The North Sea in a Global Context: A BP View

*By Tony Hayward**

What I'd like to do today is to look forward to the challenges that the North Sea will face in the future – there's probably not a better location to do this and the timing is right. Over the last 12 months or so it has become clear that the UK North Sea is at a turning point in its evolution.

Having enjoyed 30 years of uninterrupted growth, it now faces the prospect of decline as existing fields are depleted and new finds become fewer, smaller and more costly to develop.

This does not mean that the UK North Sea is in "harvest mode", and as I will discuss in my remarks, I believe there are steps the industry and the government can take together to create a new future for the UK North Sea.

Agenda

So my agenda is to briefly cover:

- the history and outlook for the industry,
- summarize BP's position as seen through the eyes of a global super-major,
- reflect on the challenge of creating a new future – in the face of a seeming inexorable decline,
- and to look at the global competitiveness of the UK North Sea in light of the fiscal changes introduced in the recent budget.

Production Outlook

Let me begin with the track record – always a good place to start:

From the early seventies through the mid-eighties, the North Sea enjoyed significant growth in production. This was driven by large scale finds including BP's own Forties field.

By the mid-eighties oil prices were lower and we faced a future production decline that, at the time, seemed similar to today. The big fields were in decline and squeezing more production and acceptable returns out of current and future developments became a greater challenge.

However, as many of you know, both industry and government met that challenge; new field development filled in many gaps in the map and volumes rose again through the nineties.

Specific interventions at this time were the CRINE cost reduction initiative led by industry, and Government's role in the elimination of PRT and in gas market liberalization.

So, where are we today?

The generally accepted view is that we are about half way through the basin's life.

The White Zone in the West-of-Shetlands, once seen by both BP and the industry as the opportunity to maintain current levels of production, has seen extremely disappointing exploration results.

Future exploration will add more reserves and one-off successes such as Buzzard will still occur. But for the most part, new finds will be smaller, fewer and more spread out.

Basin production will be increasingly dependent on better technology, improved recovery from mature fields, and efficient development of remaining discoveries such as Clair.

The next 2-to-3 years will see the onset of a production decline, which is likely to accelerate beyond 2005. The challenge the industry and government face is how to create a future that manages decline in the most efficient way to ensure that every possible barrel of oil is recovered.

BP at a Turning Point

BP's story in the UK North Sea mirrors industry experience over the last decade.

Through the 1990's we grew production at 5% pa and reduced unit costs by about 3% pa over the same period.

We developed numerous new fields. Significant post '93 investments included ETAP, Foinaven and Schiehallion. All required new technology and innovation, and were enabled by the change in fiscal regime in 1993 when PRT was removed.

The challenge today looks very different from a decade ago:

- Our base production has begun to decline from highs in 2000 and 2001, and most importantly, we don't have the same development opportunities as a decade ago. Clair, Rhum, Devenick and others are important but they're no substitutes for Bruce, Miller, Schiehallion, Foinaven, and ETAP …and as I have already noted the White Zone failed to deliver any major new discoveries for BP.
- Investment has shifted to infill & mature field investments. In the nineties we drilled infill wells mainly in Forties and Magnus… today we are active nearly everywhere. Almost 50% of our capital in 2002 will be invested in infill drilling in mature fields.
- Going forward, we must manage decline in the most economical way. That means keeping unit production costs flat as base production decreases and utilizing infrastructure and economies of scale that are available today, but that probably will not be available a decade from now. All of this is, of course, predicated on the basin remaining competitive in a global context.

BP Resources: Opportunities and Challenges

Let me now turn to BP's North Sea resource base, which is probably broadly reflective of the North Sea as a whole and certainly serves to illustrate the nature of our future challenges and, I believe, the industry's at large.

We have some 5bn boe of future resources including barrels beyond current technical limits. Just to put the North Sea in context – that is more reserves than in the Deep Water Gulf of Mexico where we have some 3bn boe net, and Azerbaijan where we have some 1.5bn boe – so the North Sea remains immensely important to BP and we expect to be doing business here for a very long time to come.

The "base", or already-producing reserves, contains developed reserves in excess of 2bn boe. This base requires ongoing investment and, operational and cost -control excellence.

We also have more than 1bn boe of what we refer to as

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"quality development options". These include fields such as Rhum, Devenick and Clair, and infill opportunities in existing fields. These will be the focus of our investment activity over the next few years.

We also have a significant tranche of reserves, more than 1bn boe, of "marginal development options", which are not likely to attract investment today.

However, we know what we need to do to access them. The opportunities here need lower cost wells, enhanced oil recovery schemes or low-pressure gas operations.

The key to producing these reserves will be the application of technology such as 4D seismic, through tubing rotary drilling and additional compression. Accessing this significant prize is a major challenge.

And finally, a more elusive prize of 1bn boe exists beyond our current technological capabilities.

So there is a lot to go for. How are we going about it?

Creating the Future

There are three key levers:

- The application of the right technology,
- The creation of commercially innovative solutions, and continually reinventing our business processes to lower unit costs and realize productivity gains.
- All of these can only work if they take place in an environment of fiscal stability and global competitiveness – something I will return to later.

Technology

Let me start with technology.

Increased recovery factors in mature fields such as Forties reflect the ongoing delivery from technology. 4D seismic is one of the key applications. It has proven particularly successful in fields like Forties, Foinaven and Schiehallion where un-swept areas of the field provide the best infill targets.

Having identified un-swept oil, we need to access it at lower costs. In Alaska we succeeded in reducing access costs by 75% using Coiled Tubing Drilling – the challenge is to replicate that performance in the North Sea.

In the West of Shetlands we are in the process of designing wells for subsea through tubing rotary drilling at low cost. Through tubing rotary drilling and multilateral drilling will be key levers for accessing mature reserves.

Most of our new developments will be satellites. The next phase of ETAP is underway with the development of the Mirren & Madoes satellites. This is a great example of commercial consolidation unlocking the developments.

Other major satellites will be Rhum and Devenick. For Rhum, we are looking at a sub-sea tieback as a development option over a distance of 45km. This would be one of the longest high-pressure sub-sea tiebacks in the world.

The few remaining green-field developments such as Clair demonstrate how we have managed to unlock marginal fields by bringing Gulf of Mexico learnings and global best cost to the UK North Sea.

Commercial Innovation

Let me now turn to commercial innovation.

We support and promote the need for change and have been very active in this area.

We've reduced our fallow acreage portfolio from 200 blocks to 50 and are actively working on the rest.

We can't stop here. The industry needs to become even more innovative as we head into maturity. The key areas to address include redevelopment of old fields and decommissioning.

BP has a long history of commercial innovation in the North Sea.

MAST, the mature assets team which transformed the potential of Beatrice, Buchan and Clyde fields, was at the forefront of this. As the operator of ETAP we brought a collection of marginal fields together to create a giant oil and gas field.

More recently we have taken the Satellite Accelerator concept into the area of mature field redevelopment. Through this initiative, we are attempting to combine BP and supply chain expertise with 3rd-party investment to access a significant redevelopment prize in the Northern North Sea Don field.

Another key area we must deal with is decommissioning. This has the potential to continue to be a major barrier to trades. We are considering more innovative ideas such as the temporary farm-outs of assets when they don't meet our investment criteria.

More recently, the Magnus enhanced oil recovery scheme is an extra-ordinary example of commercial innovation at its best.

Magnus EOR

Gas that was previously flared or reinjected in the West of Shetlands is now piped through a new sub-sea pipeline to Sullom Voe for enrichment with gas liquids; and from there it flows through another new line to Magnus for injection into the reservoir for use in an enhanced oil recovery scheme – that will add 50m bbls of field reserves and extend field life beyond 2015.

When the gas comes out of the reservoir, it will then be piped to the gas processing terminal at St Fergus, north of Aberdeen.

The commercial agreements required to complete this project involved the JV partners in Schiehallion, Foinaven, Sullom Voe, and Magnus; more than 30 different companies in all.

Business Processes

Let me now talk about business processes and some of the things BP is doing to keep investment spending in the UK while at the same time unlocking the full capability of our suppliers

Over 80% of our third-party spending in the North Sea is with UK companies. This year, that represents 80% of around $2.3bn, including $1bn in capital expenditures.

Up to 10% of our annual expenditure is with Small to Medium Sized Enterprises or "SMEs". We see these companies as an important source of innovation, which is critical for the future of the North Sea – it is vital that we unlock more of this potential and make it easier for smaller companies to gain access to companies like BP

In that regard we have run a number of "Share Fairs" for suppliers and contractors and SMEs to share our future plans.

We've also worked closely with government on these issues. We've been an active participant in the DTI sponsored SME mentoring program where a number of our younger high-potential staff have developed mentoring relationships with SMEs.

We have also been active participants in the PILOT Progress Partnership Work Groups and contract initiatives and have signed up to the industry's commercial code of practice welcomed by government earlier this year.

In the second half of last year, we began to re-engineer our own internal business processes with the objective of delivering Great Operating performance.

With the Great Operator or GO business process we are focusing on key operational performance levers; making investments in intellectual capital, rather than financial, and driving for best in class across all our operations – a 25% increase in performance.

This means being able to minimise the production decline rate of our mature fields by excellent reservoir understanding and management, by drilling the very best infill wells at significantly lower costs, by achieving world class standards in the way we execute our projects, and by keeping our facilities – be they platforms or pipelines – operating as close to 100% efficiency as we possibly can.

One of the other important consequences of our Great Operator drive will be continued progress along our journey of eliminating injuries to our people. Over the past decade we have already reduced the incidence of injuries more than 10 fold, and are now approaching industrial world-class performance.

The DAFC frequency rate for all our North Sea operations year-to-date is 0.05 a fantastic achievement – one that the North Sea team is rightly very proud of!

Role of a Super-major

Let me now turn to the role of a super major.

BP is a strong believer that there is room for everyone in the North Sea – from super-majors, medium sized independents, new entrants and niche players.

So where can we contribute in a distinctive way?

The scale and the consistency of our investment is important. This year we will be investing around $2.3bn in total in the UK North Sea, including $1bn in capital. That has a significant impact on the supply chain – as I've already said - with the right investment climate - we have the financial strength to maintain this level of spending through the cycle – perhaps in a way that smaller players may find difficult.

We bring a global perspective to the UK North Sea – the ability to transfer learning from other provinces – for example, deepwater Gulf of Mexico expertise applied to the West of Shetland, and the reverse, of course, applies.

Our diverse portfolio and breadth of activity mean that we can generate options and take risks that others cannot – the Magnus EOR is an excellent example of that.

And we can play a major role in the industry leadership needed to take the North Sea forward and create a new future… most recently through PILOT and related initiatives.

This brings me to one of the issues that is facing the industry today – the need for fiscal stability.

Global Competitiveness

I have highlighted examples of resource expansion and production growth enabled by both management excellence in the industry and a stable fiscal regime provided by the government.

The stability of the fiscal regime had encouraged the industry to focus on the remaining potential of the area – up to 18bn bbl of oil, and up to 90 TCF of gas which has yet to be produced or developed – and had led to the situation where, against all predictions, we were seeing a continued increase in production – to a new peak of 2.5m barrels of oil and 10.9bn cubic feet of gas per day next year.

The stability could not offset eventual decline, but it had succeeded in extending the life of the whole province, in maintaining our self-sufficiency in oil and gas for much longer than predicted and in sustaining the 265,000 jobs which depend on the North Sea, including a very large number in Scotland.

Unfortunately the situation changed with the recent budget statement.

As a company, and indeed the industry, we have previously commented on the impact of the budget – the estimated £8bn which will be lost to the industry through to 2010, the uncertainly over the timing of the abolition of Royalty, and the now very high marginal tax rates on our oldest fields – the very ones in which it is necessary to continue to invest. Our challenge now is how to maintain the profitability of a business that has been severely hampered by a significant windfall tax.

The measures announced in the budget did a number of things:

They took money out of the business – in total nearly £8bn will be lost to the industry through 2010, and even at $15 per bbl, £4bn would be lost over the same period.

The government increased taxes on profits but left in place a regressive tax – royalty – with removal mooted but not delivered – creating a degree of uncertainty which doesn't help anyone planning investments to recover more oil and gas from established fields such as Forties or Magnus.

And they put into place a new regime designed for a high oil price world, which takes no account of the possibility that prices will fall back to their long-term average – which is around $18-$20 per barrel.

The global competitiveness of the North Sea has been reduced by the fiscal changes, and this is unfortunately likely to lead to reduced investment and to hasten the decline in production.

BP believes, therefore, that further changes in North Sea taxation are now required. The sooner these can be agreed, the greater chance of minimising the damage caused by the Budget. The abolition of Royalty and the allowance of Financing costs are, of course, necessary, but by no means, sufficient improvements. Without further changes, BP and other companies will find it much more difficult to justify the sort of investments, particularly in mature fields, which can significantly prolong the life of the North Sea.

Their direct impact will be compounded by the fact that a change made in this way, without consultation with the industry, reduces the confidence in the stability of the regime going forward and imposes an added element of risk on all future decisions.

The tax system which was in place prior to the budget wasn't perfect but it was effective.

Its effectiveness was demonstrated by the level of

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