# De-marginalising Small Oil Fields

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In the run up to the Scottish referendum there was heated political debate over whether 15 billion, 24 billion or even more barrels of oil equivalent (boe) could still be extracted from the North Sea. It served only to highlight the wide-ranging uncertainty surrounding the total figure.

Yet one assertion can be made with much more confidence. Whatever the extractable total turns out to be, over five billion barrels of oil equivalent contained in some 303 already known, but undeveloped fields across the UKCS could make a considerable contribution towards reaching that total. These are confirmed, appraised discoveries recorded in the IHS EDIN database used by RMRI in research for ABT Oil and Gas.

Their numbers include accumulations of all types and sizes in a range of water depths, and they have all at some stage been dismissed by the oil industry as having little or no commercial interest. Many were thoroughly appraised prior to rejection, then were plugged and abandoned or suspended while the license holders moved on to seek richer prizes. These are the marginal fields, so called because they inhabit an uncertain economic margin created by oil price, development costs and the fiscal regime.

The two principle reasons for the marginalisation of fields are their technical difficulty or their size. Either combines with their location to determine whether they are economically viable or not, since proximity to existing facilities enables projects which would otherwise prove too costly for development.

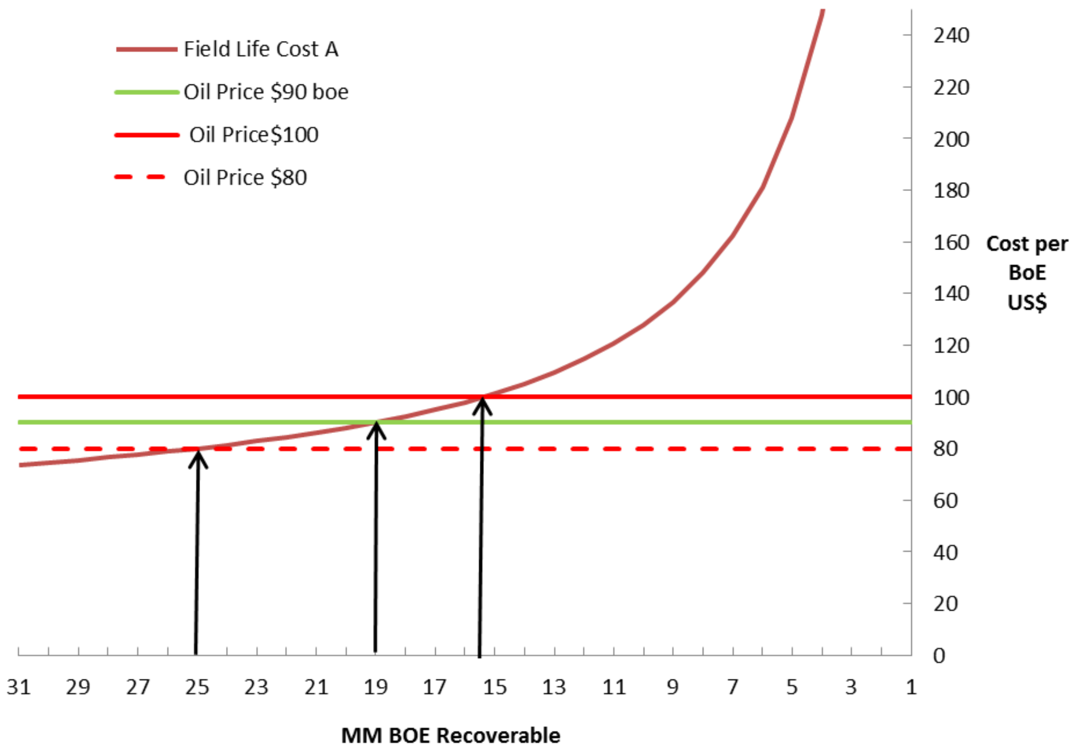
Isolated small fields are particularly interesting because they often contain conventionally recoverable, oil-rich reserves. From the IHS EDIN database, RMRI has identified 105 such fields, in UKCS waters, each containing between 3 and 30 million boe, with a collective reserve of 1.25 billion boe. Their limited output and short productive lives do not justify the capital or operating expense of conventional production methods, especially from a unit cost perspective. In a University of Aberdeen Occasional Paper, Professor Alexander Kemp and Linda Stephen stress that field lifetime costs for small fields can 'become very high on a boe basis.' [1]

This steep unit cost as field size diminishes can be demonstrated by charting the capital expenditure (CAPEX) and operating expenditure (OPEX) across a range of reserve sizes. The costs are based upon an RMRI analysis of conventional facilities with liquid processing capacities similar to the two production systems available to ABT Oil and Gas, which are discussed in greater detail later in this article. Adjusting the OPEX according to size of project, Chart 1 plots the unit cost per boe, highlighting, the point at which fields lose viability and the impact of oil price movements upon this. The precarious nature of marginal field economics can clearly be seen.

The chart makes obvious the parabolic increase of cost per boe as field size diminishes, with exponential increase at the lowest end. It also demonstrates the extreme vulnerability of small fields to any fall in oil price.

[1] *Prospects for Activity in the UK Continental Shelf after Recent Tax Changes: The 2012 Perspective.* Professor Alexander G Kemp and Linda Stephen

## Chart 1: Impact of Price Changes on Small Field Viability




A bench mark total field cost of $1280 million (£800 million) including CAPEX and OPEX, using a ratio of 5:3 is based upon a 10 million boe field from which other field costs are extrapolated. OPEX is adjusted for differences in field size on a per million boe basis by simple addition or subtraction for fields larger or smaller than bench mark size. The GB pound/dollar conversion factor is set at 1.6 and the base oil price at $90

After the spectacular fall from $140/boe to $40/boe within six months during the recession, prices have recovered to between $90 and $100/boe and have fairly settled for the past three or four years.[2] Nevertheless, within this period, there have been frequent fluctuations of around $20/boe, creating a zone of extreme uncertainty, plotted on the chart as a spread of $10 above and below the £90 base price.

At $90 per boe, fields containing 19 million boe break even, putting 83 fields this size and smaller within the UKCS below economic recovery, with a loss of 747.7 million boe[3]. Costs, however, must be considerably lower than break-even to achieve the hurdle rate for a project to be considered commercially viable and sanctioned. As such, in this model, fields containing up to 25 million boe, the average size of recent discoveries, remain at high risk. A rise in oil price to $100 drops the viable field size to 15.5 million boe, but it will attract investment only if a sustained rise is anticipated; a circumstance not expected by the oil futures market according to both US Energy Information Administration and the CME Group. This makes the prospect of a massive oil price rise giving economic certainty to small marginal fields a highly unlikely.

Price increases, then, cannot be relied upon to transform marginal field development. The macro-economic and geo-political influences that determine oil price cannot be controlled by operators,

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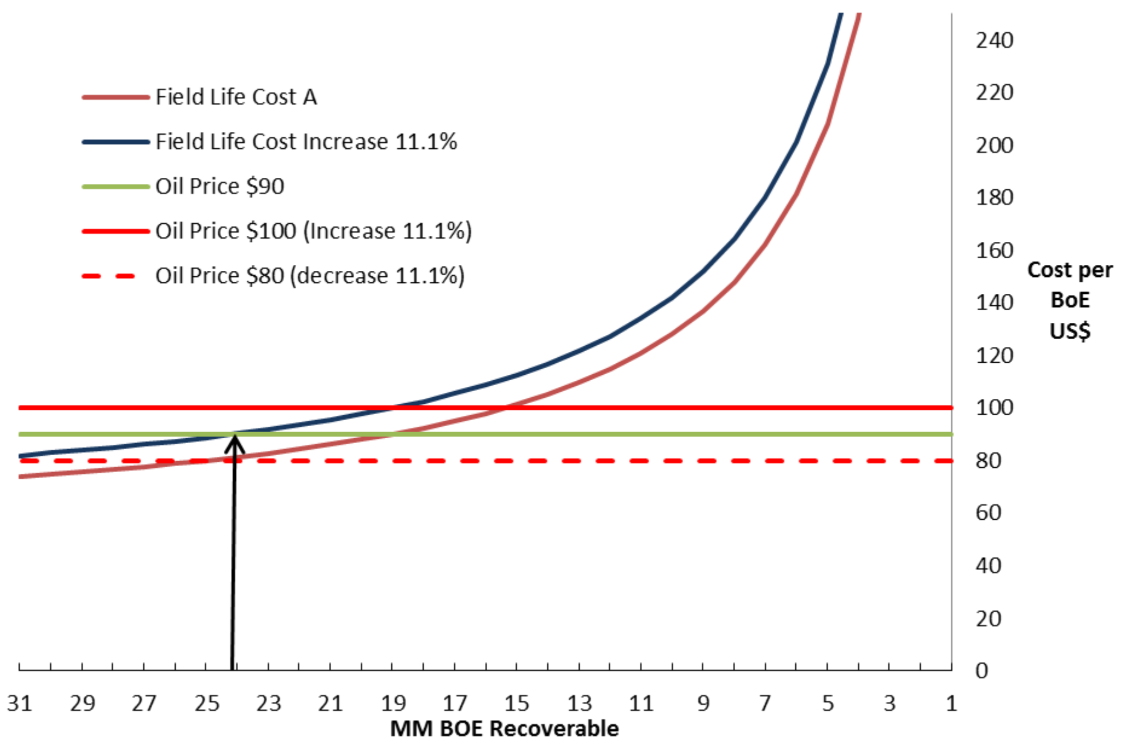
[2] Macrotrends
[3] Of 105 fields identified from IHS EDIN database

investors or even government. Besides this, when oil prices more than doubled between 2003 and 2013, any positive impact upon small field economics was limited by a massive fivefold increase in costs over the same period.[4]

Cost increases, if anything, pose a greater threat to small field development than falls in oil price. Chart 2 shows that a cost rise of 11.1% (equivalent to a $10 price reduction) takes fields containing less than 30 million boe into the high risk zone, making their commercial viability uncertain. Such an

**Chart 2: Impact of Cost Changes on Small Field Viability**




increase, or even larger, is highly probable in a maturing region where rising costs are endemic. As with price, macro-economic factors, such as international demand for labour and equipment, can influence costs, but three main causes - depletion of major reserves, the age of facilities and systemic problems of the region's fundamental development pattern - are local to the UKCS. They have meant:

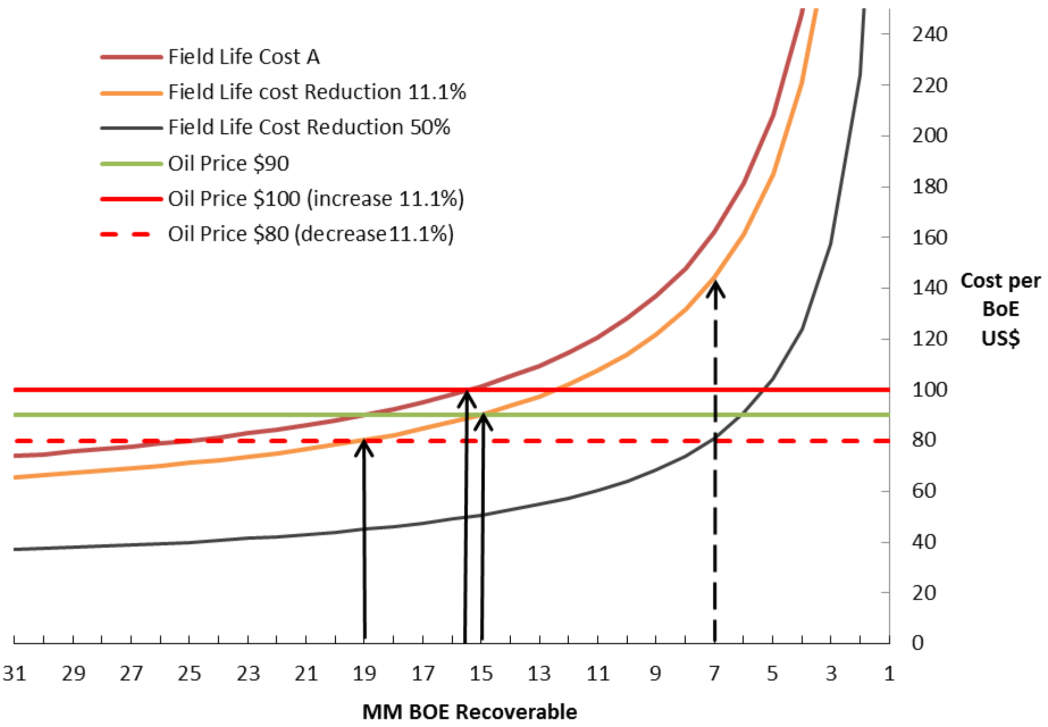
- more small fields in production, increasing unit costs;
- increased development costs for technically difficult fields, depleting fields, or frontier region projects;
- increased OPEX for maintenance and repairs
- longer periods of fully-crewed down-time, and
- periods of non-production without concurrent OPEX reduction.

[4] *The UKCS Maximising Recovery Review*, February 2014, Sir Ian Wood.

The last two points signal a major underlying problem: the accelerating effect of increased costs, especially operating costs, against declining production. This drives cost per boe ever higher and the situation has the potential to spiral. In its 2014 Activity Survey, UK Oil and Gas, says: ...in the space of 12 months, around 300 million boe of reserves are no longer considered recoverable as a result of operating cost increases that are shortening the economic life of fields.' [5] Each boe of lost production increases the recovery cost of all remaining barrels, further threatening overall economic recovery of reserves. According to UK Oil and Gas, 'This relentless rise in costs is unsustainable...' A stark symptom of the problem was highlighted by *Scotland's Independent Expert Commission on Oil and Gas*, who pointed out that 'the number of people needed to produce a barrel of oil (rose) from 18 in 2006 to 45 in 2012.' [6]

The pattern of rising costs associated with established means of production makes the future look bleak for small fields. Chart 1 above indicated that fields with reserves below 19 million boe could be permanently lost, and fields containing up to 25 million boe could be considered too high risk for development. However, unlike oil prices, with innovation and new technology it is possible that costs can be controlled by industry and government at a local level. Chart 3 below demonstrates the impact of cost reduction.

**Chart 3: Impact of Cost Reduction on Small Field Viability**




A cost reduction of 11.1%, commensurate with a $10 price increase, is shown to lower the break-even field size to around 15 million boe – almost one million barrels smaller than an equivalent oil price increase. In addition to bringing more fields within economic reach, larger fields of 19 million boe and above become less risky.

[5] Oil & Gas UK: Activity Survey 2014
[6] Scotland's Independent Expert Commission on Oil and Gas: *Managing the Total Value Added.*

However, many of the fields containing between 3 and 30 million boe identified by RMRI remain uneconomic. To achieve their viability a much greater reduction would be required. As demonstrated by the 50% reduction line, halving costs would reduce viable field size to 7 million boe which would need a price rise to $140/boe. Though very small fields remain at risk, with a potential loss of 53 million boe, cost reductions are shown to have more impact upon the economics of marginal fields than comparable oil price increases.

Whether the level of cost reduction required to unlock small fields can be achieved by conventional means in the UKCS is highly unlikely. Though smaller accumulations have a major contribution to make to the wider economy, left to established methodology, only a small fraction of their 1.25 billion boe is likely to be recovered.

The established development model for the UKCS is a dendretic outgrowth of host platforms and pipelines from major production installations and arterial delivery systems designed to exploit huge fields. Extending this to include smaller and more marginal fields has, so far, been the favoured method small field exploitation. According to James Harpin, more than half of the small fields developed in the UK North Sea between 2000 and 2010 'depended upon subsea infrastructure tieback to host processing and export facilities'.[7] For fields within reach of suitable platforms this has proved cost effective and will, according to Sir Ian Wood, be further enabled by the cluster development advocated in his *UKCS Maximising Recovery Review*. [8]

If, however small fields can be developed only through linkage to existing infrastructure, as Sir Ian Wood implies when he says, ‘tieback enables small fields to be developed which would have been uneconomic on a stand-alone basis’[9], then the numbers exploited will be severely limited. Since tieback costs increase with distance, it will confine small marginal field development, and much exploration activity, to the catchment areas of existing facilities. Extending beyond this will require an additional complex network of subsea facilities, pipelines and intermediate host platforms, with obvious future decommissioning cost implications.

More crucially, small projects, already economically vulnerable, would continue to be linked to an increasingly costly ageing infrastructure, including major platforms whose primary fields are severely depleted and whose own future is insecure. Many production facilities require increased throughput from satellite fields to remain economic so, unless several robust projects are within geographical reach, the security of the host, and therefore all its dependent fields, will be dictated by its economically weakest satellites.

These problems of existing infrastructure network must inevitably be passed on to third parties seeking to link into that network. For example, even if owners of fixed installations are reluctant to inflate tariffs, the higher expenditure or looming decommissioning costs encountered by many will force a lease rate increase.

Floating Production storage and Offloading (FPSO) vessels provide a means of sidestepping these difficulties. However they were designed for medium to large accumulations, have 24/7 crewing requirements and a high front-end CAPEX which is reflected in lease rates. In addition, with some 20

[7] ***Measuring the impact of aging infrastructure in the UK North Sea*****,** James Harpin **IHS**
[8] See Footnote 5
[9] Ibid

- 23 FPSOs operational in UK waters, [10] coverage and availability is limited and any increase in demand is likely to have a high impact upon costs.

Licence holders of marginal fields, typically small operators for whom these accumulations could provide game changing opportunities, are particularly susceptible. They are positioned at the interface between the economic requirements of their low-volume, short-life projects and the established UKCS production system, with expensive FPSOs as their only alternative. They are likely to encounter major difficulties in the early project stages as they try to find an economic means of utilising existing facilities. Some of these difficulties, which could precipitate project abandonment, might include:

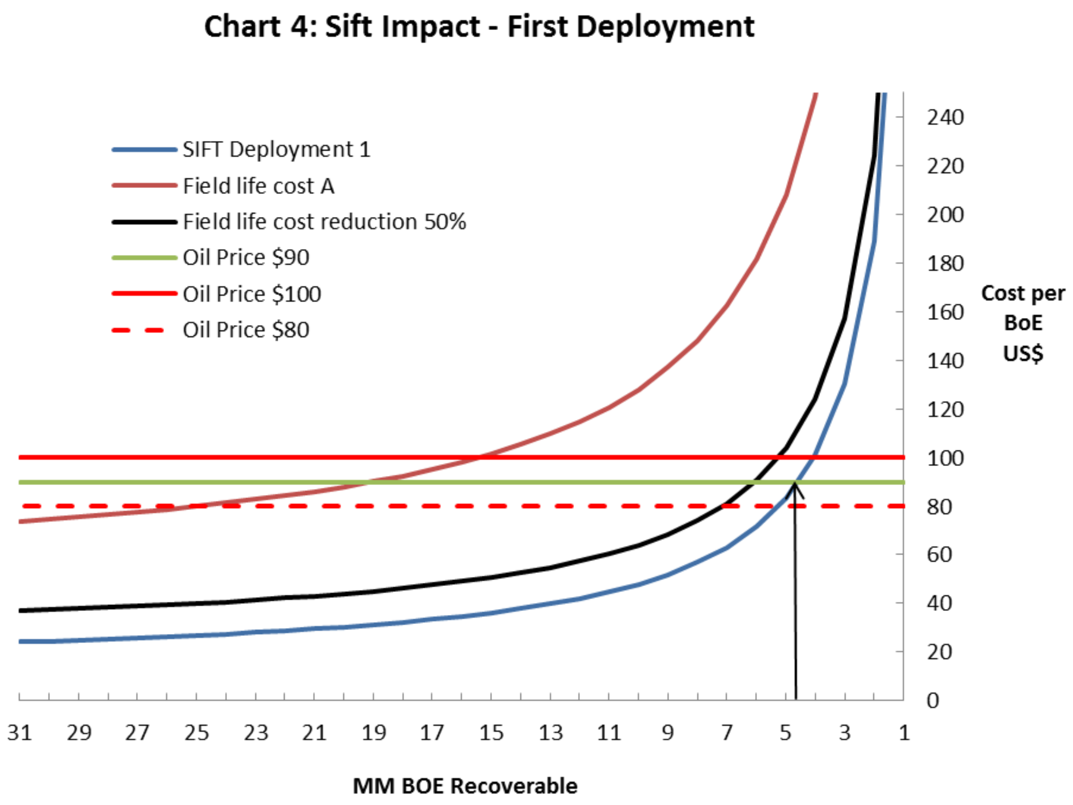
- inability to negotiate economic terms with infrastructure owners;
- anticipated space on facilities being withdrawn;
- key partners pulling out;
- higher than anticipated costs revealed during the Front End Engineering Design (FEED) or pre-FEED stages;
- lack of suitable production and delivery facilities within viable distance, or
- difficulty agreeing appropriate financing solutions and attracting required investment.

These examples indicate the hurdles which must be overcome if the potential contribution of marginal fields to the economic recovery of the UKCS is to be maximized. Part of the remedy is highlighted in *Scotland's Independent Expert Commission on Oil and Gas* when it stresses the requirement for smaller specialist companies in the region, and the need to attract 'agile, entrepreneurial, and therefore often smaller players'.[11]

This aptly describes British company ABT Oil and Gas (ABTOG). The company has long recognised the need for a new sector within the upstream oil and gas industry, focussed upon the economic extraction of small or stranded fields. As a result ABTOG are creating the next evolution in offshore oil production: buoyant solutions which can unlock the potential of such accumulations. Central to this is the need to drive down costs and, at the same time free small operators from dependency upon existing infrastructure. Through innovative production and storage systems, ABTOG's buoyant solutions provide the appropriate means to deliver these two crucial elements.

Having identified appropriate solutions, ABTOG worked with its partners to develop two stand-alone production systems both of which secure dramatic reductions in both CAPEX and OPEX; a taut-tethered Production Buoy and, along with GMC Ltd., a solution specifically cost-effective for the North Sea, which they call the Self-Installing Floating Tower (SIFT). The potential impact of the SIFT on small field development is shown in Chart 4, below. As this demonstrates, the SIFT is able to reduce cost to a lower level than the 50% cost reduction detailed in Chart 3.

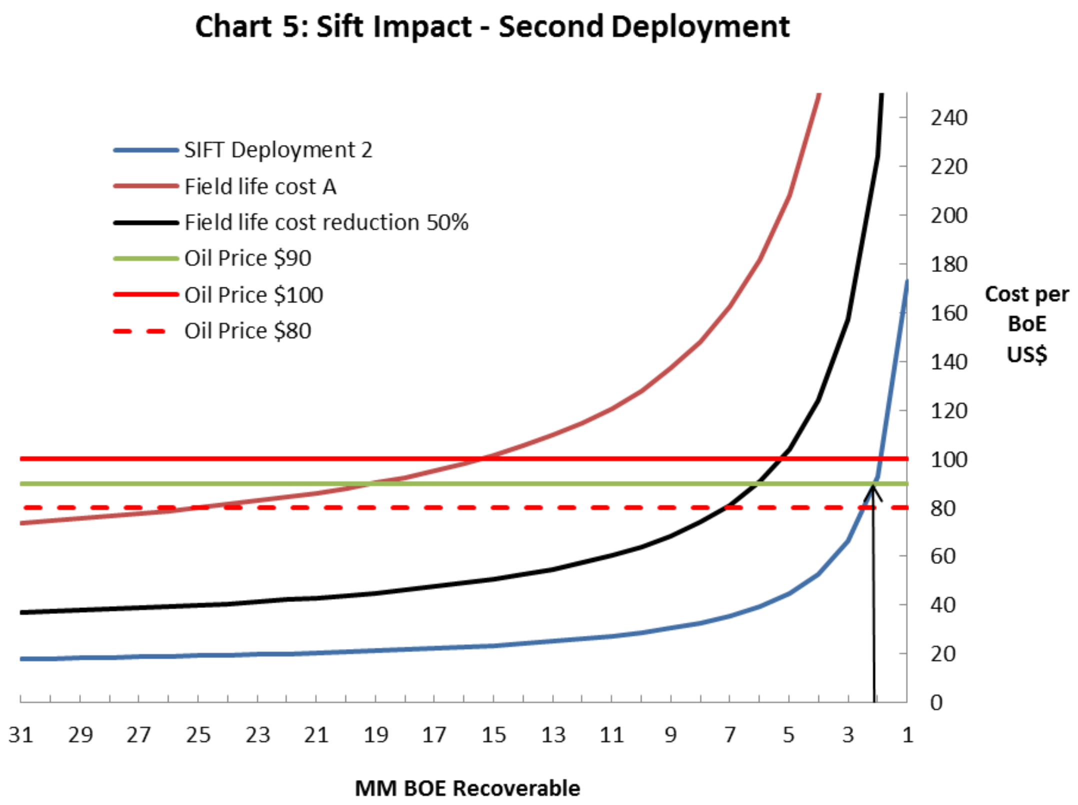
[10] Culled from information listed on fpso.net; fpso.com and *A Barrel Full.*
[11] See Footnote 5




For an initial 10 million boe project, use of the SIFT reduces field-life cost by around 60% of the cost of a comparable established production system. Including generic CAPEX and abandonment costs of $350 million (£220 million), and an OPEX around $130 million (£80million), total cost for a field of this size is $480million (£300 million). This brings the break-even field size to below 5 million boe, and reduces risk for fields containing about 5.25 million boe.

Both the SIFT and the buoy utilise innovative adaptations of proven technology enabling dramatic cost reductions through lower construction costs than alternatives. They contain all the equipment needed for processing up to 20,000 barrels of fluid per day, adapted for use in low-cost buoyant housing structures. OPEX is held down to a minimum as normally-unmanned operation cuts back crewing costs. There is also capacity for integral storage in the cellular legs of the SIFT, or in a separate seabed tank for the buoy, so tanker offloading avoids the high delivery tariffs of existing pipelines and infrastructure.

Most importantly, the buoyant nature of these systems, linked with ease of installation, simple decommissioning and low-cost refitting and transportation, means that they can be redeployed – possibly several times over during their 25-year design life. Costs are almost halved to around $288 million dollars (£180million) for subsequent deployments, reducing the viable field size by another 2 million boe as shown in Chart 5.

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From this it is clear that the SIFT renders fields containing 5 million barrels economically viable during its first deployment, and pushes this figure to below 3 million for second and subsequent deployments. Further than this, the tightening curve of the cost parabola's 'elbow' means the lower 'arm' falls quickly away from the high risk zone, reducing the overall economic vulnerability of all fields containing above 3 million boe. Though real field conditions and project parameters will vary, this gives an indication of the cost reductions that can be achieved using ABTOG's solutions. Further reductions might come from:

- refinements of design and construction;
- tying in multiple wells, or by
- identifying similar target field, either within geographical clusters or in scattered locations, reducing refitting cost and time.

With these advantages, the solutions offered by ABTOG have more to offer than a means to exploit known small accumulations. Sir Ian Wood complains that, 'There has not been a significant (multi hundred million) discovery for five years.' This makes the need for solutions to the recovery of small marginal fields even more imperative. With the average size of discoveries now around 25 million boe, a way of developing smaller finds is crucial. Apart from the revenue that such discoveries will provide, if exploration continues to be severely curtailed through fear of sub-economic finds, as the Wood Review suggests, then new discoveries will become fewer and some huge, but as yet unsuspected, accumulation might never come to light. There is therefore an urgent need to revitalise exploration by providing the means to transform small, isolated discoveries into economic finds.

Even without new discoveries, identified small fields alone could produce a post-tax profit of £22 billion and boost tax revenue by £19 billion. Further than this, all fields decline and at some point all fields will become marginalised, making their existing facilities uneconomic and decommissioning inevitable. When this happens, ABTOG's solutions could sustain hydrocarbon production from isolated locations throughout the region long after its fixed structures have been decommissioned and cut up for scrap.

Now that the custodian of the UKCS is decided, the UK government must put aside arguments about the size of the region's hydrocarbon potential and focus on how it can maximise the economic recovery of offshore reserves. Regardless of how much oil remains in the maturing North Sea, small and stranded fields must be transformed from marginal assets to become a key component of the nation's energy security and economic prosperity for decades to come.