ISLE OF MAN. WHERE YOU CAN ADD NEW ENERGY TO YOUR BUSINESS
Why Isle of Man?

- Stable economy
- Well regulated international finance centre offering quick and easy establishment of new businesses
- The Island has an Aa1 Sovereign rating by Moody’s
- OECD White Listed
- Business-friendly, accessible Government
- Well established common law jurisdiction, providing legal stability and commercial legal certainty
- State of the art power, IT hosting and communications infrastructure
- Easily accessible from London, Dublin and major UK transport hubs.

Tax in the Isle of Man
- Competitive tax regime
- No withholding taxes on dividends or interest paid by a company
- 10% lower rate/20% top rate of personal income tax
- £125,000 annual maximum tax liability for an individual
- Integrated into EU VAT system via common purse agreement with the UK
- IOM Tax Authorities approachable and cooperative
- Forefront of efforts to put in place tax co-operation agreements, signing numerous TIEAs (Tax Information Exchange Agreements) and DTAs (Double Taxation Agreements).
- Complies with the EU Savings Directive

Key Points:
The Energy Sector enjoys a number of benefits in the Isle of Man:
- Location for opportunities in offshore energy
- Competitive tax regime
- Established infrastructure
- Existing Energy cluster
- International IP Treaties
- Established precision manufacturing sector
- Proven experience of trialling new technology
- Area for development of land and offshore
- Energy Funds domiciled on the Island
- Supportive Government policies

Contacts
Ken Milne
Director of Energy
Email: ken.milne@gov.im
Tel: + 44 (0)1624 687142

Department of Economic Development,
St George’s Court,
Upper Church Street, Douglas,
Isle of Man IM1 1EX, British Isles.
Tel: + 44 (0)1624 686400
[General Enquiries]

The Manx Electricity Authority combined cycle gas turbine power station in Douglas.
The Permian Gas Prospectivity of Block 112/25
Offshore Isle of Man

P. Cameron
August 2013
The Isle of Man has no proven conventional hydrocarbon reserves. There has been one gas discovery made in 1982 by BP Petroleum Development Limited in Block 112/25, which was at that time in UK waters but now lies within the Isle of Man 12 mile Territorial Sea limit.

Following an Out of Round licence award in 1996 from the Isle of Man Government, BP Exploration (Isle of Man) Limited (“BP”) (now dissolved) made further technical studies on the block (the BP Data) and gave a P50 number of 90 Bcf (billion cubic ft) of original gas in place for the discovery, with a further 800 Bcf in potential prospects and leads. To put these numbers into the context of Isle of Man energy independence, the Manx Electricity Authority in 2011-12 imported 3.5 Bcf of natural gas at a cost of £21 million.

There is a fundamental reason for the Oil Industry to overlook the potential behind the initial BP discovery. All gas production from the East Irish Sea Basin (EISB) including the prolific 5Tcf Morecambe field comes from shallower Triassic age reservoirs. The BP discovery was in deeper Permian age sands with poor reservoir properties. These Permian sands are absent over much of the EISB, which limits the data available on them. Only two exploration wells have encountered the sands in the NW section of the EISB and both found gas which is a good success rate. The results from the drill stem tests of these wells were not so good; the BP well failed to flow and the nearby Esso well tested at the low rate of 2 Mmscfd.

The BP results are still highly uncertain and based on limited seismic data with one control well, but what they do show is that there is a proven petroleum system in Manx waters which is worth further investigation. Reservoir presence is provided by the Permian age Collyhurst Sandstone, seal by the St Bees Evaporites and sourcing is from the Carboniferous. Traps are primarily faulted structures. BP relinquished the licence for economic reasons and because of reservoir delivery risks which were relevant issues back in 1996. Gas price increases since then have changed the economic argument and advances in drilling and completion techniques will allow tight gas sands to be put into production.

This report briefly looks at all hydrocarbon exploration in and around Manx waters before reviewing the BP activities in Block 112/25 in detail. The conclusions are that gas is present in the Permian sands, the prospects are larger than the estimates made by BP, a 3D seismic survey is needed to accurately define these prospects, and reservoir delivery can only be proven with another well.

Disclaimer
The BP Data which was prepared in 1996 was not prepared by, for or on behalf of the Department of Economic Development or its predecessors (“the Department”). To the fullest extent permitted by law the Department accepts no responsibility for the accuracy of the information, advice or opinion contained within the BP Data nor for any use thereof or reliance thereon.
Contents

Section 1  A summary of Hydrocarbon Exploration in and around Manx waters
1.1  Exploration Activity in Manx Territorial Waters
1.2  Basin Analysis
    Figure 1 Basin nomenclature
    Figure 2 Stratigraphic nomenclature

Section 2  A review of BP activity in Block 112/25
2.1  Chronological history of BP activities in Block 112/25
2.2  Well 112/25a-1
2.3  BP 1995 Out of Round licence application
2.4  BP 1996 Out of Round licence work program results

Section 3  Licence Relinquishment
3.1  Relinquishment decision
3.2  Risk factors
3.3  Economic consideration

Section 4  Reservoir Properties
4.1  Reservoir properties
4.2  Reservoir away from the 112/25a-1 well
4.3  Residual Gas

Figures 4 to 17

Appendix 1
Reservoir Delivery Study

Appendix 2
Petrophysical Interpretation

Appendix 3
An alternative estimate of Reservoir size, fault location and GIIP

Appendix 4
Hyde Field analogy
Section 1

1.1 Exploration Activity in Manx Territorial Waters

Figure 1 shows all the wells drilled in and around Manx waters by various oil companies since 1975. Three wells were drilled within the present day 12 mile territorial sea limit. The cluster of red shaded areas delineates the existing East Irish Sea gas fields in production; Millom field located partly in block 113/26 is the closest to Manx waters. The existing gas pipeline infrastructure is also shown.

![Map of Isle of Man 12 mile territorial sea limit, licence blocks, well locations, existing gas fields and gas pipelines.](image)

1.2 Basin Analysis

Refer to Figures 2 and 3 for the Basin and Stratigraphic nomenclature used throughout this report.

Peel Basin

The Peel Basin lies to the West of the Isle of Man. Elf drilled wells 111/29-1 in 1994 and 111/25-1 in 1996. Sherwood Sandstones were encountered and found to be water bearing. Both wells were unsuccessful because the entire Upper Carboniferous stratigraphy had been removed during a period of basin inversion and erosion. Consequently there is an absence of source rock potential in the basin to generate hydrocarbons.
**Solway Basin**
The Solway basin lies to the North of the Isle of Man. Elf drilled well 112/19-1 in 1997 and Esso drilled 112/15-1 in 1996. As with the Peel Basin, the Sherwood Sandstones were water bearing and the absence of Carboniferous source rocks significantly reduces the chances of a viable petroleum system.

**Eubonia Basin**
The Eubonia Basin lies to the East of the Isle of Man. Marathon drilled well 112/29-1 in 1996. The Marathon well found the Ormskirk Sandstone almost at the sea floor, Halite was absent from the well. This was also similar to the findings of Esso well 109/05-1 drilled in 1996 further south in the Godred structure. Both wells illustrate that any well drilled south of the Keys fault will most likely lack an effective seal to contain hydrocarbons. The Marathon well drilled more than 1000 ft of Collyhurst Sandstone before operations were halted and the well abandoned. The base Permian, top Carboniferous was not reached and no gas was seen during drilling.

**Ogham Inlier**
Cluff Oil drilled 112/30-1 in 1976. In this structure the Carboniferous lies at the sea bed. Gas shows and traces of dead oil were encountered, indicating that oil and gas have been generated and leaked from the top of the structure in the past.

**Lagman Basin**
The Lagman Basin is effectively the uplifted NW part of the Keys Basin. BP drilled 112/25a-1 in 1982. The well drilled into the Carboniferous and stopped at the top of the Dinantian. The Ormskirk Sandstone was found to be water bearing. The well also encountered 220m of Collyhurst Sandstone which contained a 48m tight gas column with an average porosity of 10%. A drill stem test was performed but the well failed to flow; permeability issues were the most likely cause of failure.
Figure 2  Nomenclature of the Permo-Triassic Basins and major faults around the Isle of Man.

The yellow shading identifies the Permo-Triassic basins around the Isle of Man. The area highlighted in red and bounded by the Lagman and Keys faults is the one area in Manx waters with the most potential for gas and contains the BP well 112/25a-1.
Figure 3  Stratigraphic nomenclature for the East Irish Sea Basin (EISB)

All hydrocarbon production in the EISB comes from the Triassic age Ormskirk Sandstone formation. The BP 112/25a-1 well encountered gas in the deeper Permian age Collyhurst Sandstone. The Millstone Grit is a Namurian age marine source rock for gas generated in the Keys Basin. Halite in the Mercia Mudstone provides a seal for the Ormskirk reservoirs, Halite in the St Bees Evaporites provides the seal for the Collyhurst reservoir.
Section 2

2.1 Chronological history of BP activities in Block 112/25

1972 Round 4 offshore UK licence P148 for block 112/25 awarded to BP

1982 BP drilled well 112/25a-1 which was plugged and abandoned.

1985 Licence expires and BP relinquishes the block.

1991 The Isle of Man territorial sea limit was extended to 12 miles which now includes block 112/25.

1995 BP applied for Block 112/19 off the Point of Ayre, as part of the first Isle of Man offshore licensing round. The block was awarded to Elf who subsequently drilled a dry hole in the Solway Basin along with two other dry holes in the Peel basin.

1995 BP applied for and were awarded by the Isle of Man Government an Out of Round licence for block 112/25 and the adjacent sections of blocks 112/30, 113/16 and 113/21.

1997 BP completed its technical study of the block and decided against drilling an appraisal well.

2001 Licence relinquished.
2.2 Well 112/25a-1

Well 112/25a-1 drilled by BP in 1982 is located in the area sometimes referred to as the Lagman Basin or Terrace; effectively it is the uplifted NW section of the Keys basin part of the EISB. The primary target was the Triassic Ormskirk Sandstone in the Sherwood Sandstone Group which was found to be water bearing. A deeper secondary target, the Permian Collyhurst Sandstone, was found to contain gas. The well was drilled into the Carboniferous and stopped at the top of the Dinantian. Total depth was 2778 mRKB.

During the drilling of the well, gas shows were seen above the top Ormskirk, in the Collyhurst and in the Carboniferous. One low porosity Carbonate formation in the Carboniferous had oil shows.

The well encountered 220m of Collyhurst Sandstone with poor reservoir properties; the Petrophysical Interpretation of the well shows the top 48m to be gas bearing with an average porosity of 10%. Top of Collyhurst was at 2052m TVDSS. They were unable to get pressure readings in the gas zone due to low permeability.

A Drill Stem Test was performed in an attempt to evaluate the Collyhurst. The test procedure involved running a 7” liner, cementing it in place and then perforating the entire gas interval in over balanced conditions using 4 shots per foot casing guns. Drilling mud was not circulated out and replaced with brine prior to perforating the well. The test string had a 1000m water cushion to give an initial drawdown of 2000 psi when the downhole tester valve was opened, no flow was observed at surface during a 4 hour flow period, although 150 ft of gas cut mud was found above the valve when the test string was pulled to surface. The test did not attempt to fracture the well.

Low permeability of the reservoir was the likely cause of failure.

The well was plugged and abandoned. Casing strings and conductor pipe were cut below the sea floor.
2.3 BP 1995 Out of Round licence application

Prior to the 1995 Licence application round, BP carried out a block specific evaluation of 112/25a-1 Permian gas discovery. They mapped the area using mainly 1988 and 1992 Jebco non propriety seismic surveys to delineate the gas discovery and identify three further Permian and four Triassic prospects/leads. Figure 4

Using well 112/25a-1 for time depth conversion BP created maps for the top Ormskirk, top Collyhurst and Geoseismic cross sections of the 2 seismic lines across the well; JS Manx 88-117 and 145, Figures 5, 6, 7, 8

From this information and the Petrophysical analysis of 112/25a-1 Figure 9, they produced some estimates for the potential gas in place for each of the prospects Figure 10.

In the 1995 Out of Round Licence application to the Isle of Man Government, BP proposed the following work programme:

1. Reprocess the seismic data to better map the prospects and faults and obtain revised gas in place numbers.
2. Reservoir deliverability studies; to evaluate the effectiveness of fracture stimulation and high angle wells on reservoir delivery.
3. Gas market study to look at the feasibility of using the gas as an energy source for the IoM. This was prior to the installation of the gas interconnector and Pulrose Gas Turbine Station.
4. Fund a Marine environment study with Port Erin Marine Lab.

And then at the discretion of BP

5. Make a 3D seismic survey of the area and drill an appraisal well. The well would likely be targeting the P1/P2 prospects.
2.4 BP 1996 Out of Round licence work program results

**Figure 11** shows the mapping of the Permian play fairway proposed by the BP Basin model. Gas generated in the Keys basin S, migrates to Collyhurst sands R which are bounded by the Keys and Lagman faults. Halite provides the seal C.

**Figure 11** illustrates the following points:
The Collyhurst is absent from the Millom and Morecambe fields in the central area of the EISB.

Halite has been deposited above the Collyhurst only over the NW section of the EISB. This makes the Collyhurst in Manx waters more prospective than anywhere else, but reduces the easy migration of gas into the Triassic Ormskirk.

The Esso well 113/27-2 which encountered 44m of Collyhurst is shown as having drilled into a separate area of Collyhurst deposition. This well produced at a rate of 2 Mmscfd from an open hole well test using coil tubing and nitrogen to lift the well into production.

The thickest Collyhurst sands are found further west as seen in 112/25a-1 and 112/29-1 with the best prospects likely to be the hanging walls of the Lagman and Keys Faults.

**Seismic reprocessing and revised Gas in Place numbers**

The aim of the seismic reprocessing was to enhance fault imaging, improve the top reservoir definition and obtain revised gas in place numbers. In addition limited offset stacks, depth migration, acoustic impedance studies were made on several lines but did not yield further useful results.

**Figure 12** shows the reprocessed mapping of the top Collyhurst. A white dot marks the location of 112/25a-1 at the intersection of seismic lines JS Manx 88-117 and JS Manx 88-145. The well was drilled into the Collyhurst in close proximity to a fault. BP has inferred that it intersects this fault after drilling through 190m of Collyhurst formation.

**Figure 13** shows a seismic cross section sketch of **Figure 14** JS Manx 117 and illustrates how the 112/25-1 well intersected the Collyhurst at a sub-optimal location, i.e. adjacent to a fault and in the gas water transition zone. Discovery D is shown as a sloping formation extending up to 1500 m where it reaches the Lagman fault.

Two prospect models are proposed for the block in **Figure 13**, the location of a gas water contact will determine if model A or model B is valid. Model A is highly prospective since it does not require a seal against the major faults.

**Figure 15** shows the calculated volume of Gas Initially in Place (GIIP). The 90-50-10% probability numbers are shown. The P50 numbers calculated by BP are 90 Bcf from Discovery D, between 120 to 550 Bcf from prospect model A/B and 250 Bcf from lead C.
Reservoir Deliverability studies

The aim of these studies was to evaluate well stimulation and completion techniques to improve the reservoir delivery of the Collyhurst.
- Acidising the well for skin damage removal
- Hydraulic fracturing to overcome the low permeability seen in 112/25a-1
- Assess the use of high angle wells to improve drainage

The BP analysis of the 1125/25a-1 well test results could not provide accurate calculations since there was no flow other than gas cut mud found inside the test string. BP estimated that the maximum rate was 0.5 Mmscfd with a maximum formation permeability of 0.2mD

The conclusion was that if the 112/25a-1 well was representative of the reservoir then development was not feasible. If the reservoir properties found elsewhere in the area were better than the discovery well and permeability was instead found to be in the order of 1-2mD, then development was feasible using fracturing or horizontal wells to obtain a 40 to 65% recovery factor.

The computed output of a delivery study made at the time is included in Appendix 1 to illustrate the potential well delivery rates. This study shows the calculated results of rates versus bottom hole flowing pressures for various horizontal wells and one fractured well. In addition to data from 112/25a-1, the study has to make a large number of assumptions for the reservoir parameters. This is a single phase study and does not deal with the issues that would arise from any associated water production.

The industry has moved on since the 1996 study was made, advances in drilling and completion techniques such as massive hydraulic fracturing, multilateral completions and horizontal wells combined with multi-stage fracture stimulation have enabled tight gas sands with low permeability to be developed. The nearby Millom field is one such example with average permeability of 0.2mD and with porosities in the range of 6 to 11%.
Section 3

3.1 Relinquishment Decision
In a 1997 presentation to the Isle of Man Government, BP stated that the discovery and prospects were
“Not economically attractive
-discovered volume small
-risk on reservoir delivery high
-cost of standalone development too high”

3.2 Risk Factors

The risk factors were summarised by BP in the table below.

Factors labelled probable refer to Prospect Models A & B since these are already proven for the Discovery. Deliverability can only be proven by performing another test in a different part of the reservoir.

3.3 Economic Considerations
The price of UK natural gas in 1996 was in the range of 10 to 15p a therm. Since then there has been a fivefold increase in the price for gas, in 2012 the MEA were paying between 50 and 65p a therm.

To get an idea of the value of the potential reserves at current gas prices, the Discovery has GIIP of 90 Bcf and with a 50% recovery factor would produce 450 million therms valued at £250 m if sold at 55p/therm. This is still a marginal field for an Oil Company operating in UK waters since they would be looking at around a 60% taxation rate on the gas produced. It may be of interest to the current Millom Field Operator if a subsea tie back to the platform was a feasible option. It should also be of interest to a Government entity like the MEA if tax were not raised on the gas produced.

Discovery A plus prospect Model B has 640 Bcf GIIP and with a 50% recovery rate would produce 3,200 million therms valued at £1.8 billion; this would justify a standalone development with its own platform and production facilities.
Section 4

4.1 Reservoir Properties

The reservoir properties seen in the gas zone of 112/25a-1 are not good and are a high risk factor to any future program. Diagenetic effects from cementation, illite, salt and compaction due to burial are all possibilities which may have contributed to the loss of permeability. Burial was down to an estimated 4km prior to uplift to the present day depth. A core was not taken from the well.

Zero separation of resistivity curves in the gas zone indicates no invasion of drilling fluids and zero flow on test indicates that both the gas and water phases are immobile.

A model for this type of behaviour in tight gas sandstones can be found in the 2010 paper: Relative Permeability in Tight Gas Sandstone Reservoirs - The “Permeability Jail” Model. Robert M. Cluff, The Discovery Group Inc., 1560 Broadway Ste 1470, Denver, Colorado, USA Alan P. Byrnes, Kansas Geological Survey at the University of Kansas, now with Chesapeake Energy Corporation, 6100 N. Western Avenue, Oklahoma City, Oklahoma, 73118 USA

Download link: http://www.discovery-group.com/pdfs/2010_LLLL.pdf

The paper also includes a relevant example of an early age gas charge followed by burial and uplift resulting in an extended transition zone.

We could expect to see fluid mobility and Krg increasing if water saturation decreases updip of 112/25-1.

4.2 Models for better reservoir properties away from 112/25a-1

A more optimistic view for the Collyhurst as a reservoir rock is that the well intersected the reservoir by chance at the worst possible location and that the reservoir properties are going to be better elsewhere.

Figure 16 illustrates 3 possible concepts suggested by BP which could give better reservoir properties away from the 112/25a-1 well.

- Relative permeability. The 112/25a-1 well drilled into the gas water transition zone, the permeability up dip would be higher in zones of lower water saturation. This is a similar concept to the model described in the paper above.

- Early Gas charge. Illite diagenesis seen elsewhere in the East Irish Sea basin would not occur in rock already filled by an earlier age gas charge, an example would be the nearby Morecambe field.

- Fault damage. The well drilled into a fault in the Collyhurst and could therefore be affected by formation damage related to fault diagenetic effects.
There are also three other direct observations which show better properties for the Collyhurst as a potential reservoir rock.

1. The porosity and permeability within the 112/25a-1 well itself: below the gas water contact there are sand intervals with higher porosity and permeability than in the gas zone of the well. The density neutron shows higher porosity and an open hole pressure test made at 2175 m showed good permeability, and gives us the reservoir pressure of 3432 psi at this depth. These sands will be above the gas water contact updip of 112/25a-1.

2. South of the Keys Fault in Marathon well 112/29-1 the Collyhurst shows good porosity and permeability at 1000m depth, Hydrocarbons were not encountered in this well probably due to the absence of halite as a seal, but the open hole logs show around 10 to 16% porosity and the resistivity curves show fluid invasion indicating permeability. In addition there is a core from the Marathon well which gives porosities in the range of 10 to 17% and permeabilities in a wide range up to 65 mD. The Marathon well gives a view of the Collyhurst properties for 112/25a-1 prior to burial when it could have accumulated an early gas charge.

3. The Collyhurst at 1750m in Esso 113/27-2 shows similar porosity with higher permeability. This well had gas in the Collyhurst and when tested, flowed 2 Mmscf/d gas from a 44m interval. Sw was around 40% in the gas zone. In this well, the test was performed as an open hole DST using coiled tubing and nitrogen to get the well to flow. A short 13ft core was taken from the Collyhurst reservoir which included both sand and shale strata, of which the best sandstone porosity was 14% with 50mD permeability.

4.3 Residual Gas

Due to the low permeability of the reservoir, open hole formation pressure tests attempted in the gas zone were unsuccessful and the well failed to flow during the drill stem test. Therefore the possibility of residual gas has not been eliminated. BP regarded the trap integrity as proven and described the discovery as containing live gas and not residual gas. Experience with other low permeability sandstone reservoirs and the expected water saturations for this type of reservoir would influence this conclusion.
Isle of Man, Out of Round Licensing

Prospect Location
Blocks 112/25, 113/16, 113/21 and 112/30

Figure 4
Figure 5
Figure 6
Figure 7
Figure 8
Petrophysical Analysis of Permian Reservoir for 112/25a-1

Figure 9
Figure 10

Total Permian (Bcf)
690 - 1250 - 2300

Total Triassic (Bcf)
220 - 320 - 470
Figure 12

March 1997
Block 112/25 GIIP volumes (P90-P50-P10)

Discovery ‘D’
60-90-120Bcf

Prospect (Model ‘A’)
80-120-150Bcf

Lead ‘C’
P50 ~ 250Bcf

Prospect (Model ‘B’)
350-550-750Bcf

Figure 15
Models for better rock quality away from 112/25a-1

Relative Permeability Effects

Keys Fault

112/25a-1

lower Sw, higher Krg
up dip of 112/25-1

112/25-1 contains thin (50m) gas column in the transition zone

Early Gas Charge (cf. Morecambe)

Keys Fault

112/25e-1

early gas charge restricted cementation and preserved rock quality

Could also be fault related damage

0.1

permeability

100mD

well penetrates fault at base of reservoir

damage zone extends 10-100m away from fault

March 1997
Appendix 1.1
Reservoir Delivery Study

THoR has been used to calculate the pseudo-steady state inflow for various well configurations based on data from Isle of Man Well 112 / 25a. Comparisons of the performance of horizontal wells with different lengths to that of a propped fractured well are made. The following data has been used in the calculations:

**Gas PVY Data**
- Gas viscosity at Average Reservoir conditions: 0.0180cp
- Z at Average Reservoir conditions: 0.95

**Reservoir Parameters**
- Reservoir thickness: 100ft
- Effective horizontal permeability: 0.2mD
- kv/kh: 0.05
- Nominal well bore diameter: 8.5in
- Reservoir temperature: 140°F
- Reservoir pressure: 3550psi
- Boundary condition: Pseudo steady state
- Boundary pressure: Average
- Drainage radius: 640acres

**Fracture Data**
- Fracture half length: 500ft
- Fracture conductivity: 300mDft

The results have been compared with the Stimplan runs and show similar performance for the hydraulically fractured case.

Figure xx shows the predicted performance of a fractured well and horizontal wells of various lengths. The longer horizontal wells perform better than the hydraulically fractured well. This is largely because the formation thickness is low and a moderate value of vertical permeability has been used (1mD). Performance is still likely to be below economic levels.

Figure yy shows the effect of varying the vertical permeability on the performance of a 3000ft horizontal well. This gives an indication of the likely effect of multiple hydraulic fractures in a horizontal well and shows that higher rates are achievable, but that the rates are still unlikely to be un-economic.
Appendix 1.2

Comparison of the Performance of Horizontal Wells of Various Lengths with a Hydraulically Fractured Well

The Effect of Changing \(k\)\(v\)\(kh\) on Horizontal Well Performance
Appendix 2.1
Petrophysical Interpretation

<table>
<thead>
<tr>
<th>DEPT (FT)</th>
<th>Summary</th>
<th>Resistivity</th>
<th>Salinity</th>
<th>Matrix</th>
<th>Porosity</th>
<th>Lithology</th>
</tr>
</thead>
<tbody>
<tr>
<td>6700</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6800</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6900</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7100</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7200</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7200</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

August 2013
**Appendix 2.2**

Notes:

Petrophysical Interpretation recomputed in 2013. Depth units in ft.
Gas zone shows 40% gas saturation with average porosity of 10%.
Sxo/Sw overlay in the gas zone shows fluids to be immobile.
Pure halite directly above the reservoir.
Reservoir properties for the upper sands show improving trend as distance increases from the top of the reservoir.
Sands between 7110 to 7140 ft below the gas water contact show the best reservoir properties.
Appendix 3.1

So far this report has been stating the BP activities and their findings. This appendix considers the uncertainties over the location of the fault intersected by the 112/25a-1 well and the Collyhurst reservoir size. An alternative model based on the existing data is examined which changes reservoir size, fault location and GIIP numbers. This section reinforces the need for 3D seismic to better define the reservoir structure of the discovery and surrounding prospects.

1 An alternative estimate of the Collyhurst Reservoir size and the fault location

There is some considerable uncertainty over the identification of events below the St Bees Evaporites on the seismic maps. The base Permian/top Carboniferous horizon has not been marked on seismic cross section JS Manx 117 Figure 14. The red horizon is the deepest reflector which could be reliably mapped within the Collyhurst over most of the block. Even though the 112/25a-1 well encountered 220m of Collyhurst formation, only 90m has been used by BP as the reservoir thickness for the GIIP calculations of Discovery D and Prospects A/B. Lead C used a 50m thickness. The lower fluvial sands were not counted towards the volume calculations.

The BP interpretation of seismic and well data assumes that the base of the Collyhurst is fault controlled and the well encounters the Carboniferous by crossing the fault.

Figure 17 is the Petrophysical Interpretation of the well. The top of the fault zone is marked at 2243m. The area labelled as the fault zone appears to be a formation with increasing Dolomite content. The top Carboniferous can be identified from a sharp increase in the Gamma Ray and is shown at 2272m.

From the well data there is some evidence for a possible alternative location for the fault marked at 2243m on Figure 17. A four arm dipmeter was used in the well and from it a 180 degree shift in dip azimuth can be observed across the reservoir.

Above 2096m in the gas zone the formation dips 10 deg SW
Between 2096m and 2144m no discernible dip direction
Below 2144m the formation dips 10 deg NE
There is little change in dip azimuth or angle between 2243m and the top of the Carboniferous .

The above depths are corrected to MSL to tie in with the seismic depths. The structural dip angle and azimuth in this well are clearest to see on the field computation log. This feature is less clear on the computing centre Cluster results since the program is also plotting all the low confidence dips to assist more detailed stratigraphic interpretation.
Appendix 3.2

These results should be viewed in the context of Figure 8 Geoseismic cross section of JS Manx 88-145 which runs SW to NE showing the well adjacent to the fault. A 180 deg shift in azimuth would be explained by the well crossing the fault at 2144 m.

The sand itself at 2144 m is clean with almost no porosity (possible quartz/cemented channel) and this appears out of place compared to the porous sands above and below. The BP studies have identified this as the point where the sands change from Aeolian to Fluvial in origin with paleo wind and current directions accounting for the azimuth reversal.

There is some conflict between the various seismic interpretations made showing the dip of the Collyhurst formation around the well bore and above the fault intersect. Geoseismic Cross Section JS Manx 145 Figure 8 shows dip to the SW, the Sketch Cross Section JS Manx 117 Figure 13 shows dip to the SE and from the seismic line JS Manx 145 in the post licence studies, the horizons are drawn dipping to the NE. However the following features can be observed directly from the original processing of the seismic lines:

JS Manx 117 has a relatively flat horizon around the well bore in the Collyhurst adjacent to the fault. JS Manx 145 is more complicated but it does appear to show SW horizons adjacent to the fault which could be related to the expected drag effects along the fault.
Appendix 3.3

The sketch cross section of JS Manx 117 Figure 13 is shown below and has depths from Figure 17 added. The top Collyhurst from the 1996 reprocessed seismic is at 1800m for Prospect model A. An additional red line has also been added to show the well crossing the alternative fault location at 2144m.

If the alternative fault location is correct then the Collyhurst will be around 470m thick. Since the thickness of Collyhurst for Discovery D and Model A will be the same across the fault, it also follows that Discovery D Collyhurst will be around 470m thick. The shorter reservoir encountered by the well implies that the Permian includes sections from both sides of the fault.

The sketch illustrates the Collyhurst in 112/25a-1 as having an upper Aeolian section from Discovery D and a lower Fluvial section from Prospect Model A. The full extent of the Aeolian sands is unknown but would be more than 90m and up to a maximum of 344m (2144-1800m).
Appendix 3.4

The 470m calculated above does not seem out of line with the size of Collyhurst seen in the Marathon well South of the Keys Fault. This well drilled through 311m of Collyhurst before drilling was halted and the well abandoned; since there was no indication of reaching the Carboniferous, we do not know the full extent of the Collyhurst in the Marathon well.

To add to the uncertainty and to consider other possibilities, an alternative way to interpret the 180 deg shift in dip azimuth is to assume there is some kind of fold adjacent to the fault as in the sketch below.

Notes:

1. The BP Palynostratigraphy report for the well concludes the base Permian is deeper than that seen from the wireline logs at 2272m. The report gives the following depths:
   1952m to 2457m late Permian
   2502m first evidence of the Carboniferous.

2. Depths being used here have been corrected to Mean Sea Level to match the seismic. Measured depths are referenced from Drill Floor elevation which is 38.1m above MSL.
Appendix 3.5

Density Neutron from 112/25a-1

Clean sand/quartz at 2180 mRKB has almost zero porosity and is the point below which the reservoir azimuth shifts 180 deg.

The Gas effect is clearly seen above 2134 m, where Sw is calculated at 60%.
Appendix 3.6

2 Revised GIIP calculation

It has been stated earlier that the Collyhurst could be 470 m thick so it is of interest to see how that would affect the GIIP numbers for the discovery reservoir. The probabilistic computer model and the data set used by BP to calculate GIIP volumes are not available. A simpler approach has to be taken to get an estimate.

In the 1995 licence application BP estimated that the Discovery had a P50 GIIP number of 260 Bcf. Following the licence work studies they had reduced this number to 90 Bcf, a significant reduction which made the discovery uneconomic for any kind of development at that time.

The numbers which were used by BP in the calculation of GIIP can be examined in order to work out what caused such a large downgrade.

Pre licence numbers to calculate GIIP of 260 Bcf
Reservoir Thickness = 220 m
Reservoir Gross volume = 1626 x10E6 m3
Porosity = 8%
Net/gross pay = 50 %
Gas saturation = 65 %
Gas expansion factor = 215

Post licence numbers to calculate GIIP of 90 Bcf
Reservoir Thickness = 90 m
Surface Area = 5.3 km2 (from the GIIP map Figure 15)
Reservoir Gross volume = 470 x10E6 m3 (calculated)
Porosity = 10%
Net/gross pay = 70 %
Gas saturation = 40 %
Gas expansion factor = 200

The largest change has been reservoir volume. The reservoir surface area is reduced on the reprocessed seismic and only the top 90m of Aeolian sands are used for the GIIP calculations. Pre licence, the Fluvial sands were included with a reduced net/gross number. The other large change has been gas saturation. 40% post licence versus 65% pre licence. The 40% figure is the correct number for the gas zone of 112/25a-1 (confirmed by Appendix 2 results) and should increase updip and away from the transition zone of the reservoir. 6% porosity was used as the cutoff for the pay zones.
Appendix 3.7

A basic formula will be used to calculate GIIP

GIIP = Area x thickness x porosity x net/gross pay x (1-Sw) x expansion factor x (m3 to ft3)
Where Sw is the computed water saturation

To check this simple formula gives reasonable figures, we can use the BP post licence numbers for the Discovery to calculate gas in place for the 90m reservoir column.

GIIP = 5.3 x 90 x 0.1 x 0.7 x 0.4 x 200 x 35.3 = 94 Bcf

This is close enough to the P50 number of 90 Bcf calculated by BP to validate the approach.

To calculate the volume of the sloping 470m reservoir in Discovery D another very basic approach is taken. A 1.8 km by 3.8 km ellipse encloses the discovery and gives a reasonable estimate of the surface area. Since the top of the reservoir is at 1500m and the gas water contact is at 2100m, an approximate volume figure can be found to use in the GIIP calculation.

Discovery D superimposed with an ellipse 1.8 km x 3.8 km
Area 5.3 km²

Simplified view of Discovery D reservoir represented as elliptic cylinders
Calculated vol 1720 x10E6 m³
Appendix 3.8

For the new estimate of GIIP

Reservoir Gross volume = $1720 \times 10^6$ m$^3$
Porosity = 10%
Net/gross pay = 50% (reduced from 70% since we include fluvial sands)
Gas saturation = 40 %
Gas expansion factor* = 204 (calculated below for 90% methane)

GIIP = $1720 \times 0.1 \times 0.5 \times 0.4 \times 204 \times 35.3 = 248$ Bcf

If 60% gas saturation is used instead of 40%, the GIIP for the discovery becomes 372 Bcf.

These numbers are large and perhaps over optimistic, but the point of the exercise is more to illustrate the potential size of the discovery reservoir rather than come up with an exact figure.

The most prospective target remains Model A since it does not require a lateral seal against a major fault and is enclosed by halite on all sides.

*Gas expansion factor between reservoir and surface conditions = 204
(The reservoir pressure & temperature is available from the open hole data, calculated Gas Formation Volume Factor = 0.8727E-3 and calculated gas deviation factor = 0.83 for a 90% methane gas mix)
Appendix 4.1

Well 47/5a-2 Hyde Field as an analogy to BP 112/25a-1.
Low permeability Permian age Sandstone Reservoir.
First North Sea Field put into production using horizontal well completions.
Water Saturation no lower than 40% at the crest of the reservoir structure.
Pre and post fracture production rates for the appraisal wells are given in fig 4.
Appendix 4.2
Appendix 4.3

Fig. 3. Cross-section along the axis of the field. The plunge of the structure to the northwest is clear. The diagram also shows the facies change in the upper part of the reservoir that occurs in Block 47/5a. Neoplastic layers with reasonable quality rock in Block 48/6 pass laterally into sandy sabkha facies with very low permeability in Block 47/5a. This effectively confines the core development area of the field to the southeast end of the section.

Fig. 4. Facies correlation of the stratigraphic and geographic core area of the field. The layering of the reservoir is of a scale and continuity that can be targeted with horizontal wells. The primary targets of the 48/6-34Z well (which twinned 48/6-26) were zones 4A2 and 4B2.