature

"bbl" means barrel(s) which is equivalent to 42 US gallons

"stb" means stock tank barrels, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit

"scf" means standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit

"boe" means barrel of oil equivalent, with gas converted at 1 boe = 5,700 scf

"bopd" means barrels of oil per day

"M", "MM" mean thousands and millions respectively

"GOR" means gas to oil ratio

"STOIIP" and "GIIP" mean stock tank oil initially in place and gas initially in place respectively

"Bscf" and "Tscf" means billion (10^9) and trillion (10^{12}) standard cubic feet respectively

"mD" means millidarcies

"Degrees API" means oil gravity in American Petroleum Institute (API) units

"Btu" means British thermal unit

"therm" means 10^5 Btu

"tvdss" means true vertical depth subsea

"ppm" means parts per million

"CO_2 and H_2S mean carbon dioxide and hydrogen sulphide respectively

"P90" means Proved for Reserves and Low for Resources

"P50" means Proved + Probable for Reserves and Central for Resources

"P10" means Proved + Probable + Possible for Reserves and High for Resources

"NPV (10)" means net present value at a nominal 10 %. discount rate using mid-year discounting

"CoS" means chance of geological and commercial success of an exploration or appraisal prospect

"IRR" means internal rate of return

"£" means pounds sterling, the currency of the United Kingdom

"$ US" means US dollar, the currency of the United States of America

"FSU" means floating storage unit

"FPS" means floating production system

"FPSO" means floating production, storage and offtake vessel

"ft" means feet

"m" means metre

"Km" means kilometre (1,000 metres)

"EWT" means extended well test

"RFT" means Repeat Formation Tester

"TWT" means Two Way Time

"NBP" means the UK National Balancing Point for natural gas

"LWD" means logging while drilling

"TCM" means Technical Committee Meeting

"OCM" means Operators Committee Meeting

"b/f" means brought forward

"ERD" means Extended Reach Drilling

"DECC" means Department of Energy and Climate Change

"EMV" means Expected Monetary Value