FORESIGHTING REPORT

Addressing the technology needs and defining the commercial opportunities in Improved Reservoir Imaging

Improved Reservoir Imaging

For Members only

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V1.0

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EXECUTIVE SUMMARY

The annual spend on geophysical acquisition, processing and interpretation is $7 billion with the bulk of this expenditure on seismic acquisition.

Despite this level of investment and recent advances in seismic technology, exploration and development well failure rates still cost the industry around $26 billion/yr. Unless reservoir imaging can improve, the cost will increase as the proportion of more costly deepwater wells increases.

Around 1.7 trillion boe of discovered reserves remain to be produced with an estimated 1.8 trillion boe of conventional resources still to be discovered. An improved ability to identify the distribution of these hydrocarbons should enable more effective exploitation of the remaining resources worldwide, improving current recovery factors for oil (35%) and gas (60%).

At the exploration stage the key elements of source and reservoir rock distribution, trap configuration and integrity and hydrocarbon presence and distribution need to be imaged more comprehensively. For development planning the emphasis is on reservoir geometry that will impact expenditure through the number and placement of wells required to produce the field. During the production phase the monitoring of reservoir fluid movement is essential for production optimisation.

To address these issues reservoir imaging techniques need to improve substantially. The challenge over the next ten years is to economically monitor in real-time and under all overburden conditions, the distribution of oil and gas, constraining the reservoir geometry at the field scale through at least 50% improvement in current vertical and horizontal resolution.

The prize available through improved reservoir imaging is enticing, with the key being less expensive, faster more accurate understanding of rock properties and reservoir geometries. Although seismic technology has been the industry convention since the 1960s the scientific fundamentals are likely to prevent it achieving the targets set in this report.

However, the biggest challenge will be adoption by a conservative industry leading ITI Energy to focus on technologies which can be implemented within current workflows. In order to successfully create game-changing technologies the investigation of non-seismic/novel seismic techniques will be required. Although, the opportunities associated with alternatives/complements to seismic should be considered in relation to their technological maturity, cost and technical limitations.

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INTRODUCTION

This report attempts to define the commercial opportunities that improved reservoir imaging (RI) could access either through fewer dry holes or by improved assessment and recovery of reserves. This report builds on the findings of ITI Energy's Mature Oil & Gas Assets (MOGA) Foresighting exercise conducted in 2004, where "improved reservoir imaging" was identified as a prime target area for technology investment. The oil industry spends $7 billion/yr on geophysical acquisition and processing, this is set to increase as the focus moves to de-risking before drilling with the change to deepwater and small shallow water targets. The report should provide ITI Energy with the means to assess the attractiveness of RI technology investment and, by defining the opportunities, allow comparison with investment opportunities elsewhere in the energy sector.

This study investigates two aspects of the improved reservoir imaging target area – the potential opportunities that might be accessed and, through industry engagement, it tries to illustrate the specific challenges that need to be overcome and the principal reservoir imaging technical challenges currently faced.

The study was conducted in two phases:

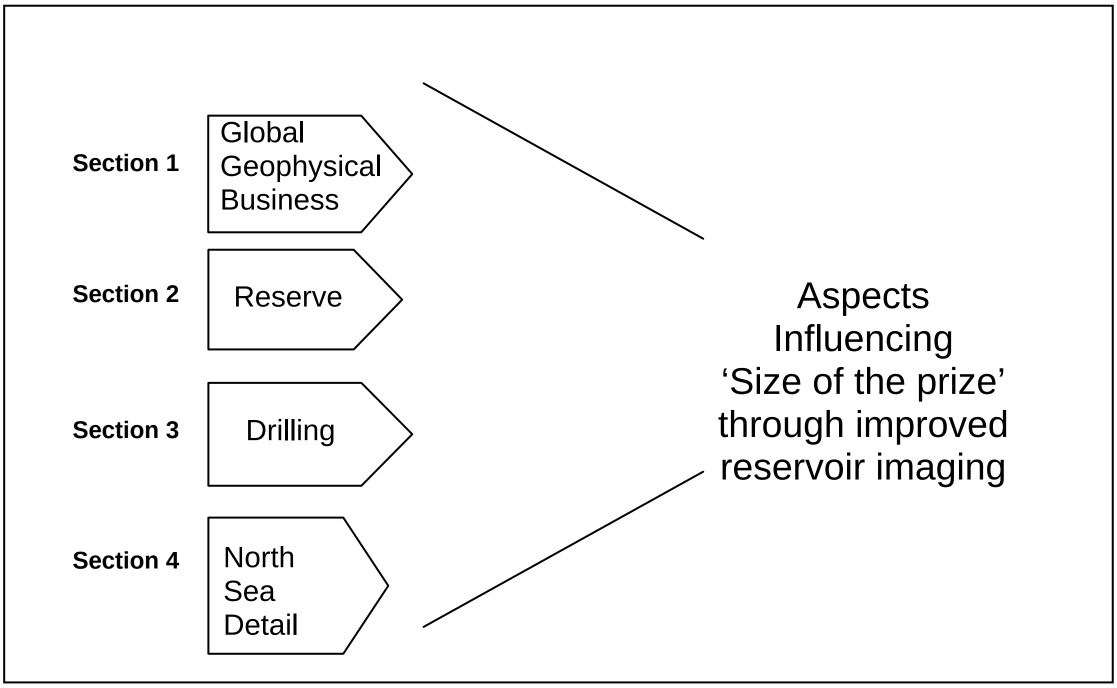
Phase I provided a framework for the assessment of the potential commercial opportunities that would result from improved reservoir imaging.

Firstly, the hydrocarbon volumes that improved imaging capability might find and develop more effectively and the distribution of the undeveloped/undiscovered hydrocarbon resource volumes was made by geographic region and geologic criteria. Characterisation of these lithologies and the reservoir architectures that certain depositional environments create allows target imaging criteria to be set.

Secondly, the cost-savings that can be made by better targeting of exploration and development wells through improved reservoir imaging was identified through an estimate of dry-well costs. This was defined globally and then more specifically for the North Sea region. Improved imaging of overburden conditions, trap integrity, reservoir distribution and direct hydrocarbon indicators will contribute significantly to reducing the current 70% exploration well failure rate.

Phase II focused on direct input from oil industry geophysicists, geologists, exploration managers and related academics on the specific reservoir imaging technical challenges that are currently being faced primarily in the UKCS but also elsewhere.

The study concludes with a summary of the main technical challenges facing the industry over the E&P lifecycle and a view of how the industry operating in the UKCS weighs their relative value.



1. GLOBAL GEOPHYSICAL BUSINESS

An understanding of the size of the market for existing Reservoir Imaging techniques is provided to help reinforce the estimates for current industry size and also highlights some of the limitations faced by oil companies using these techniques in 2005. As in other areas of the oil industry there is a significant period between proving the technology and the emergence of a sizeable market for the technology. Although marine 3D seismic was effectively a proven technique in 1980s it took around 15 years to grow into a >US$1 billion business.

Seismic imaging is the basis of a global $7 billion dollar industry, of this processing is ~US$1.5 billion and acquisition represents US$5.5 billion. More specifically 2D seismic surveys range from $500/km in a simple marine setting to $20,000/km in a complex land setting and 3D seismic surveys in similar environments commanding $15,000 to $80,000/km^2 (Fig.1) .

Fig 1: Global Seismic Industry Size and Costs

Seismic industry size

US$4.5 billion

Source: Robert Brunck Seismic and sustainable resource development The Leading Edge 2005 24: 180-181

Canadian seismic industry revenues ~$2 billion of which acquisition 20-25% i.e. $500 million/annum.

Source: M.Doyle Canadian Association of Geophysical Contractors (2003)

Survey Costs

$/km 2D $/km^2 3	2D		3D	
	Min	Max	Min	Max
Onshore	2000	20000	6000	80000
Offshore	500	1500	7000	25000

Source: www.indiainfoline.com (2002 data)

3D $/km^2	Acquisition	Processing	Total
Simple marine	10000	5000	15000
Complex land	40000	15000	55000

Source: Jahn, F., Cook, M. & Graham, M. 2001, Hydrocarbon Exploration and Production, Elsevier.

In 2003 some 160 geophysical survey crews were active outside the US. This level of activity has subsequently increased with 203 crews active in 2005. 530,000km of 2D and 80,000km^2 of 3D were shot. Of the 3D total, 125,000km^2 were offshore (Fig.2).

Fig 2: Non - US Seismic Activity

Geophysical Surveys		
Crews	2003	2004
Africa	28	26
Canada	12	15
CIS	31	19
Europe	16	10
Far East*	46	45
Middle East	15	21
Latin America	12	16
Totals**	160	152

* Includes China
** Excl. US
Source: IHS Energy Group

Seismic Crews		
	2004	**2005**
Africa	24	30
Canada	8	7
CIS	5	19
Europe	7	9
Far East*	44	47
Middle East	12	18
Latin America	13	21
United States	44	52
Totals	157	203

* Includes China
Source: World Oil Info June 2005/IHS Energy Group

Seismic Acquisition	2003		
	Total	Onshore	Offshore
3D Mkm2	180	55	125
2D Mkm	530		

Source: IHS Energy Group

Fig 3: Development of Seismic Technology

In complex environments the offshore industry has shifted from 2D towards the use of 3D seismic, or more recently, consecutive 3D seismic known as 4D, (eg. Valhal). The offshore seismic industry has a turnover of US$7 billion/year with 4D set to grow once equipment costs make the technique more accessible.

The use of ocean bottom cables (eg. Valhal as part of its Life of Field Seismic Project) has been a relatively recent change from towing seismic arrays enabling the utilisation of 4C seismic (multi-component including compressional waves (p-wave) and shear wave (s-waves)). The inclusion of shear waves (which would otherwise be absorbed by the water column) has successfully exposed additional resources such as the high porosity sands on the Alba field which were previously not seen on p-wave. Having enhanced seismic resolution in this way, oil company experience suggests that current resolution is an order of magnitude as accurate as achieved in drilling: typically 10m vertically, 40-60m horizontally and this depreciates massively with the complexity of the geological conditions.

With ocean bottom cables installed, the concept of repeating 3D seismic surveys more frequently becomes more realistic. So much so that BP initially proposed a schedule for Valhal of 6 surveys in 18 months (once every 4 months). This has subsequently been modified to once every 6 months based on the turnaround time of seismic processing (McBarnett 2004). However issues also exist in deriving most benefit from the data as business processes and decisions currently take too long to take advantage from the additional information.

The Delphi Consortium Seismic Research Programme (Berkhout, 2005), which is supported by the majority of the major oil companies, identifies specific strategic issues or challenges in acquisition, structural interpretation and reservoir characterisation which in summary include:

1. Seismic Data Acquisition Design: How to design economical acquisition geometries that will yield the best images in terms of spatial resolution and amplitude accuracy.

2. Structural Imaging: Removal of multiple scattering events through estimation of accurate migration velocity models e.g. imaging below salt is a largely unsolved problem.

3. Reservoir Characterisation: High resolution seismic images and accurate velocity models are needed to determine the volumetric properties of a field. The challenge is to move to more effective geologic parameterisation.

Moving away from the seismic process, Controlled Source Electromagnetics (CSEM) has recently emerged as a direct hydrocarbon indicator (Christie & Robein, 2005). The method depends on the resistivity contrast between a highly-resistive, possibly hydrocarbon-saturated reservoir rock, embedded in conductive shale, and its conductive water-saturated counterpart.

As yet there are still a number of issues to be addressed: reliable depth interpretation of the resistivity anomalies; optimal survey design; the need to record in a 3D sense both radial and transverse electric field components from both inline and crossline orientations of the horizontal electric dipole source; the use of CSEM in shallow water where the screening effect of the overlying conductive water layer is reduced, allowing coupling of the source and detectors through the resistive atmosphere; its application to time-lapse monitoring. CSEM has better resolution than potential-field methods but not the imaging capability of seismic methods. A rule of thumb would seem to be that a resistive target needs to have a diameter greater than its depth of burial before it can be mapped by CSEM methods (Constable, 2005).

Despite these issues CSEM has seen considerable success in the deepwater industry over the last 12 months. In late 2004, Morgan Stanley Equity Research, North America, predicted that CSEM operations could leap from a \$30 million to \$600-900 million business by 2010 – equating to about 25% of current spending on offshore seismic. The report also credited CSEM with contributing to ExxonMobil's remarkable run of 13 out of 13 successful deepwater exploration wells offshore Angola. However cost of EM is currently prohibitive for widespread use, outside high cost operating environment such as deepwater.

Potential-field methods are being developed to complement seismic data in velocity model building in areas of complex overburden (salt, basalt, tectonics) and in the prediction of reservoir rocks or fluids. Gravity-gradiometry is one such method which measures the gradient of the gravity vector in 3 dimensions. This provides a higher spatial resolution than gradients derived from measurements of gravity. Ultra sensitive potential-field sensors are used which only recently were de-classified by the defence industry (Smit et al, 2005).

Gravity gradiometry surveys run in 2002 in the Faroe/ West of Shetland region proved successful in imaging sub basalt to depths of 1500m (typically Lower Palaeocene) however of the 2-3 surveys run in the last year in the North Sea the process is best suited to shallow water depths (200-300m) to give resolution of low density sands and detection of structures several km wide. With resolution at this level the process is very much a frontier exploration tool only. Development of its airborne equivalent systems could enhance the potential for marine applications. Typically costs associated with gravity surveys are a fraction of those associated with CSEM or seismic techniques.

However all potential field techniques currently provide 'non-unique' responses therefore maximum benefit might be achieved where seismic and non-seismic can be cross-correlated to provide more information.

2. GLOBAL REMAINING RESERVES & UNDISCOVERED RESOURCES

To understand the potential prize of improved reservoir imaging this section estimates the scale of as yet undeveloped/undiscovered global and regional resource volumes. It draws upon a number of publicly available sources to develop a framework for reserves that could be exploited with the necessary improvements in reservoir imaging, defining the future market.

The USGS (United States Geological Survey) World Petroleum Assessment 2000 concluded that remaining reserves of oil, gas and NGL were 1.7 trillion boe (barrels of oil equivalent), conventional reserves growth would add another 1.3 trillion boe with 1.8 trillion boe of conventional resources still undiscovered (Fig.4).

Fig 4: Worldwide summary of estimates for undiscovered conventional resources and reserves growth for oil, gas and NGL

	Oil	Gas	NGL	
	MMMbbls	MMMboe	MMMbbls	
	Mean	Mean	Mean	
World (excluding United States)				
Undiscovered conventional	649	778	207	
Reserve growth (conventional)	612	551	42	
Remaining reserves	859	770	68	
Cumulative production	539	150	7	
Total	**2659**	**2249**	**324**	
United States				
Undiscovered conventional	83	88	Incl. in oil	
Reserve growth (conventional)	76	59	Incl. in oil	
Remaining reserves	32	29	Incl. in oil	
Cumulative production	171	142	Incl. in oil	
Total	**362**	**318**		
World Total (Including United States)	**3021**	**2567**	**324**	
Undiscovered conventional	732	866	207	**1805**
Reserve growth (conventional)	688	610	42	**1340**
Remaining reserves	891	799	68	**1758**

Source: USGS World Petroleum Assessment 2000

If worldwide oil demand levels continue to rise inline with the IEA forecast from 75 million bbl/day (in 2003) to 119 bbl/day by 2020 then production levels must increase from 26 billion bbl/yr (in 2003) to in excess of 43 billion bbl/yr (total of 520 billion bbl over this period). At the current discovery rate around 10 billion bbl/yr this leaves a deficit of 16 billion bbl/yr that needs to be discovered to replace produced reserves.

Addressing this shortfall means significantly reducing the risk associated with exploiting undiscovered resources. This is only likely to come as a result of continuing innovations in technology combined with access to areas where challenging conditions exist - such as areas that are presently inaccessible due to political circumstances or deepwater regions; where 65% of all discoveries in the last decade have occurred in water depths greater than 1000m (IHS Energy, Petroleum Trends (1994-2003).

However, improvements in geophysics could increase the longevity of politically stable region such as the UK by de-risking stratigraphic targets (e.g. Buzzard) and small accumulations/field rejuvenation.

The consequences of exploiting reserves in deepwater regions and the associated increased exploration and development costs mean the amount of investment in de-risking and the size of the reserves must be substantially increased to make each development economically viable. Technologies needed to explore and scope hydrocarbons in ultra-deepwater include, in Gulf of Mexico (GoM), sub-salt imaging and regional structural and stratigraphic mapping beneath the salt canopy. Current pre-stack depth migration requires a "window" through the salt to calibrate the seismic ray-paths received through salt - (Lamont-Doherty Energy and the Environment Group).

Exploitation of deepwater regions also presents resolution challenges due to absorption effects associated with increasing water column. The remoteness of the seabed means that imaging units (whether seismic, gravity or electro magnetic based) must be able to distinguish the signal above the noise attributed to the increased water column. Alternatively the units could be located on the seabed – which in itself presents hardware installation, communication, maintenance and repair issues/opportunities.

In addition to the effects of the water column, in the GoM for example, much of the ultra-deepwater (below 10,000ft) subsurface is obscured by the vast, horizontal, Sigsbee salt canopy (an amalgam of intermixed salt extrusion events) covering 45% of the surface area of the ultra deep. This terrain is similar to a lunar surface, and imaging beneath it will be a supreme challenge.

This example demonstrates how improved reservoir imaging could assist in the exploitation of significant undiscovered resources where risk and costs are high. Whilst it is difficult to predict exactly what proportion of undiscovered resource volumes worldwide will be unlocked by improved reservoir imaging, just 5% of the conventional reserves growth and conventional undiscovered resource volumes (3.1 trillion boe) represents around 160 billion boe.

3. GLOBAL DRILLING ACTIVITY

Global drilling in 2003, including all exploration, appraisal and development wells, totalled around 75,000 wells (World Oil & API 2005). In the US 30,741 of these were drilled and 12% were dry holes; the remaining 44,056 wells drilled outside the US at least 4% were found to be dry holes (Fig.5). This suggests an average of 7% of all wells drilled worldwide will be dry; this number is likely be higher as drilling is not always accurately reported by private or national oil companies.

By considering the costs associated with drilling each type of well it is possible to determine the 'loss' in the industry which could be potentially avoided with improved reservoir imaging.

Fig 5: Wells drilled worldwide in 2003

Wells Drilled (excl.US)		2003				
		Total	Oil	Gas	Dry	Susp
North America (excl US)		20576	4628	14384	1326	24
South America		2853	2236	99	91	146
Western Europe		594	151	68	45	13
	UK	266		na		
Eastern Europe/FSU		5542	3920	406	32	10
	Russia	4505	3740	333	na	
Africa		1059	729	104	110	76
Middle East		1501	756	94	42	34
	Saudi Arabia	330		na		
	Syria	103		na		
Far East		11737	1202	303	172	73
	China	9825		na		
South Pacific		194	73	40	78	2
Total (excl. US)		**44056**	**13695**	**15498**	**1896**	**378**

Wells Drilled (US only)	2003				
	Total	Oil	Gas	Dry	%Dry
No. of wells	30741	7968	19205	3568	11.6%
Cost $MM	127461	8265	111828	7368	
Av cost per well $MM	1.20	1.04	1.11	2.07	

Wells Drilled (Total)	2003				
	Total	Oil	Gas	Dry	%Dry
International (Outside of the US)	44056	13695	15498	1896	
United States	30741	7968	19205	3568	11.6%
Total	74797	Data incomplete			

Sources: World Oil Sept 2004, Feb 2005, API 2005

N.B. Best estimate of worldwide drilling in 2003, data incomplete at source

3.1 Exploration Wells

Worldwide figures (less China, the CIS and the US) suggest that 1869 international exploration wells were drilled in 2003 which increased to 2019 in 2004 (IHS Energy, 2005) with above average increases in Africa, Australia, the Far East and the Middle East but falling activity levels in Europe and the North American Frontier. Of this, about 1100 or 59% of the exploration wells drilled in 2003 were new field wildcats (Fig.6). This supports the increasing significance of new deepwater plays in areas such as West Africa and Australia seen in the exploration programmes of the super majors.

Deepwater exploration and development creates a market where derisking becomes more important and therefore the emphasis on remote sensing is greater, justifying increased expenditure. Novel Electromagnetic techniques (~US$1 million/survey) are only justified currently in deepwater where well costs exceed US$25 million. It is more challenging to make the business case for EM as well costs decline in shallow water.

Fig 6: Exploration wells drilled worldwide in 2003

International Exploratory Wells	2003	2004
Africa	296	357
Australasia	160	208
Europe	246	242
Far East	396	442
Latin America	486	472
Middle East	125	167
N. Am. Frontier	160	131
Total	1869	2019

Source: IHS Energy (Data from graphs)
NB: China and CIS excluded

Exploration Success Rate	General	WoS	DW
Source: IHS Energy-BP	33%		
Source: DTI WoS		20%	
DeepWater Discoveries			2.0%
DeepWater Econ.Discoveries			1.3%

Source: IHS Energy - BP 2005

World-wide Exploration Costs	2003
41 IOCs US$Bln	19
No. of International New Field Wildcats	1100
Cost per well US$MM	17.3
Cost of failed Expl. Wells US$Bln	12.7

Source: IHS 2005

Despite this shift the success rate in deepwater plays worldwide might be as low as the BP suggested rate of 2% (IHS Energy-BP, 2005) against an overall success rate worldwide of 33%. Applying these figures to the total worldwide exploration programme (less China, USA and the CIS) suggests that 1234 exploration wells drilled could prove to be dry.

Exploration well costs worldwide average $10-15 million/well (Bartling, 2005) and at the bottom end of that range with the data reported above, dry-hole costs would be close to $13 billion for exploration wells worldwide (less China, USA and the CIS).

3.2 Development Wells

Owing to the number of development wells on an international scale (typ: 42,187) dry-hole statistics are very much incomplete but a minimum figure that assumes a 6.5% failure rate and an average $2.1million/well would see a worldwide cost for development wells close to $6 billion (Fig. 7)

Fig 7: Worldwide dry well costs

Case I					
Dry holes world-wide		**Wells**	**Dry**	**Cost/Well**	**Total $MM**
Int'l New Field Wildcats	Assume 80% failure rate	1100	880	17.3	15200
Int'l Development	Assume 11.6% failure rate and US costs	42956	4983	2.1	10290
US Wells		30741	3568	2.1	7368
Totals		74797	9431		**32858**
	Dry Wells Cost $32.9 Bln				

Case II					
Dry holes world-wide		**Wells**	**Dry**	**Cost/Well**	**Total $MM**
Int'l Exploratory Wells	Assume 67% failure rate	1869	1252	10.2	12730
Int'l Development	Assume 6.5% failure rate and US costs	42187	2743	2.1	5665
US Wells		30741	3568	2.1	7368
Totals		74797	7564		**25763**
	Dry Wells Cost $25.8 Bln				

Dry Wells Cost Range US$ 26-33 Billion

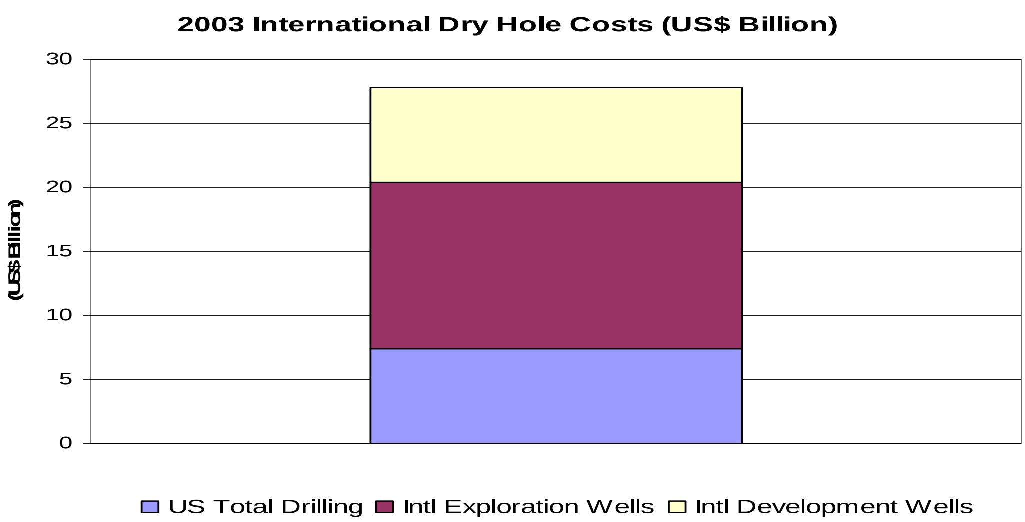
3.3 Overall Dry-Hole Costs

Dry-hole costs (exploration and development) are officially reported in the US, and in 2003 this averaged $2.1million/well, giving a US total of $7.4 billion. This added to the separate costs above for exploration ($13 billion) and development ($6 billion) dry wells outside of US would give a minimum figure of $26 billion for worldwide dry-hole costs (Fig.8).

Considering these costs as an annual worldwide ‘loss’, and assuming that most wells prove to be dry as a result of a poor understanding of the geology (as opposed to inaccurate drilling), then it is possible to see the significant role that improved reservoir imaging could play in reducing this $26 billion annual ‘loss’.

To make savings of this magnitude and with worldwide application, it provides a significant incentive to address the current limitations of reservoir imaging as it stands today.

Fig 8: 2003 International Dry Hole cost



4. NORTH SEA UNDISCOVERED RESOURCES

The study has focused on the North Sea to gain and extract specific issues surrounding reservoir imaging that might help to unlock the world's remaining undiscovered resources (1.8 trillion boe) and to reduce the $26 billion 'loss' associated with worldwide dry well costs as described in the previous sections. In addition, the North Sea represents one of the most politically and economically stable locations to explore and produce hydrocarbons.

Government statistics suggest that there are some 17 billion bbls of oil and 3 trillion m3 gas (totalling 35 billion boe) still to be discovered in the North Sea (Fig.9) – around 2% of the world's undiscovered reserves.

The Norwegian Sector is seen to be the most prospective with estimates of 9.4 billion bbls of oil and 1.9 trillion cu.m gas – total 20.8 billion boe (NPD Resource Book 2005).

The UK Sector may yield expectation volumes of undiscovered resources of 6.4 billion bbls oil and 512 billion cu.m gas – a total of 9.5 billion boe (DTI, 2005).

Exploration potential in the Danish Sector is put at 1.3 billion bbls oil and 152 billion cu.m gas – total 2.2 billion boe (DEA, 2004). In the Netherlands there is an expectation that some 385 billion cu.m gas (2.31 billion boe) may yet be found (TNO-NITG, 2003).

This not only highlights the potential of the Norwegian sector but also the significance of gas reserves (over 50%) across the region. With recovery rates typically 35-37% for oil and 50-60% for gas (Schlumberger 2004) it is likely that only about 16 billion boe will be produced from the North Sea. Realising the remaining value from the already mature North Sea sector necessitates developments in terms of Enhanced Oil Recovery (EOR) and Rejuvenation. Consequently improved reservoir imaging has a significant role to play not only in exploration and development drilling but also in EOR and Rejuvenation activities.

Fig 9: North Sea Undiscovered Resources

UK North Sea	Undiscovered Resources					
	Oil (MMbbls)			Gas (MMMm^3)		
	L	M	H	L	M	H
Northern North Sea	278	578	1005	9	18	36
Central North Sea	2370	3585	5753	133	201	332
Southern North Sea/Irish Sea/Celtic Basin	0	0	83	96	145	300
West of Shetland	315	1283	3540	41	104	365
West of Scotland	0	900	3000	14	42	198
Land	8	68	203	0	2	6
Other areas	0	0	143	0	0	8
Totals	**2970**	**6413**	**13725**	**293**	**512**	**1245**

Source: www.og.dti.gov.uk/information (2005) data as of end 2004

PILOT UK Brownfield Study (March 2005)	Exploration Yet-to-Find
	8.9 MMM boe

Norway	Undiscovered Resources					
	Oil (MMbbls)			Gas (MMMm^3)		
	L	M	H	L	M	H
North Sea		4340			500	
Norwegian sea		2579			810	
Barents Sea		2516			590	
Totals		**9435**			**1900**	

Source: NPD Resource Book 2005

Denmark	Undiscovered Resources					
	Oil (MMbbls)			Gas (MMMm^3)		
	L	M	H	L	M	H
Producing Fields						
Other Fields						
Discoveries						
Exploration Potential		1289			152	
Totals		**1289**			**152**	

Source: DEA - Oil and Gas Production in Denmark 2004

Netherlands	Undiscovered Resources					
	Oil (MMbbls)			Gas (MMMm^3)		
	L	M	H	L	M	H
NL Territory				60	115	170
Continental Shelf				140	270	400
Totals				200	385	570

Source: TNO-NITG Oil and Gas in the Netherlands 2003

Estimated

Undiscovered Oil MMbbls		**17137**				
Undiscovered Gas MMMm^3					**2949**	

Total Undiscovered Resources		
	Oil	**17 billion barrels**
	Gas	**3 trillion m^3**

5. NORTH SEA DRILLING ACTIVITY

5.1 Exploration Wells

In the North Sea between 1995 and 2004, of the 726 exploration wells drilled, 466 (65%) were dry-holes. Using a cost per well of $10 million each (Bartling), gives a dry-hole cost of $5 billion for exploration wells over a 10 year period – an annual 'loss' of $466 million in the North Sea alone.

Success ratios were higher in the Dutch 50%, Norwegian 48% and Danish 33% sectors than in the UKCS 22%, this probably reflects the relative maturity of the UKCS (Fig.10). However the overall 35% success rate demonstrates the potential scope for improvement in terms of reservoir imaging across North Sea.

Fig 10: North Sea Exploration Well Success Rates

Total North Sea	1995-2000			2001-2003/4			1995-2003/4				
	Wells	Discoveries	SR	Wells	Discoveries	SR	No. Wells	Discoveries	SR	Dry Holes	DH%
UK	261	54	21%	86	21	24%	347	75	22%	272	78%
Norway (Wildcat)	126	55	44%	61	35	57%	187	90	48%	97	52%
Denmark	23	na	na	12	4	33%	12	4	33%	8	67%
Netherlands Territory	47	24	51%	10	4	40%	57	28	49%	29	51%
Netherlands CS	85	42	49%	38	21	55%	123	63	51%	60	49%
	542	**175**	**32%**	**207**	**85**	**41%**	**726**	**260**	**36%**	**466**	**64%**

NB: 1995-2003/4 well total excludes wells drilled 1995-2000 for which discovery data is not available
SR = Success Rate
DH= Dry Holes

Fig 11: UKCS Exploration Well Success Rates

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Av.
Southern North Sea	30%	17%	25%	33%	67%	33%	50%	67%	14%	25%	36%
Central North Sea	5%	10%	18%	13%	22%	0%	0%	14%	17%	14%	11%
Northern North Sea*	50%	55%	46%	38%		60%	100%	100%	100%	0%	61%
West of England/Wales	0%	0%	50%	0%					0%		10%
West of Shetland	0%	14%	0%	0%	50%	17%	0%	0%	0%	33%	11%
Channel/SW Approaches	0%	0%					0%				0%
Success Rate	11%	17%	25%	21%	50%	22%	30%	45%	26%	18%	22%
Period Success Rate	21%						24%				

Source: Based on DTI data on Offshore Exploration Wells Drilled (excl. sidetracks) and Significant Discoveries
NB: DTI Significant Discoveries data is probably not fully reflective of technical success rates

DTI data (Fig. 11) for the same period (1995-2004) suggests that the UKCS exploration well success rate ranged from 11% in the Central North Sea and West of Shetland (WoS) to 61% in the Northern North Sea.

For the UK Atlantic Margin (West of Shetland), comprising a large area of rifted basins associated with North Atlantic rifting during the Mesozoic and Palaeocene ages, it is reported that for the 147 exploration wells drilled since 1972 the success rate was 1 in 6 and only 33% of the wells were located on a robust, reliable structure (Loizou, 2004). Moreover, it is estimated that 67% of the wells that failed (16 in total at a cost of $240 million) did so because of the lack of a genuine trap. This is attributed to positioning based on poor quality 2D seismic data, combined with simultaneous or back-to-back exploration drilling, which did not allow for analysis to be completed nor traded between companies, after initial drilling. Although the WoS represents the long term future of the UK E&P industry, this potential cannot be realised until associated RI issues are overcome.

5.2 Development Wells

No summary data is available on development well success/failure rates. However 35% of UKCS development wells (824 out of 2385 wells between 1995 and 2004) were sidetracked to new targets seeking new geological data. It is not possible to conclude that the original wells failed to meet their objectives because of geological uncertainty, but it is likely is was a factor (Fig. 12)

Fig 12: UKCS Development Well Sidetrack Rates

Offshore Development	1995		1996		1997		1998		1999		2000		2001		2002		2003		2004			
	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S		
Southern North Sea	31	8	8	5	14	6	18	12	18	17	17	12	7	6	16	15	13	21	6	6		
Central North Sea	92	18	79	25	64	36	75	30	48	44	42	24	73	46	42	53	40	37	54	44		
Northern North sea	64	14	83	34	96	33	77	43	57	25	67	36	81	41	60	48	58	15	34	15		
West of England/Wales	11	2	12	2		1	2	1	5	3	5	3	6	10	7	3	6	3	1			
West of Shetland	4		11	2	5	2	17	1	10	3	3	7	9	3	2	3	8	3	3	3		
Channel/SW Approaches																						
Sub-totals	202	42	193	68	179	78	189	87	138	92	134	82	176	106	127	122	125	79	98	68	1561	824
Totals	244		261		257		276		230		216		282		249		204		166		2385	
% Sidetrack wells	17%		26%		30%		32%		40%		38%		38%		49%		39%		41%		35%	

Source: Modified after www.og.dti.gov.uk/information (Drilling Activity)

W – Well, S – Number of wells sidetracked

5.3 Overall dry-hole costs in UKCS

If we assume a 22% success rate for exploration wells at a cost of $10 million each well (272 dry out of 347 wells) and a 65% success rate for development wells at a cost of $2.1 million each well (824 sidetracked out of 2385 wells) over the same period (1995-2004) in the UKCS, then overall 'losses' total $4.5 billion for the period or $450 million per year.

This gives us an indication of the scale of the potential 'losses' that could be avoided in the UKCS alone, if improved reservoir imaging can provide better quality geological data to help more accurately position exploration and development drilling.

6. RESERVOIR IMAGING ISSUES

This section aims to pin down more precisely what the technical challenges are that prevent access to better quality geological data and to understand just how accurately we need to be able to position exploration and development drilling to increase the likelihood of targeting a genuine trap and other reservoir bearing units.

6.1 Global Perspective

Reservoir Imaging Issues versus Business Need

Kristiansen & Waggoner (2005) provide a comprehensive list of reservoir imaging issues which was originally compiled to assess the potential value of using multi-component seismic data (4C) to better characterise reservoirs. These and other imaging issues related to overburden, trap, seal and reservoir have been mapped subjectively to a number of generic E&P business needs.

These needs span the E&P lifecycle from exploration through appraisal and development to optimising production performance and eventually identifying by-passed oil and EOR targets (Fig.13).

Fig 13: Reservoir Imaging Needs by Business Need

Reservoir Imaging Issues	Business Needs				
	Increase Recoverable Reserves			Production Optimisation	
	Enable the quantification of oil and gas reserves under severe geological constraints	Reduce the number of dry or sub-economic wells drilled	Enable the development of marginal reserves	Optimise production rate for improved UR	Identify By-passed Oil
Overburden					
Signal/Noise					
Multiple prediction and attenuation					
Anisotropy in PSM velocity analysis					
Sub-basalt					
Sub-salt					
Sub-chalk					
Sub-dune					
Sub-gas cloud					
Deepwater gas hydrates					
Seal					
Shale					
Salt					
Trap					
XYZ determination (see also Anisotropy above)					
Extensional					
Compressional					
Stratigraphic					
Palaeogeomorphic					
Non-tectonic					
Structural-stratigraphic					
Reservoir Rock Properties					
Continental clastics					
Paralic clastics					
Shallow marine clastics					
Shallow marine carbonates					
Deep marine clastics					
Deep marine carbonates					
Basement (crystalline) reservoirs					
Porosity/Permeability prediction					
Fracture characterisation (size, orientation, intensity)					
Fault pattern and density					
Fluid filled cracks critical systems imaging					
Reservoir Fluid Properties					
GOW contacts					
Oil characteristics					
Gas characteristics					
Pore fluid saturation mapping					
Pore pressure prediction					
Reservoir fluid movements					
Reservoir microseismicity					
Data Management					
Mass data storage					
More data to process - less expertise					
Sorting of large volume datasets					
Scale or resolution relative to decision to be made					
The Integration Imperative					

As an asset is progressed through its lifecycle so are the demands asked of reservoir imaging to become more specific.

Exploration

During the exploration phase the emphasis is on imaging and predicting reservoir, trap, seal and charge often under complex overburden conditions.

Development

Overburden conditions such as basalt layers provide highly reflective top and base boundaries together with complex internal structures that make successful imaging difficult. The basalt layers typically create strong multiple reflections and severely attenuate and scatter seismic energy, thus hindering the transmission of seismic energy and making it difficult to distinguish the returning signal from background noise beneath basalts (Spitzer 2005).

Through the phase of appraisal and development decision-making, structural and stratigraphic complexity at the reservoir level must be addressed in the context of hydrocarbon distribution and the number and type of wells that might be required to drain the reservoir adequately. This must be achieved with an imaging resolution comparable to the size of key features such as the trap and the seal. The various types of trap, seal and reservoir rock provide different challenges in terms of imaging (some significantly more so than others) but are included for completion.

Enhanced Oil Recovery

Accurate well placement in the reservoir becomes a key factor in later field life as attempts are made to improve the ultimate recovery by specifically targeting small pools of by-passed oil or seeking to implement IOR/EOR projects. This poses challenges in terms of tracking reservoir and fluid properties as the field is developed. Assuming that larger, easier to access reserves are produced first implies that the target reserve size becomes increasingly smaller and more complex with each field development. Consequently imaging challenges are focused on resolution to enable successful detection of reservoir fluid changes with time.

Aside from this, throughout the field life cycle the use of ever increasing volumes of raw data creates a significant challenge in terms of handling, processing and interpretation times especially as the industry moves to a real time environment.

Reservoir Imaging Issues versus Undiscovered Resources

To try to understand the significance of each of these issues and the potential ‘size of the prize’ in addressing them, the USGS WPA 2000 database has been sourced to quantify issues related to seal, trap and reservoir rock properties. In as much as reservoir seal, trap and rock properties are fundamental to the accumulation and eventual production of hydrocarbons they are prime targets for improved imaging.

By considering the percentage distribution of undiscovered resources globally, shales are by far the dominant seal lithology. In terms of seismic imaging, substantial shale beds frequently exhibit anisotropy and consequently present velocity variations which pose additional processing issues. Through improved imaging it is possible reduce the structural risk associated with drilling in these lithologies.

Structural traps are expected to contain three times the hydrocarbon volume of stratigraphic traps and there is a sub-equal split of hydrocarbon volumes over four reservoir lithologies – shallow marine carbonates (high velocity structures with limited penetration of energy), deep marine clastics, shallow marine clastics and paralic clastics (Fig.14).

On this basis we have an indication of the potential global 'value' of each imaging issue in terms of the percentage of undiscovered resources.

Fig 14: Percentage Distribution of Undiscovered Resources by Seal, Trap and Reservoir Properties

Reservoir Imaging Issues	World Outside US	Former Soviet Union	Middle East & North Africa	Asia Pacific	Europe	North America (non-US)	Central & South America	Offshore West Africa	South Asia
	USGS World Energy Project 2000 Province data based on 26 Assessment Units with >5Bbbls Undiscovered Conventional Oil Resources and covering 70% of the estimated undiscovered oil outside of the US.								
	Undiscovered Conventional Oil Resources MMbbls								
	454088	72298	179276	5364	13616	64828	54666	64040	nd
Seal									
Shale	76%	79%	50%	100%	100%	100%	91%	100%	nd
Salt	24%	21%	50%				9%		
Trap									
Extensional	30%		18%		73%	73%	10%	34%	nd
Compressional	31%	34%	68%	33%	0%		14%		
Stratigraphic	19%	35%	5%	33%	27%		31%	62%	
Palaeogeomorphic	4%	21%	5%	33%					
Non-tectonic	9%	10%	4%				21%	4%	
Structural-stratigraphic	7%					27%	23%		
Reservoir Rock Properties									
Continental clastics	7%	10%	11%	0%	14%		5%		nd
Paralic clastics	17%		24%	50%	36%		5%	34%	
Shallow marine clastics	20%	30%	9%	0%	36%	73%	5%		
Shallow marine carbonates	27%	21%	56%	50%	0%		13%		
Deep marine clastics	25%	39%			14%		73%	66%	
Deep marine carbonates	4%					27%			

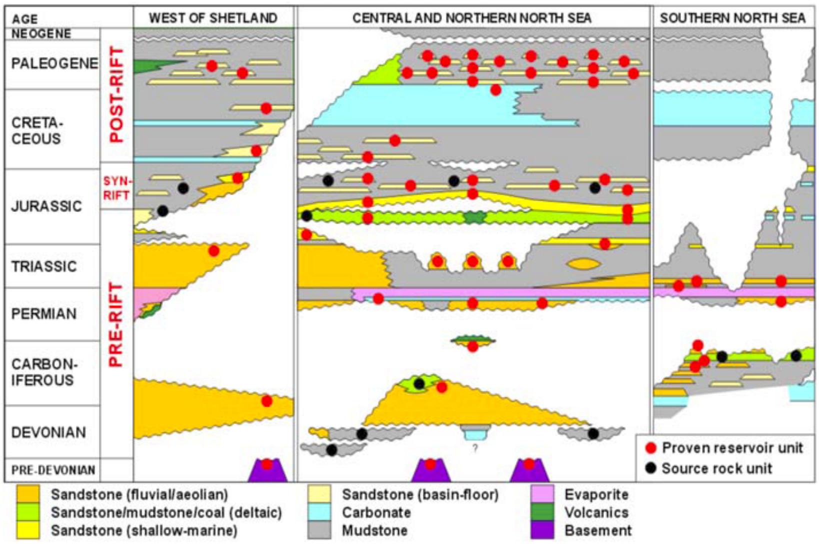
6.2 UKCS Perspective

Fig. 14 suggests that the distribution of undiscovered resources in Europe is not dissimilar to the pattern seen in North America. One exception to this is the significance of the basalt layer in the West of Shetland – which is more significant in the North Sea. However in order to identify the specific challenges associated with each issue listed above we have focused on experiences and resources in the UKCS.

Stratigraphic Distribution of UKCS Undiscovered Resources

The distribution of reserves in a stratigraphic column taken through central and northern north sea (CNS, NNS) oil provinces, the southern north sea (SNS) gas province) and West of Shetland is shown in fig. 15.

Fig 15: UKCS Existing Reserves by Stratigraphic Column



Based on the assumption that the distribution of undiscovered resources across the various plays are likely to be in the same proportions as remaining reserves it is estimated that some 56% or 5 billion boe of undiscovered resources in the UKCS will be found in the shallower syn-rift Upper Jurassic and post-rift Lower Cretaceous and Palaeogene deepwater sandstone reservoirs (Modified after Munns et al, 2005, Table 3). It is believed that new exploration plays could be found in Palaeogene sandstone injectites which as yet have proven difficult to image due to their angle and the limitation of vertical resolution.

In fields and discoveries to end 2003, stratigraphic trapping mechanisms occur in sections closely associated with deep-water sandstone plays, however, only 17% of the discovered reserves occur within stratigraphic or combination traps – the Buzzard oil field is a spectacular example. Considering the play facies, and play maturity, it is perceived that there are many more stratigraphic traps out there, perhaps making up 50% of the total UKCS undiscovered resources (BGS, DTI 2004). The current limitations of imaging make it difficult to identify and delineate these traps due to the scale at which they exist; typically 60ft.

Another 2.4 billion boe may be housed in pre-rift Carboniferous, Permian and Upper Triassic/Lower Jurassic sandstones deposited primarily in continental fluvio-deltaic, aeolian and alluvial settings. A poor impedance contrast at the target level makes it difficult to gain adequate resolution in the Carboniferous and remains an imaging challenge.

Middle and Upper Jurassic shallow marine/deltaic sandstones and Palaeogene deltaic sandstones may contain a further 1.2 billion boe. Permian and Upper Cretaceous carbonates with an estimated 0.6 billion boe complete the picture (Fig.16). Previously carbonates (such as chalk) have been uneconomic to exploit owing to the difficulty in imaging the chalk due to its associated seismic velocity variations which provide imaging issues similar to basalt (Amerada Hess).

Fig 16: UKCS Undiscovered Reserves by Lithology and Depositional Environment

Based on an Undiscovered Resource Volume of 9.5 MMMBOE

Play Group		Lithology/Depositional Environment						
		Sst	Carb	DW	SM/D	Aeolian	Fluvial	Basement
		Figures in MMBOE						
Post-rift	Pliocene sandstones							
	Palaeogene deltaic sandstones				190			
	Palaeogene deepwater sandstones			2090				
	Upper Cretaceous carbonates		475					
	Lower Cretaceous deepwater sandstones			1140				
Syn-rift	Upper Jurassic deepwater sandstones			2090				
	Upper Jurassic shallow-marine/deltaic sandstones				760			
Pre-rift	Middle Jurassic shallow marine/deltaic sandstones				285			
	Upper Triassic to Lower Jurassic sandstones	760						
	Lower Triassic fluvial sandstones						95	
	Permian aeolian sandstones					665		
	Permian carbonates		95					
	Carboniferous sandstones	760						
	Devonian sandstones	95						
	Basement							
	Total	1615	570	5320	1235	665	95	0
		17%	6%	56%	13%	7%	1%	0%

Source: Modified after Munns et al. 2005

Undiscovered resources	
Pre-rift Sandstones	25% 2.4 MMMBOE
Deepwater Sandstones	56% 5.3 MMMBOE
Shallow Marine/Deltaic Sandstones	13% 1.2 MMMBOE
Carbonates	6% 0.6 MMMBOE

The main focus in terms of reservoir imaging is the definition of the various architectures (shapes and stacking patterns e.g. fan-like, lobate, lens-like, long thin channels) associated with each of these groups. Given that the size and distribution of these architectures varies between groups, the study sought to consult industry representatives to determine which features and architectures posed most challenges to them in terms of reservoir imaging.

Reservoir Imaging Issues by Operator

Ten operators with a primarily North Sea focus with activities covering the E&P lifecycle as described in the previous section and one academic with strong connections to the industry were interviewed to identify the highest priority issues with regard to the specific reservoir imaging challenges that impact their exploration and field development activities (Fig. 17).

Operators were targeted with good track records in the use of leading edge imaging technology as evidenced by their recent publications in the geophysical journal First Break and in the proceedings of the 6th Petroleum Geology Conference, London, 2003: In: Doré, A.G. & Vining, B.A. (eds) Petroleum Geology of North-West Europe and Global Perspectives, 2005.

In order to prioritise and evaluate the preliminary list of issues (as sourced in the previous section) operators were asked what it is that cannot currently be done in the field of reservoir imaging that if solved would enable step changes to happen in E&P performance across the lifecycle.

The technical challenges that were derived from the interviews were grouped according to technical area and then merged with the existing list in accordance with the three main stages of the E&P lifecycle.

Fig 17: Reservoir Imaging Issues by Oil Company

Reservoir Imaging Issues vs. Business Needs (Final List)					
Reservoir Imaging Issues	E&P Lifecycle: Exploration	E&P Lifecycle: Development	E&P Lifecycle: EOR/Field Rejuvination	Operators	Univ.
Seismic Data Acquisition & Processing					
Data acquistion					
Reduce OBC costs by 90%					
Reduce OBC costs by 50-80%					
Full electric field 12.5m spacing over 150km2					
4D on demand - real-time permanent sampling					
4D - Higher resolution of the delta between surveys					
4D in tight reservoirs with <20% porosity					
Amplitude and Bandwidth					
Preservation of (true) amplitude and bandwidth					
Retention of low frequencies (down to 5Hz)					
Water column absorption					
Repeatability of c-wave data					
Multiple prediction and attenuation					
Multiple-free data					
3D solution to point source multiples					
Lateral velocity models at scale of 10-100m					
Signal:Noise					
Make use of more than 1% of the seismic data					
Overburden					
Sub-dune (North Africa)					
Shallow, buried channels					
Shallow section <60°C under-explored					
Sub-basalt - no frequencies above 30-40Hz					
Gas clouds - TZ conversion pull downs					
Chalk - Velocity variation 2500-4000m/s					
Sub-chalk - Angle limitation below high velocity layers					
Need 40-45Hz for AVO					
Trap					
XYZ resolution					
5m in Z (Drilling equivalent accuracy at target position)					
20-30m in XY (Drilling equivalent accuracy at target position)					
[Forties] Require 70-80Hz for 15-20m resolution					
[Chalk] Migration uncertainty 200m in XY					
[Chalk] Seismic inversion (2m claimed but 10m more likely)					
[SNS Carb] Need 10m resolution in Z at 3000-4000m					
[General] Require 70Hz under poor overburden conditions					
Stratigraphic Traps					
Palaeogeomorphic Traps					
Structurally Complex Compartmentalised Traps(dipping/faulted)					
Unconventional traps					
Injectites					
Imaging steep limbs 35°					
Reservoir Rock Properties					
Chalk					
Low permeability					
High porosity					
Subsidence					
Permeability					
Permeability prediction					
Understand and exploit heterogeneity					
Low permeability reservoirs					
Pay identification and distribution in poor quality reservoirs					
Forward modelling rock properties to logs to seismic					
Fracture characterisation (size, orientation, intensity)					
Basement (crystalline) reservoirs					
Reservoir Fluid Properties					
Heavy oil at shallow depths					
Pore fluid saturation mapping					
Reservoir fluid movements					
Definition of fluids					
Work Processes					
Shorten processing time					
Shared Earth Model - the integration imperative					
Work flow and the human interface					

(Black – high-level issue, Red – specific target)

6.3 Prioritisation of Technical Challenges

By considering the technical challenges against the weight of industry concern and the potential value of addressing each issue, the following challenges have been identified of most significance to the UKCS industry at the various stages of the field development life cycle.

Stage	Key Challenges	Resources Value	Drilling Value
Exploration	Visibility under all overburden conditions	Applicable to all resources	Reduced structural risk, no drilling blind
Exploration & Development	Reservoir geometry and resolution of 15-20m (70-80Hz) below Cretaceous levels	Below cretaceous > 50% UKCS resources	
Development	Reduction of OBC data acquisition costs by 50% Real time delivery of 4-D seismic data	Production optimization Production optimization	Reduce no. dry wells Reduce no. dry wells
EOR & Rejuvenation	Definition of fluid properties with resolution of 20m XY, 5m Z	Production optimization	

The following points and comments were raised by the industry sighting examples of specific issues that relate to these five overriding challenges.

Exploration

Visibility under all overburden conditions

The bulk of the reservoir imaging undertaken in the search for hydrocarbons is based on seismic reflection data. Spatial variations in lithology and fluids in the overburden create reservoir imaging challenges. Of particular note for the companies interviewed were the challenges posed by near surface point source anomalies creating energy scattering, gas clouds overlying reservoirs, variable overburden velocities and high velocity layers such as the Chalk and in certain areas basalt.

Gas strongly absorbs P-waves which propagate through both the rock framework and the fluids within the pore space. As such there is an incomplete illumination of target reflectors below gas clouds when using traditional surface 2D or 3D seismic data. Velocity variations between 2500 and 4000m/s above the Chalk pose major challenges for migration algorithms and operators find themselves in a situation that is tantamount to drilling blind through gasclouds on the assumption that the gas cloud is situated above the reservoir.

Imaging below Chalk in the North Sea is compromised by loss of seismic energy at the base Chalk. One large operator described this as an angle limitation for successful imaging, stating that there was a minimum requirement for 40-45Hz below the Chalk in order to use AVO techniques.

The basalt layer found in the West of Shetland does not allow effective imaging through it due to the poor return of seismic energy caused by high impedance contrast at the top of the basalt, scattering induced by the rugosity of basalt surfaces and internal heterogeneities in the basalt which give more scattering and extensive intra-bed multiples (Maresh & White, 2005). This scattering gives rise to the loss of high frequency components > 30-40Hz. The energy returned is strong in low frequencies but poor in high frequencies.

Given that some wells are already being drilled blind through overburden conditions it appears that the prize for addressing this challenge is about reducing the risk as opposed to accessing additional reserves. The ability to successful image under (through) all overburden conditions which may in part be addressed by long offset seismic (Jon Gluyas, Acorn Oil) or ocean bottom cabling in the case of development drilling (Gary Marsden, Amerada Hess) has significant potential in terms of increasing success rates in both exploratory and development drilling across the North Sea.

Sandstone injectites are a new exploration play in the Palaeogene of the North Sea. They are intrusive sand bodies occurring as dykes, sills and emergent sills (Hurst et al, 2005). In part they may be highly discordant (up to 35°) with the enveloping strata and pose a distinct imaging problem.

Reservoir geometry and resolution of 15-20m (70-80Hz) below Cretaceous levels

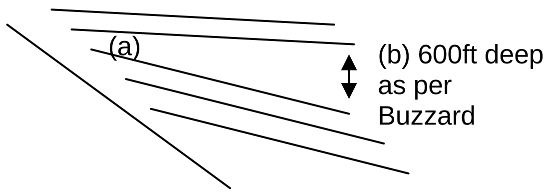
Vertical resolution at target depth is a key issue. Tertiary targets such as stacked turbidites in the Forties Formation in the North Sea can be relatively well imaged with seismic frequencies of 60-65Hz. Identifying individual sand units within those stacked sequences is problematic. Shell indicated that their target is to achieve 70-80Hz to provide a vertical resolution of 15-20m.

One operator suggested the need to double the frequency from 30 to 60Hz in order to see 10m resolution when they can only achieve 20-30m currently. This would allow them to map in more detail and exploit fractured carbonates (typically in shallow gas clouds – a major problem in Norway, Bohai Bay & China).

A vertical resolution of 15-20m is also the target set by most operators for the imaging of individual sand bodies in pre-Cretaceous deposits.

Another operator stated the requirement to increase frequencies of seismic data to detect contrasts such as ‘stratigraphic traps’ as shown in figure 18 at point (a).

Fig 18: Identification of Stratigraphic Trap; vertical resolution 60ft



Improved resolution to 15-20m below Cretaceous levels may be the single most significant imaging contributor to unlocking undiscovered resources in the North Sea. Resolution of this accuracy at say 3000m depth would enable targeted drilling of smaller reserves attributed to both stratigraphic and structural traps which otherwise may be bypassed and left undiscovered.

Development

Reduction of OBC data acquisition costs by 50%

Currently the factor preventing the widespread uptake of OBC data acquisition and life of field seismic is the cost of implementation. Only fields with extensive development drilling campaigns can justify these costs. Operators are seeking 50-90% cost reductions and would like to be able to put in place a 'full electric field' with 12.5 m spacing over a 12 x 12km field area with shear wave source on the seabed to take out multiples and water absorption (still a minor issue).

Real time delivery of 4-D seismic data

One operator suggested that better & faster processing capabilities were now available in terms of computing power which combined with increased manning and staffing levels in the service company sector should allow the development of faster delivery of data, and the ultimate goal of real time delivery of 3D/4D avoiding the typical 4-5 month bottlenecks that are currently experienced. Ideally oil companies would like to acquire data on demand to address field production problems.

Another suggested that shorter licensing periods highlight the need for faster processing times.

EOR & Rejuvenation

Definition of fluid properties with resolution of 20m XY, 5m Z

Given that EOR and rejuvenation targets are likely to be smaller than exploration or development targets, it is critical that individual reservoir flow units and their fluid distributions can be resolved to a similar level of accuracy as that which can be drilled. Typically this would mean 20m in XY and 5m in Z. The prize for field rejuvenation with this level of imaging resolution in the North Sea could be as much as 5 billion barrels.

7. CONCLUSION

This report has identified the significant commercial opportunities that improved reservoir imaging could take by reducing the number of dry holes and improving finding and exploitation of reserves. By example, world-wide dry-hole costs are estimated to be a minimum of $26 billion/year. Additionally, if improved imaging could increase the conventional reserves growth and undiscovered hydrocarbon volumes by 5% it would amount to around 160 billion boe.

Seismic, the conventional technique for reservoir imaging is a multi-billion dollar industry that has been the mainstay of the industry since the 1960s. Although seismic techniques are being developed to address the challenges outlined in this report, it could be argued that the fundamental science behind seismic will prevent success.

Solutions to a number of these challenges are imperative to reduce risk, particularly as the nature of E&P changes, with targets getting smaller and exploration and development moving into deeper water. In order for oil companies to make decisions to drill (invest), in either setting, risk must be sufficiently reduced. The limitations of seismic technology should encourage investigation of other technologies such as EM, gravity and others.

The biggest challenge will be adoption by a conservative industry therefore ITI Energy will focus on technologies which can be implemented into current workflows. To successfully create game-changing technologies the investigation of non-seismic/novel seismic techniques will be required. However, the opportunities of alternatives/complements to seismic should be considered in relation to their technological and commercial maturity, cost and technical limitations.

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APPENDIX 1 - DEFINITION OF TERMS

Source: Schlumberger Oilfield Glossary; http://www.glossary.oilfield.slb.com/

Alluvial	Sediments deposited in an alluvial environment can be subject to high depositional energy, such as fast-moving flood waters, and may be poorly sorted or chaotic.
AVO	(amplitude variations with offset): Seismic technique that uses pre-stack seismic data; indicates differences in lithology and fluid content in rocks. A limitation of AVO analysis using only P-energy is its failure to yield a unique solution, so AVO results are prone to misinterpretation. One common misinterpretation is the failure to distinguish a gas-filled reservoir from a reservoir having only partial gas saturation ("fizz water"). However, AVO analysis using source-generated or mode-converted shear wave energy allows differentiation of degrees of gas saturation. AVO analysis is more successful in young, poorly consolidated rocks, such as those in the Gulf of Mexico, than in older, well-cemented sediments.
Anisotropy	Variation in seismic velocity.
Carbonate	A class of sedimentary rock whose chief mineral constituents (95% or more) are calcite and aragonite (both $CaCo_3$) and dolomite [$CaMg(CO_3)_2$]. A group of minerals found mostly in limestone and dolostone that includes aragonite, calcite and dolomite. Calcite is the most abundant and important of the carbonate minerals.
Coal	A carbon-rich sedimentary rock.
Conventional	Reserves that can be successfully exploited in the current economic climate.
Clastic	Broken fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock.
Delta	There is a characteristic coarsening upward of sediments in a delta.
Dry hole	Well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.
Eolian	Eolian sandstones are typically clean and well-sorted.
Fluvial	Fluvial deposits tend to be well sorted, especially in comparison with alluvial deposits, because of the relatively steady transport provided by rivers.
Lithology	The macroscopic nature of the mineral content, grain size, texture and color of rocks.
Overburden	The layer of sand, gravel and shale which overlies the oil sands.

Paralic	Partly marine, partly continental or deltaic.
Play	An area in which hydrocarbon accumulations or prospects of a given type occur.
Stack	To sum traces to improve the signal-to-noise ratio, reduce noise and improve seismic data quality.
Reserves growth	Growth due to revision of estimate of undeveloped reserves through successful exploration.
Rift	Region in which the Earth's crust is pulling apart and creating normal faults and down-dropped areas or subsidence.
Sandstone	A clastic sedimentary rock whose grains are predominantly sand-sized. The term is commonly used to imply consolidated sand or a rock made of predominantly quartz sand, although sandstones often contain feldspar, rock fragments, mica and numerous additional mineral grains held together with silica or another type of cement. The relatively high porosity and permeability of sandstones make them good reservoir rocks.
Seal	(or cap rock), is a unit with low permeability that impedes the escape of hydrocarbons from the reservoir rock.
Shales	A fine-grained, fissile, detrital sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. It is the most abundant sedimentary rock. Shale can include relatively large amounts of organic material compared with other rock types and thus has potential to become a rich hydrocarbon source rock, even though a typical shale contains just 1% organic matter. Its typical fine grain size and lack of permeability, a consequence of the alignment of its platy or flaky grains, allow shale to form a good cap rock for hydrocarbon traps.
Structural trap	Fault has juxtaposed a porous and permeable reservoir against an impermeable seal.
Stratigraphic trap	Hydrocarbon traps that result from changes in rock type or pinch-outs, unconformities, or other sedimentary features such as reefs or build-ups.
Trap	The stratigraphic or structural feature that ensures the juxtaposition of reservoir and seal such that hydrocarbons remain trapped in the subsurface, rather than escaping and being lost.
Unconventional	Resources which cannot easily be exploited in the current economic climate; they include extra heavy oils, tar sands, gas in tight sands, and coal bed methane. The two major sources of unconventional oil are the extra heavy oil in the Orinoco province of Venezuela and the tar sands in the Western Canada Basin.
WildCat	Exploration well into an area where no production has taken place.

