

BG GROUP



BG Group

2009 Fourth Quarter and Full Year Results and
Annual Strategy Update

5 February 2010

Sir Robert Wilson, Chairman

Ladies and gentlemen, good afternoon to you all and thank you all for coming today. For those of you that I haven't met, I'm Robert Wilson, the Chairman of BG Group. You all know, I think, Frank Chapman and Ashley Almanza. Now, they're going to be talking to you about our results for 2009 and Frank is obviously going to be spending quite a bit of time talking about the future and our plans for the future.

Just before handing over to Frank though, perhaps I can reflect for a moment on what's been happening over the last three or four years. Because if you think back just three or four years, and many of you have been coming to meetings for longer than that I know, an awful lot has changed for us; because go back then and in fact we weren't talking about so called unconventional gas, we weren't even talking about that. In fact, the first time we mentioned it to you was at this meeting two years ago when we'd just completed the joint venture agreement with QGC, the first of a series of transactions.

Now of course unconventional gas in one form other another, whether it's coal seam gas, or whether it's shale gas is going to be a very big part of our future and indeed our industry's future. Because three or four years ago coal seam gas and shale gas were very small production items in Australia and in the States in particular for sale into local markets. But it wasn't a big scale resource, which is not the way that we see it now at all. And of course going back four years and we were really in the very early stages of our expansion - developments that you're going to here more about today there.

Now in Brazil as you already know, we're talking about \$20 billion of capital expenditure over the course of this coming decade and it's not going to be a long way short of that as far as Australia and our developments there are concerned. And that's just on what we know today and the opportunities that are already in our portfolio today. So there's likely to be more coming I think whether it's in Brazil or in terms of unconventional gas.

Now that I think is an indication of just how fast things have changed, both for our industry and for this company and the sort of responses that the company has put in place. And I think we would feel very confident about our ability to participate in a high range of opportunities in all of these sectors going forward.

The other point which I'd just like to draw your attention to, because I think it's quite important. If we were putting the clock back four years ago and looking at our geopolitical risk profile then it was probably pretty much average for the sector, it was okay. But some of the projects that we were looking forward to, as immediate parts of our plan over the next five years, ten years were in relatively higher risk areas. In other words, we were going to see a progressive deterioration of the geopolitical risk profile of BG.

But that's not what's happened, because with the investments in Australia, Brazil, the United States I think they would all, including Brazil incidentally; they'd all be regarded as relatively low geopolitical risk. And I think there is a marked change both in the profile you see of the company today and the way it's going to develop over the next decade with a much lower risk profile than we might otherwise have expected.

Anyway, I just wanted to say those few words before passing you over to Frank to get into the meat.

Frank Chapman, Chief Executive

Thank you Chairman.

Good afternoon ladies and gentlemen, and welcome to BG Group's fourth quarter results and strategy presentation.

Before I get going, I would like to draw your attention to our legal notice.

In a moment, Ashley will take us through our 2009 results: *resilient* results achieved in a challenging business environment.

After that, I'm going to show you what the next decade holds in store.

It is, I believe, an exciting future.

You'll see how BG Group is entering a new decade of high growth.

We'll describe how the confidence we have in delivering that growth is underpinned by a strengthened and rebalanced portfolio.

You'll appreciate how key projects are being significantly and rapidly de-risked.

You'll see how we already own the reserves and resources needed to meet our growth ambitions. And you'll recognise BG Group's potential to extend our track record of growth, and shareholder value creation deep into the future.

Now to give shape and substance to this exciting future.....these are the key messages we'll focus on today.

- First, we'll show upstream growth to 2020 at the upper end of our 6 to 8 percent per annum target range, together with progress towards our 20 million tonnes per annum LNG goal for 2015.
- Second, we'll emphasise that Brazil, with BG Group net reserves and resources of more than 3 billion barrels oil equivalent, is a story about *today*.
- Production is already under way, and will ramp up strongly in the first half of the decade, on a steep trajectory to more than 400 thousand boe per day, net to BG Group, by 2020.
- Third, we'll show excellent progress towards sanction of QCLNG in 2010; a project firmly underpinned by up to 8.3 million tonnes per annum of LNG agreements – and with QGC's discovered reserves and resources now standing at 17.3 trillion cubic feet.
- Fourth, we'll show the excellent progress being made with EXCO in the US. We expect EXCO to contribute 100 thousand boe net production by around 2015.
- Fifth, we'll disclose new guidance for LNG profits of \$1.8-2 billion per annum for the years out to 2012. This provides assurance of sustained performance in LNG, despite the current business environment.
- And finally, we'll show you a reserves and resources increase of some 1.4 billion boe, bringing the total to around 14.5 billion boe.

And we'll present a scenario achieving upstream production of 1.6 million boe per day by 2020.

The detail on all this, however, lies in the second half of the presentation. First, I'd like to ask Ashley to take us through our 2009 results.

Ashley Almanza, Chief Financial Officer

Thank you Frank; and good afternoon ladies and gentlemen.

Before we review the operating segments let me summarise the Group's performance and outlook.

- The Group has delivered solid earnings and cash flow. Over the year, benchmark oil prices fell by 37% and Henry Hub fell by 53%. Against this background Group earnings per share fell by only 27% to 67.3p/share.
- Cash conversion was once again strong, with cash flow from operations of £4.9 billion;
- This strong financial performance was underpinned by the strength of our integrated business model and, in particular, our approach to marketing gas and LNG.
- We funded the acquisition of Pure and the joint venture with EXCO, from our cash resources and ended the year in a sound financial position with gearing of 17%; and
- The Board has recommended a 10% increase in the full year dividend reflecting its confidence in the Group's prospects.

Those are the highlights.

Now before we look at the results in more detail, I'd like to remind you that from the first of January this year we will be reporting in US Dollars. Our guidance for 2010 and beyond will therefore be given in US Dollars, so it may be helpful to note that our average US Dollar translation rate during 2009 was one dollar and fifty five cents to the pound.

As I've already mentioned, we saw sharp falls in benchmark oil and gas prices. The Group's solid performance in the face of these challenging trading conditions can be explained by four factors – firstly: the growth in our E&P business – with volumes up 8% in the quarter and 4% for the full year. Secondly another strong performance from our increasingly stable LNG business; thirdly – the recovery of substantially all of our past gas costs at Comgas; and lastly the benefit of a stronger US dollar.

Below the operating line, we had full year net finance costs of £144 million. This included a benefit of £25 million from currency gains – an amount I'm sure you will want to remove when estimating financing costs for 2010.

Our effective tax rate was 42 %, and this is also our estimated rate for 2010.

Now let's turn to E&P.

In addition to lower prices, the result in our E&P segment was affected by weaker gas demand and a higher exploration charge. Annual volume growth of 4% was lower than expected and this was mainly due to weak gas demand in a number of our markets and the delayed start-up of the new Hasdrubal field in Tunisia. I will comment later on our outlook for demand and volumes but am pleased to report that Hasdrubal is onstream and production is now ramping up.

Full year exploration expense was £ 600 million which was higher than expected because of the cost of the Boi well in Nigeria and the write off of a number of non-core exploration properties. In 2010 our drilling plan is weighted towards development drilling and the total cost of our exploration program is therefore lower, at some US\$1.4 billion, with an expense charge of around US\$ 700 million.

Very good progress has been made with reserves replacement - driven by the appraisal and development of our rapidly growing resource base.

The left hand chart on this slide shows our reserves replacement for 2009.

Our proved reserves replacement ratio was 160% even after a price related reduction of 203 million barrels, primarily relating to Karachaganak.

During the year we also added proved reserves through acquisition, mainly EXCO. On an organic basis our proved replacement ratio was 119%.

The right hand chart shows our 3 year replacement ratio against an industry peer group and demonstrates top quartile performance over a longer period. Our three year replacement ratio was 166%.

Going forward, we anticipate a healthy reserves replacement ratio as we continue to develop the portfolio and move our large discovered resource base through to proved reserves. Now, as you know, reserve replacement flows through to unit Finding & Development costs.

This slide shows our F&D cost performance against the industry in recent years. As you can see BG has maintained a top quartile position.

And the strength of the Group's project portfolio means that we can expect to maintain a competitive position in future.

Our next slide shows unit opex.

BG has been a top quartile performer on this metric for some time. For 2009, our unit Opex, at around \$6 per boe, was broadly in line with our guidance, and we therefore look set to maintain our top quartile position. For 2010, we expect unit opex of around \$7 per barrel due to the effects of higher prices on royalties, a larger well work-over program and the effects of higher unit costs in Brazil and Australia as we

prepare for production ramp-up. Some of these effects are temporary and we expect unit opex to decline in 2011.

Overall then, we have assembled a portfolio that, we believe, will enable us to sustain our competitive cost performance for many years to come.

I'd like to turn now to the LNG segment.

During 2009 we saw a slower build up of the industry's LNG supply. Against that background our Shipping and Marketing business made an operating profit of £1.4 billion down just 6% on the previous year.

Profits from liquefaction in the year rose by 46% to £211 million as Egyptian LNG received higher income under its tolling contract.

For the LNG segment as a whole, we posted operating profits of almost £1.6 billion despite the significant falls in Brent and Henry Hub prices. This strong performance reflects the benefits of our early decision to diversify our sales book and lock-in our margins.

In Transmission and Distribution total Operating Profit was £426 million reflecting the recovery of £162 million of past gas costs in Comgas. The level of recovery in the fourth quarter was ahead of our expectations, which means we have only £12 million of past gas costs carried forward into 2010.

Looking at Comgas' trading performance, we saw a 20% drop in volumes due to the combined effects of the availability of hydro-electric power and weak industrial demand.

I'll also deal with the Power segment here. In 2009 we posted an operating profit of £158 million pounds, which benefitted from improved operating performance in Italy and the USA and favourable exchange rates.

Let's now turn to the outlook for the business, starting with the E&P segment.

We are making major investments in Australia, Brazil and elsewhere across the portfolio and these investments will support high levels of growth out to 2020.

As we have said before, this growth will not be linear and as you can see from this chart, we expect only slight growth in 2010 before production begins to ramp up in 2011. Production then rises rapidly from 2012 with a growing contribution from Brazil, Australia, the US and the start-up of Bongkot South in Thailand and Jasmine in the UK.

The demand weakness we saw in some markets during 2009 is expected to continue through 2010 and to begin recovering in 2011 as economies around the world return to growth at different speeds.

2010 will also feel the effects of the delayed ramp up at Hasdrubal and reduced entitlement at Karachaganak following the re-phasing of the investment program.

In a moment, Frank will provide more detail on the portfolio of projects which underpin production growth at a compound average rate of 6-8% per annum all the way out to 2020.

Turning to the outlook for LNG

This slide summarises the performance and profit outlook for the LNG segment as a whole.

The LNG segment now makes a material contribution to the Group. There has been some concern in the market as to the sustainability of our LNG profitability – I think largely because of the challenging conditions in the global LNG market. Although we expect conditions in the LNG market to remain challenging in 2010, we are pleased to extend our guidance and confirm that we expect the LNG segment to generate operating profits of \$1.8 to \$2 billion in each of the next three years.

This chart shows our projected LNG operating profit for the period 2010 to 2012. You can see that most of this profit is firm - based on a high proportion of locked-in LNG sales and largely fixed liquefaction tariffs. Total profit for this segment is therefore relatively insensitive to changes in oil and gas prices.

In 2010, we expect broadly similar results for each of the quarters.

The stable financial profile together with the development of a material low cost supply position in Asia, underscores once more the substantial value of our LNG business.

Turning now to our capital investment, our spend during 2009 was £5.2 billion pounds. This included £1.1 billion on Pure Energy and the EXCO joint venture.

Looking ahead, we expect our capital investment programme to be \$7.5 billion this year and to average \$8 billion per year over the three years to 2012. Our major projects in Brazil, Australia, the US and the UK are the main drivers of this investment programme.

I'd like to take a moment to compare this with the capex program we laid out last year

Our previous capex guidance of £4 billion per annum over the 2010-2012 period was at an exchange rate of \$1.50 to the pound and thus equivalent to \$6 billion.

We have also rebased our forecast for the change of our reference conditions from a \$55 to a \$70 per barrel cost environment. The change in assumed exchange rates for our non-US spend adds a further \$400 million annually. This brings our re-based 2009 guidance to \$7 billion.

To that figure we have added \$ 600 million per annum of investment in our EXCO assets.

In Australia we have expanded the scale of the business, increasing the capacity of our LNG plant and raising investment across the gas supply chain.

Phase III of Karachaganak has also been re-phased leading to a \$1bn reduction in this timeframe – around \$300 million per year.

Adjusting for all of these factors and a small underlying increase, gives capex at an average rate of \$8 billion for the next three years.

I'd like to turn now to the dividend and balance sheet. The Group ended the year with book gearing of 17%.

Our gross debt was £3.8 billion of which £3.1 billion is longer term debt, including ship leases with a term of 15-20 years. Our cash holding at year end was £700 million and in addition we have committed credit facilities of \$2.5 billion.

The Group's financial position and its strong prospects allow us to increase the dividend and the Board has recommended a 10% increase in the full year dividend to 12.35 pence per share. This is equivalent to 19.63 US cents which will be the base for setting future dividends. Going forward, our policy will continue to be one of providing dividend growth in line with long-term earnings growth.

So, to summarise and conclude:

- The Group has delivered solid profits and cash flow;
- Following a period of consolidation in 2009 and 2010, our E&P business is set to grow very strongly out to 2020;
- Our LNG business is set to produce material, stable profits for the foreseeable future; and
- Our balance sheet and strong prospects allow us to recommend a 10% increase in the dividend.

Thank you Ladies and Gentlemen; that concludes my comments so I'll hand you back to Frank.

Frank Chapman, Chief Executive Officer

Thank you Ashley.

I want now to begin by looking at BG Group's strong track record of growth: how that's driven profits and value; and how we plan to extend that pattern.

This chart shows the growth in our upstream production since 1997 – a 290 percent increase, equivalent to a compound growth rate of some 12 percent per annum.

Looking forwards, we expect that trajectory to continue to rise right out to 2020, meeting our growth goal of 6 to 8 percent per annum averaged over the decade.

And it's a similar story in LNG, where our contracted volumes show a 570 percent increase since 2003, equivalent to a compound growth rate of 37 percent per annum.

Again, in LNG, we anticipate that this rising trajectory will continue, so that by the middle of the decade our contracted volumes will have grown a further 57 percent to 20 million tonnes per annum.

This strong growth in our underlying businesses has produced a powerfully rising operating profit profile.

And this has been matched by strong shareholder returns, with the stock price rising by more than 400 percent since the second demerger in 2000.

So, over the last decade, high rates of growth driving strong share price performance.

Over the next decade, our aim is continued high rates of growth and a similar pattern of shareholder value-creation.

Let me now turn to our strategy, including how we see prospects for gas markets.

The investment proposition we offer is straightforward. We are an integrated, internationally diversified energy company, that aims to deliver rates of growth that are a multiple of the industry average.

Our business strategy supporting that investment proposition is now familiar to most of you.

We identify high-value markets that provide opportunities for growth, and we find competitively priced resources to supply those markets.

We possess the skills throughout the gas value chain to capture the opportunities and deliver competitive cost metrics.

And our growth is not just about volumes per se – the focus is on delivering a rising earnings trajectory that becomes the principal driver of shareholder value.

So, how do we see the context in which this strategy will be played-out?

As Ashley mentioned, 2009 was characterised by weak demand. We expect this pattern to continue into – and possibly through – 2010, as economic recovery begins to take hold at varying rates from country to country.

However, our view is that the present mismatch between supply and demand is temporary, and that economic recovery will rebalance the market.

Meanwhile, as Ashley has explained, we continue to lock-in value, where possible, to safeguard short-term trading performance.

In the medium term, we expect that gas demand will resume its growth pattern, driven by its abundance, economics and by climate change imperatives.

Copenhagen has underscored again that governments need credible and practicable policies to meet national energy requirements – while simultaneously achieving a significant reduction in carbon emissions.

We believe natural gas will prove to be a vital component of that journey to a lower-carbon future.

So let's move on now to consider the portfolio and the plans that have been built around our strategy.

Over the last four years, we have significantly strengthened and rebalanced our portfolio, giving us greater confidence in our ability to create value from a broad range of regional and global markets.

Our markets extend from the fast-growing economies in South America, India and China to established OECD gas markets in the US, the UK and the Pacific Rim.

Meanwhile, our material resource positions have been built up across an attractive balance of investment settings in both the developed world and within developing economies.

I want now to take a closer look at this portfolio, focusing especially on key developments within a number of our core assets.

I'll not be covering all of our assets in the presentation, and other areas of progress are covered in the appendix to your handouts.

Let's begin with Brazil.

Whereas the market recognises broadly the importance of Brazil to BG Group, the value we've already created from the Santos Basin is not yet fully recognised.

In particular, the rapid play de-risking and our concrete plans for early production ramp-up have already substantially increased the value of this play.

And, in 2009, our programme really stepped up a gear:

- we shot more than 3 thousand square kilometres of 3D seismic;
- we drilled 7 successful wells;
- we cored 275 metres of reservoir;
- we performed 5 Drill Stem Tests;
- and we produced 3 point 5 million barrels gross from the first Extended Well Test.

This programme has provided a mass of new information, advancing substantially our understanding of the Santos Basin, and supporting our earlier assessments and forward development plans.

As a consequence, confidence has increased in our early reserves and resources estimate of more than 3 billion boe net to BG Group.

Confidence has increased, too, in our ability to produce the oil and gas efficiently and economically, having now tested the technology and observed the excellent reservoir characteristics across a number of locations.

This is good news for costs and economics, and validates our view that BG Group's developments are economically viable at prices below \$40 a barrel.

PAUSE

Let's have a closer look at the significant progress, beginning with Tupi-Iracema.

Since last February, we've obtained a significant amount of new information on this enormous reservoir that extends over more than 12 hundred square kilometres, and contains some 5 to 8 billion boe of reserves and resources.

The Tupi North East and Iracema wells confirmed reservoir and hydrocarbon presence 16 kilometres and then 33 kilometres from the Tupi discovery well.

Both showed excellent reservoir characteristics, with outstanding initial production potential at Iracema of up to 50 thousand barrels a day per well.

The performance of Tupi Sul during the Extended Well Test also exceeded expectations, flowing at around 20 thousand barrels per day, constrained by facilities.

Importantly, pressure support is greater than expected after the production of more than 3.5 million barrels, with data also indicating an exceptionally large volume of producible oil connected to the well.

Now, this demonstrates very good lateral reservoir continuity and quality, which is further confirmed by preliminary pressure observations in the Tupi P1 development well, some 4 kilometres from Tupi Sul.

This information suggests higher recovery factors, lower well count and lower capex – none of which has been incorporated into the reserves, plans and economics presented today; as analysis of this data continues.

The bottom line is, we appear to be dealing here with excellent, productive reservoirs.

The Extended Well Test programme will move to Tupi North East later this year.

In terms of permanent facilities, the FPSO for the first phase of Tupi is now around two thirds complete. It will have the capacity to process 100 thousand barrels of oil and 175 million cubic feet of gas per day. We expect first oil around the turn of the year.

In parallel, we're working on the development plans for the currently testing Tupi North East and for Iracema. These will be the next phases in the Tupi-Iracema development.

We expect these developments to utilise 120 thousand barrels a day FPSOs, with the first targeted to come on stream by 2013.

So, the early appraisal and development pattern is now being established: exploration and appraisal; Drill Stem Tests; then Extended Well Tests, followed by the installation of permanent FPSOs.

For the full field development, we expect there will be up to 10 of these FPSOs on Tupi-Iracema.

And, we'll drill some 200 to 300 producer and injection wells, consuming around half of the development capex. Drilling performance has been steadily improving and the partnership is now establishing drilling improvement programmes aimed at deploying new technologies and methods to optimise our drilling investment.

Productivity tests on Guarà also showed excellent reservoir characteristics, with outstanding initial production potential of up to 50 thousand barrels a day per well.

The reserves and resources range of 1.1 to 2 billion boe is well ahead of initial estimates and will be more closely defined on completion by mid-year of the Guarà Norte appraisal well.

A five-month Extended Well Test of Guarà will commence later in 2010.

The development of Guarà will follow Tupi Sul and utilise an FPSO with capacity of 120 thousand barrels of oil and 175 million cubic feet of gas per day.

We recently signed a letter of intent for this FPSO construction, and first production is expected early in 2013.

On Iara, with its 3 to 4 billion boe of reserves and resources, we re-entered the discovery well to conduct a Drill Stem Test across multiple horizons.

However, down-hole operational difficulties prevented test objectives being achieved.

A new well will be drilled in 2010, and a Drill Stem Test will be conducted in 2011.

We will also conduct a 3D seismic campaign on Iara in 2010 and 2011, and plan an Extended Well Test, commencing in 2013.

Similarly, on Carioca we plan to spud a further appraisal well in the north-east of the field this year and commence an Extended Well Test at year-end.

Now, the pre-salt is generally thought of as an oil play.

However, it's also an important gas play.

These are material gas resources adjacent to a large and developing gas market, where we are present through our Comgas interests.

New infrastructure and commercial arrangements will be needed to bring this gas to market. And we may expand our market options further by developing floating LNG, which is the subject of parallel FEED studies.

We expect the Santos Basin to account for more than 400 thousand boe per day, net to BG Group, by the end of the decade, driven by a net investment of some \$20 billion in this play.

So, to summarise:

- we have created a great deal of value in Brazil which in our view is not yet fully recognised;
- the play is rapidly being de-risked;
- confidence has increased on the huge reserves base;
- we have seen excellent, productive reservoirs; and
- we have tested the technology.

But most importantly, I want to emphasise that Brazil is not just about 2020.

It is in fact a story about *today*, a story of exceptionally rapid progression from exploration to commercialisation; from concept to revenue stream.

It is a story about *current* production, and new, impending developments that will drive a strong production ramp-up in the first half of the decade, on a path to more than 400 thousand boe per day, net to BG Group, by 2020.

I hope the additional information we have given today will support an improved understanding of Brazil's significance to BG Group.

Now to LNG. To begin, it's worth reminding ourselves of the key components of our LNG business and the role LNG plays in BG Group's global gas strategy:

- we have a suite of cost-advantaged LNG assets around the world;
- we have global shipping and marketing capabilities;
- we have an in-depth understanding of our target markets;
- and we have an array of long-term and short-term customer relationships – BG Group has already supplied customers in 21 out of 22 LNG markets.

Taken together, these attributes amount to a somewhat unique, material and, we believe, sustainable LNG business proposition.

That proposition was further strengthened in 2009 with the addition of China – a new and very important long-term market for BG Group.

We also commissioned new regasification capacity in Wales and in Chile – an important counter-seasonal market with growing energy needs.

And we progressed our liquefaction plans in Australia, as well as introducing the possibility of LNG exports from Brazil.

But at *this* stage in the evolution of our LNG story, the *jewel* in the crown is undoubtedly Australia.

Just two years after our entry into Australia, we're now well on the way to realising a material new source of equity LNG.

This is a venture controlled by BG Group; located within the attractive Australian investment setting; and on the doorstep of the world's largest LNG markets, in the Asia-Pacific region.

Initially, QCLNG will be a two-train LNG plant, with nameplate capacity now increased to 8.5 million tonnes of LNG a year and coming onstream from 2014.

There is also space for future expansion on our site.

The project is already underpinned by our agreements with China, Chile and Singapore totalling up to 8.3 million tonnes per annum; outcomes from a highly successful marketing campaign.

QCLNG will be fed by our low-cost coal seam gas resources.

The acquisition of QGC in 2008 and Pure in 2009 has given us 120 thousand square kilometres of licences.

QGC's total discovered reserves and resources now amount to some 17.3 trillion cubic feet, around 2.9 billion boe.

Of this, some 12.6 tcf is available from the Surat basin to supply the QCLNG project on Curtis Island.

2009 saw excellent progress in Australia. Upstream appraisal, field development planning, engineering and procurement activities all gained significant momentum.

Upstream development will comprise around 18 hundred wells by the end of 2014, rising to more than more than 6 thousand wells over the life of the two trains.

Gas will be brought to QCLNG by a 340 kilometre trunk-line. Good progress was seen in 2009 with land access agreements and tenders for pipeline materials supply and construction.

We've also made excellent progress with the LNG plant FEED, and I'm pleased to announce that we have today signed the plant EPC contract with Bechtel.

Bechtel will be manning-up for the engineering and to progress procurement, under an initial notice to proceed.

The final notice to proceed will be issued following receipt of environmental and regulatory approvals, expected later this year.

Upstream, work continues on the FEED studies and cost estimates. We expect the competitiveness of these upstream assets to be confirmed on completion of the current FEED studies.

Meanwhile, the plant EPC contract positions BG Group at the low end of the unit cost curve, when benchmarked against contemporary projects.

In fact, as this chart shows, we expect economic break-even to be less than \$30 per boe.

Capital efficiency, or P over I, is estimated by BG Group to rise to as much as 2.9 at an oil price of \$110 a barrel.

So, some food for thought here.

Our QGC business will drive substantial LNG and E&P volume growth in the first half of the decade.

We anticipate net plateau production of 225 thousand boe per day.

And, of course, there's the possibility of material upside beyond this, with further Surat potential, prospective acreage in the Bowen basin and the potential for expansion at QCLNG.

In Australia, as in Brazil, 2009 was a year of substantial, positive developments which have significantly de-risked this new material venture, and put it firmly on a track to sanction later this year.

Now, one of the reasons we entered Australia is our belief that unconventional gas is poised to play a significant role in global energy markets in the future.

That same belief led us to explore the possibilities of shale gas, culminating last year in our alliance with EXCO in the US.

We're very optimistic about this new unconventional gas opportunity. US shale gas has the potential to transform supply to the world's largest gas market.

Shale gas resources are huge, but the quality of shale varies widely. Economic success will depend on owning assets of the *highest* quality, which can be developed at the lowest cost.

Our excellent Haynesville position meets these criteria; rich in hydrocarbons, and positioned at the low end of the cost curve.

Moreover, the EXCO alliance was a counter-cyclical investment by BG Group, allowing entry at a competitive cost and with a skilled and fully aligned partner.

And since acquisition we've been very active with EXCO, building on our core-area Haynesville position through acreage acquisition.

The alliance has also added mid-stream interests with access to markets in the southern and eastern states, which will complement our existing US gas marketing operations.

EXCO's performance and the quality of our acreage are amply demonstrated by this chart.

This shows how we continue to achieve excellent initial production rates for shale – between 20 and 30 million cubic feet per day – across a suite of wells.

We'll be operating 16 rigs this year – double the number since we announced the EXCO alliance last year.

During this period, we've seen drilling times falling progressively, having now halved over the first 30 wells.

Our net reserves and resources now stand at some 3.2 trillion cubic feet – more than 500 million boe; resources acquired at a cost of some 38 cents per thousand cubic feet.

And we believe there is further potential in our existing licences and more opportunities to grow that position.

As you'll see from this slide, we expect shale gas production to ramp-up steeply, to more than 600 million cubic feet per day – around 100 thousand boe per day, net to BG Group – as we approach the middle of the decade.

In terms of economics, we expect economic break-even to be \$3 per million btus.

Capital efficiency is again very strong, and rises to as much as 2.7, at a gas price of \$9 per million btus.

I hope you'll agree that this positive picture validates our view that competitively priced shale gas, embedded within the huge US gas market, represents a material opportunity for our company.

I would now like to turn briefly to other material assets within our portfolio, beginning with Karachaganak.

Over the last 12 years, we and our partners have invested almost \$10 billion in Karachaganak.

The latest such investment is in the fourth train of stabilisation, due onstream next year, which will enable in aggregate 10.3 million tonnes per annum of crude oil to be treated to export specification.

Although Karachaganak has been in production for many years, only around 7 percent of the hydrocarbons in place have been produced to date. The focus therefore continues on future development phases.

In 2009, we have been reviewing our Phase 3 development plans. Partners have aligned around a new multi-stage Phase 3, which yields improvements in manpower profile and cost phasing; and delivers improved economics for investors and government alike.

We're in discussions with the government to agree the shape and timing of this programme.

In the UK, in 2009 we assumed operatorship of the Everest and Lomond fields, where we are the majority owner.

This was part of an asset swap with BP, that concentrated our position in the Central North Sea and consolidated our UK upstream activities in Aberdeen.

In 2009, net production from the North Sea amounted to some 56 million barrels oil equivalent.

Projects to maintain that level were progressed, with Jasmine moving towards production in 2012.

We've also established a provisional first production date of 2015 for Jackdaw, with an appraisal well planned for this year.

Our aim is to maintain UK production above 50 million barrels oil equivalent per annum. In each of the last six years, we've succeeded in extending that plateau.

So we continue to make good progress in the North Sea.

In Norway, we're progressing development of our Pi, Bream, and Jordbær discoveries – the last of these being a successful new play concept, which could extend across a number of analogous exploration prospects.

And we're currently drilling Mandarin, our largest prospect, in which we hold a 96 percent interest.

Overall, we continue to extend the value proposition in Norway.

Now to our progress in exploration and appraisal.

In 2009, our drilling programme was focused on appraisal and commercialisation.

We drilled 28 conventional wells, yielding 17 successes in 2009, with a number of wells still under evaluation at year-end.

In addition we drilled around 200 unconventional wells.

In 2010, our focus will remain on appraisal and commercialisation.

We plan to drill up to 9 appraisal wells on Tupi-Iracema, Guarà, Iara and Carioca. And as I mentioned, we'll also further appraise the Jackdaw discovery in the UK.

In exploration, we'll continue work on Mandarin in Norway, and on Blåbær in the same play as the Jordbær discovery.

We'll drill the Macunaima exploration prospect on BMS-10 offshore Brazil, and we anticipate spudding the first of two wells offshore China towards the end of the year.

Let's turn now to our reserves and resources.

Last year, reserves and resources grew by some 1.4 billion barrels oil equivalent, bringing our total resources to an estimated 14.5 billion barrels oil equivalent.

This represents an increase of 10 percent over last year, and yields a reserves and resources to production life of around 62 years.

Discovered Resources – previously called 'Unbooked Resources' – are up by 32 percent, to 4.9 billion boe since last year.

Finally we have the exploration prospect inventory. This has reduced to 3.4 billion boe, reflecting the drilling out of some of the portfolio, with successes moving down into one of the discovered categories below.

So the track record from 2005 is a positive one. Our total reserves and risked resources stack has more or less doubled, by 7 billion boe, in just 4 years – equivalent to a compound growth rate of some 20 percent per annum.

So, these are the reserves and resources that underpin the growth trajectory that I outlined earlier.

And this is the shape of that trajectory, derived from our long-term plans.

This plan shows the contribution from Brazil, Australia and our other assets, and the rapid growth we plan to deliver as we move through this next phase.

Overall this plan sees BG Group achieving growth at the upper end of the target 6 to 8 percent range by the end of the period.

It shows also that BG Group will pass through the million barrels a day threshold by around the middle of the decade.

Now, one important point to emphasise is that we don't need to add assets to our portfolio to achieve this outcome.

The portfolio already contains *discovered* reserves and resources sufficient to exceed the lower end of the target range, with higher growth rates achievable from the risked exploration prospect inventory that we already own today.

So, to conclude with our key points.

- We've announced resilient results for 2009, against a backdrop of a challenging economic environment.
- We've shown upstream growth to 2020 at the upper end of our 6 to 8 percent per annum target range, and progress towards our 20 million tonnes per annum LNG goal for 2015.
- We've shown excellent progress in Brazil, and how we're on course to produce more than 400 thousand boe per day by 2020.
- We've also shown excellent progress towards sanction of the QCLNG project, and how we're on course for net plateau production of 225 thousand boe per day.
- And we've shown excellent progress with EXCO, and how we're on course to produce around 100 thousand boe per day by 2015.
- We've disclosed new guidance of \$1.8 to 2 billion per annum for LNG profits in the years to 2012.
- And, finally, we've increased reserves and resources by around 1.4 billion boe, giving a total of 14.5 billion boe – sufficient resource to underpin our growth ambitions.

So I hope with all of this, you share our view that we have an exciting future in prospect.

BG Group is entering a new decade of high growth.

And our confidence in delivering that growth flows from:

- our strengthened and rebalanced portfolio;
- our key projects, that are being rapidly de-risked;
- and our reserves and resources base, which is sufficient to underpin our ambitions.

And with these foundations, BG Group has the potential to extend our track record of growth and shareholder value creation deep into the future.

Thank you for your attention, and now Ashley and I will be happy to take your questions.

Q & A session

Iain Reid, Macquarie:

Hi Frank, Ashley, can I ask three things please? Firstly in Queensland Curtis LNG you've got 17 tcf of resources now which must be fairly close to having the resources for three trains and I think you've got approval in your EIS statement or you're seeking approval in the EIS statement for three trains. Is it going to be a priority to prove up the reserves for that or are you basically focusing on the one you've got and then kind of let that happen naturally if you like?

And secondly on Karachaganak you talked about political risk and it seems to be an area where political risk is rising, or at least commercial risk, from what we read about in the press. Is there any kind of challenge or problem there which might perhaps push you off your ambitions for Phase III and maybe you could talk about that a little bit?

And thirdly you shared those PI charts for Australia and US gas could you possibly tell us where Brazil would sit at say a \$70 oil price on the same basis? Thanks.

Frank Chapman:

QCLNG - at the moment we've got - we've identified around 12.6, 12.7 tcf of Surat Basin reserves and resources for feeding the two trains. We've also got some - I want to say 1, 1.3 tcf of domestic obligations, contracts there. And then we've got further resources around 3.5 tcf or thereabouts in the Bowan Basin.

Our effort at the moment, of course, will be to focus our development in the Surat Basin so that we can do that efficiently and launch the first two trains based on that. And this year I believe we're going to drill something like - I want to say 37 wells, if our director of exploration is in the room he might correct me if that's wrong, exploration wells in some more of our - 120,000 square kilometres of acreage.

So we are working to prove up more reserves and in time that will support, we believe, a further train of LNG. For the moment the focus is on drilling up and proving up reserves for the first two trains. And by the way, we're ahead of schedule on that. So I think by the end of last year we were already over 5 tcf and you know moving at quite a pace. So I expect that number to be running some 20% ahead of our plans for proving up reserves.

So that's going really well, very positive, very ambitious to make more of our QCLNG project. Of course if I may just go on we all know that to make a successful LNG project you need reserves, we got those. You need customers; we've done a terrific job in pulling together that level of demand up to 8.3 million tonnes in this environment, under commercially favourable conditions. I am very, very pleased with the way the team has done that.

We've got the capital and this will be the seventh train that we've built, so we know how to do it. All the pieces are there; this is going to happen - very, very positive about that. Do you want to talk about Karachaganak?

Ashley Almanza:

We're obviously in close discussions with the Republic at the moment and the discussions focus on two things. First, I think it's well known that there's a dispute over export customs duties and the consortium, all partners in the consortium are sitting down with the Republic to see if we can find a solution to that, a negotiated solution to that. There is, I think, goodwill on both sides to try and find a solution. But we won't know until we get there.

That's relevant to the second subject that we're discussing, which is Phase III. The partners would all like to clear up the dispute in advance of moving to Phase III sanction. We've aligned around a development concept for Phase III, the partners, and we've presented that to the Republic and we're in discussions with them over that concept.

I think again there's a will on both sides to make that project move forward. So I would hope that before too long over the course of the year we can move from development concept into FEED studies.

Iain Reid, Macquarie: But is it true to say - sorry Ashley, is it true to say that if you don't get resolution over the custom duties you won't go ahead with Phase III?

Frank Chapman: Well we can't conduct the negotiations in open forum. I mean clearly there are some issues which we want to get sorted out. The government wants to get clear on the precise shape of Phase III and this is, you know, a discussion we're having as grown up individuals in closed forums. So that's just going on, that's just a part of business life.

But without wanting to repeat too much, the Kazakhs have done a great job. You look at the way Kazakhstan has progressed relative to other former Soviet states they've done a terrific job and one of the elements of that success is the open declaration of fiscal stability; such that foreign and direct investors bringing that money can operate with a sense of stability.

Now, Kazakhstan is not finished with its development, it wants to do a lot more and it has to attract the capital investment in an environment where there are more challenges than there were some years ago. I mean right now there are more challenges.

So we'll see what they do, but I think they will be looking at how they've succeeded in the past and they'll be looking to see what foreign investors want in the future in order to bring their money and bring their skills. Sorry Ashley.

Ashley Almanza: That's all right, good answer.

Laughter

Iain Reid, Macquarie: And on the Brazil PI number?

Frank Chapman: Yeah, Brazil PI I mean I guess I wouldn't expect it to be that much different from our Australian business. Except of course for those more prolific areas where I'd expect it to actually be significantly stronger. And of course those are the very areas that we're going to be focusing on first. But right at this moment it's difficult to say more, I'm sorry but I can't really take that any further.

Michael Alsford,
Nomura:

Good afternoon, two questions please, firstly on Brazil, could you maybe remind us what recovery rates you're assuming for your reserve and resources estimates for the likes of Tupi, Iara and Guar and where, given obviously the positive technical data you're picking up from there, where you might see that moving to?

And secondly on production, could you maybe help quantify the impact that you saw in 2009 from the weak gas demand across the portfolio and what you're assuming in 2010 in your sort of small growth for 2010? Thanks.

Ashley Almanza: On gas demand, we saw demand affected in a number of markets, principally Kazakhstan, Russia, Thailand, Bolivia, Brazil, Trinidad, those were the main markets where we sell gas that we saw demand effects and in total we estimate that cost us about 10 million barrels.

The picture for 2010, as I mentioned, we see that picture continuing through 2010. So broadly the same amount this year.

Frank Chapman: Recovery factors, we've not been disclosing recovery factors and we're not quite ready to do that. As I said in my remarks, the very positive data that we've received from drill stem tests, production testing, would suggest higher recovery

factors, lower well count, lower capex is what I said in my remarks. But you know there is a huge amount of new data and a huge amount of analysis going on to look at vertical and horizontal - lateral connectivity and quality. And we'll be doing quite a bit more testing before come out and go nap on what we think recovery rates are going to be.

But rest assured it's exciting days, a lot of new information, a lot of great work going on.

Theepan Jothlingham,
Morgan Stanley:

Good afternoon gents, two questions actually. Just coming back to EXCO, I was wondering how do you see the pace of development at EXCO and given commodity price assumptions - I know you've given a sort of range of three to nine, if you're at the low end and Henry Hub sort of stays at that type of price do you actually see the 100,000 barrels per day sort of perhaps pushed back? And if you could talk about US gas in that sort of context?

Secondly, not sure whether you'll answer this question or not, but on LNG and Curtis could you perhaps tell us where you think the current cost curve is?

Frank Chapman:

On Queensland Curtis, I'm happy to give you the P over I curve which will show you. I mean you know that any project that's producing a P over I over 1.3, 1.4 you know it's a soundly economic project, by inspection that would generally be the sort of conclusion you would derive from that. Something over two is a terrific project, something that gets at the higher end of prices, 2.7 that's a very good project, that is an excellent project. So that's all I'm prepared to say on that.

We are doing the FEED study for the upstream, when that's finished we'll give you the whole capex because we'll have the whole story and we'll give it to you at that point. For the moment I'm quite happy to keep our capex figures close to our chest. But I am completely comfortable on the economics of this venture and on its competitiveness with conventional resources. It's going to be out of the blocks, it's going to be an unconventional driven LNG project and it's going to be soundly economic.

US gas I've given this story before and most people seem to follow this story and it's the one that goes around that says, you know whatever number you want to choose, 10%, 15%, 20% per annum decline rates, whichever number you want to choose in a 60 bcf a day market, if you chose a 20% decline you've got to find 12 bcf a day supply, every year you've got to do that. The most LNG that's ever gone into that market is about 4 bcf a day. So you can't fix the US decline problem with the current picture of LNG supplementation or importation.

The solution in the US is going to require the development of shale gas; there is no doubt about that. As I also mentioned in my remarks, the key to succeeding economically with shale gas is to have the right quality. That means the right hydrocarbon content, the right quality rocks that can produce gas at the low end of the cost curve. If you can get the very low end, be the lowest cost operator. That's what we're trying to do. And then the gas price in the market which has to justify the development of the project which balances supply and demand. The low cost projects get to enjoy the difference in the long run marginal cost of your project and the long run marginal cost of that project which just balances supply and demand.

Now because the US gas market - no gas market is that rational in that all the low cost stuff gets developed first and the more expensive stuff later; so you get a mixture of this stuff happening. And the more expensive stuff will fix the US gas price. So the key to success is low cost, be the low cost operator and then you get to enjoy the margin.

Our breakeven, economic breakeven as I've said is \$3 a million btu, currently today in the depth of a recession we've got \$5.50 or thereabouts, you will know because

you came in just recently, I've been here all day and I haven't looked at the monitors.

So that's really the theory, very simple, a very simple approach to the way we see gas prices in the US. Was that it, did I get your question, was that it?

Theepan Jothlingham,
Morgan Stanley:

Yeah pretty much, just as a follow up do you think the resource base you've got today with the EXCO position is it enough to deliver that 100,000 barrels?

Frank Chapman:

Yeah definitely, absolutely. That's what that chart shows, it shows what we've got in the Haynesville and then it shows some other potential, as horizontal drilling in tight sands and Bossier shale and we've got - you know in the time since we took this alliance we've added to our - I want to say 45 or 46,000 net acres of really core Haynesville stuff. We've added another 14,000 in that time. So quite a bit of a step-up and these are really rich, core positions. And we've acquired this addition stuff at lower than the average cost per mcf that we acquired - you know made the original acquisition. That was 37 cents and I think we were down at 30 cent average for these additional volumes we've added.

So a lot of potential there, very excited about that. We set out to make this a billion barrel play as a minimum. We're already more than half way there and we've only just started.

Irene Himona,
Exane:

A question on your LNG guidance and thank you for giving us the visibility of three years ahead. I'm just trying to understand how your view of margins and volumes may have shifted since last year. Simplistically looking at it your - of course it is Henry Hub, your sales price is oil. Last year your scenario was \$50 oil and \$7.25 and you guided to £1.2 billion for 2010. This year your reference oil goes up to \$70, gas down to \$7. So on the face of it margin has improved, the guidance remains similar. Can you explain how I can bridge one with the other please?

Ashley Almanza:

I think the very simple answer which is the reference conditions are simply a way of us aggregating up our plan across a common set of exchange rates and prices and they don't really reflect the economic prices in the market. And when we gave the guidance last year, I think we were quite clear to say that actually the guidance didn't vary that much across a range of prices. So that's the short answer.

Frank Chapman:

Yeah, I think we said that we didn't expect the result to change very much with Henry Hub prices changing between \$4 and \$7 a million btu.

Christine Tiscareno,
Standard & Poor's:

Three short questions, the first could you tell us in all the targets that you've been giving us, what kind of assumptions do you have in terms of gas and demand prices for natural gas, sorry, being down for about three years, five years - what sort of down time do you put into your estimates?

And then the second, could you give us an idea of what type of LNG price do you need in order for Queensland to be profitable? And lastly could you give us your opinion as to how the development of global, not the US, global shale gas could affect your LNG growth plans. Not so much in terms of volumes but financially as a large - well not a large part but a more significant part of the contracts start going towards short term?

Frank Chapman:

QC LNG economic breakeven \$29 a barrel, that was on the P over I chart, actually it was ...

Ashley Almanza:

That's economic breakeven.

Frank Chapman:

That's economic breakeven ...

- Christine Tiscareno,
Standard & Poor's: What LNG price?
- Frank Chapman: Well our LNG out of QCLNG is all sold essentially and it's sold into three markets, we may choose to redirect that with the flexible portfolio we've got. But under the assumptions we've made in terms of this gas going to Asia Pacific oil indexed markets the economic breakeven, it's a good number is less than \$30 a barrel, I think it's \$29.50 or it might be \$28.50, I can't remember.
- On what prices do we need to make these projects economic well that's that one. I think we said it was \$3 a million btu for the US. Essentially the projects that we're talking about in the future are all economic at today's prices when we're down in a pretty tough weak market position. So as we go forward if we maintain the prices that we had today these projects would all be - you know comfortably economic.
- Ashley Almanza: There were two, you asked about the assumption on demand in the plans ...
- Christine Tiscareno,
Standard & Poor's: Really all the targets that you've given us - I mean at the moment we have depressed demand in natural gas prices. And some people are saying this is going to last for about two years, some are saying four years, five years, what are your assumptions in order for you to meet those targets?
- Ashley Almanza: The assumption that I referred to when I was talking about 2009 and 2010 that we are making is that the weak demand will persist through 2010 and we'll see gradual recovery in 2011 and then resumption of growth in 2012. That's our overall assumption.
- You should bear in mind though that much of what you've seen today is either - well includes oil and liquid projects and also some contract off-take arrangements. So as we rollout it's not only gas demand that you have to keep in mind.
- Frank Chapman: Remember as well that for the QCLNG project, this gas is sold and there are take-or-pay requirements associated with that gas volume. In the US the whole idea there is - being in this large liquid fungible market - the whole concept there is to be the lowest - to strive to be the lowest producer. And with a break-even price, economic break-even at \$3 a barrel, we're feeling pretty good about that.
- Christine Tiscareno,
Standard & Poors: Okay, but would it be safe then to assume that if the period of depressed natural gas prices on demand extends beyond 2010 to 2011, that then your targets will also have to move accordingly - or that you'll renegotiate?
- Frank Chapman: No, I don't think so, because what we're saying here is that - today in the US we are beefing up the programme, we're pulling in more rigs, we're drilling more wells. We're going to bring a lot of wells on this year. That you know, this is possible today - even where we are today. So if the situation we're in today persists, this is fine; we will still get to these numbers. And with QCLNG the gas is already sold, so when that comes on, that gas has got customers to go to.
- Frank Chapman: You asked about the impact of shale gas on our LNG profitability, if I understood your question?
- Christine Tiscareno,
Standard & Poors: Local development, not the US.
- Frank Chapman: So I think that clearly over the next three years this is not going to have much effect because 80% of our LNG profitability that we showed is firm now because of the arrangements we've got in place around terming our sales and locking in

margins, and also because the liquefaction component doesn't vary much with price.

Beyond that I think it's important to keep in mind that we buy a lot of our LNG on a Henry Hub index, so when - if in the scenario I think you were pointing to - shale gas brings average gas prices down in the United States, well then in principle - depending on what's happening to oil, but if you keep everything else constant - our margin increases rather than decreases.

Ashley Almanza: Margin on LNG.

Lucas Herrmann, Deutsche Bank: Thanks, Frank. Actually a few questions, if I might. Firstly, Ashley, you're a very competent man, but you're doing an awful lot at the moment. What's happening as regards your dual capacity? When's it going to be sorted out, particularly the number of projects in front of you?

Secondly, I know pinpointing things through the year is not easy, but your record over the past year in terms of guidance has been about as poor as mine, and I'm not terribly happy probably with the way things have gone for me. But you know, Q1 - continuing 680 for the rest of the year. Q2 - good line of sight on outlook for production. Q3 - production will average 700,000 barrels of day through the fourth quarter - I mean, they've all been woefully inaccurate. I guess the question is - the information coming up to you from below - are you confident in the systems? Are you confident in the guidance that you're actually getting around things at the present time?

And a third question, just going back to costs in Australia, your Chairman said at the start - investment in Australia towards 20 billion, you know, by the time things are finished. I'm presuming that that includes, you know, 5 billion or so of acquisition costs for Pure and whatever.

Frank Chapman: And it just includes, you know, out this decade. So we're going to go further than the 1800 wells to 2014.

Lucas Herrmann, Deutsche Bank: Right. And just whether you want to make any comment on hedging and EXCO, and whether you have hedged some of the forward production, and taken some of the risk out as most of your competitors or EXCO -

Frank Chapman: Let me have a go at the guidance thing. Quite basically we estimate that we lost 10 million barrels last year from weak demand situation in Bolivia, Brazil, Trinidad, Kazakhstan, Russia, Thailand - 10 million barrels. We lost 4 million barrels because of delays in Hasdrubal. Now, you know, we made the mistake, I guess, of assuming in the fourth quarter that the market would recover as we entered this seasonally higher demand situation. That didn't happen. So, you know, we didn't make it.

I suppose, you know, we have to be realistic here. We're trying to deliver progress through what is the worst recession that any of us sitting in this room have ever seen, and we're not going to be - no matter how hard we try - immune to that. If we look at the long-term, in the past this company has grown massively production and LNG. When we look forward we are going to grow massively production in LNG and in Exploration and Production. And the projects that are going to drive that, which are Brazil, Australia, the US, the UK, a little later than planned - Kazakhstan; those projects - certainly the first four of them - are all really building momentum. So if, you know, when we end up in 2020 and we look back at almost 25 years of 10% per annum compound annual growth rate over almost 25 years average, then a blip in 2008 and 2009, as a consequent of the worst recession the globe has ever - I think - one of the worst - certainly the one we've witnessed - I don't think we'll look back on that and say - the company screwed up.

Lucas Herrmann, Yeah - what I'm asking you about is the information coming up that's

- Deutsche Bank: leading to you making statements that are not being delivered on?
- Frank Chapman: No. No, no. Listen, let me be very clear. I take responsibility for that. I take responsibility for that. I'm the one that's sitting there saying I believe that Russia is going to take more gas; I believe that Karachaganak will produce more gas. I believe that we can divert domestic demand into export demand. I'm the guy that's saying that. And I got it wrong.
- Ashley Almanza: Who's going to take a question on what I'm going to be doing ... ?
- Frank Chapman: Look, Ashley's appointed a deputy who's taking the load. Alistair Williams - he's taking the load during this period. Ashley is not going to do this dual role permanently, and it won't be very long before we make clear what the plans are in the future. But you should not assume that this is a permanent arrangement; it is an interim arrangement, and we will advise in due course how the sustainable set-up will shape.
- Lucas Herrmann,
Deutsche Bank: I'm sorry - any comments on hedging EXCO?
- Frank Chapman: Yeah, I think the only comments I'd make, Lucas, is that we look at our price exposure on a global basis rather than in a particular production area. So we have Henry Hub exposure from a number of locations and product streams - we look at the whole thing. So it wouldn't be appropriate for me to say we've allocated a hedge to EXCO specifically; it's changed our overall Henry Hub exposure, and we take that into account.
- Fred Lucas,
JP Morgan Cazenove: Thanks, Ashley. Two numbers-based questions. First of all, Frank, as it stands today, what is your upstream portfolio's perfect day output capacity? You've talked about that number in the past.
- Frank Chapman: You're saying the two to one in Australia - I said you'd replicate Australia - it wouldn't be so different. Yes, it wouldn't be so different.
- Fred Lucas,
JP Morgan Cazenove: So if we take two to one, and use the one project that you've put capex to, which is Tupi Sul - \$3.6 billion to recover 300 to 400 million barrels. I wonder if you could correct the maths, but that's leading to an NPV per barrel...
- Frank Chapman: You know, I can't say a great deal about this really, but what I would say is - when I made the comment earlier on to Iain, what I was simply saying was - if you take all of our - let me just say - if you take the full field development of Tupi, that contains more prolific areas and less prolific areas. So it represents really a sort of average for what we expect to come out of the whole of our 3 billion barrels oil equivalent developments in Brazil. So Tupi full field development - all of Tupi - is sort of representative, I reckon, of all of Brazil for BG.
- And what I'm saying is that - I was asked the question - what would it look like? And I said, well it wouldn't be so different from the Australia business. So that's the context I think you have to take that in.
- And you know, sweet spots in there, really prolific fields, I would expect them to do substantially better than that. That's all the guidance I can give you, gents; I'm sorry.
- Fred Lucas,
JP Morgan Cazenove: And the portfolio's perfect day capacity?

Frank Chapman: Yeah. 7 - 720, thereabouts -

Ashley Almanza: That's about right.

Hootan Yazhari,

Bank of America Merrill Lynch: Just a couple of questions. First of all, you guided that 80% of your LNG volumes have effectively been locked into an attractive margin, but you also mentioned that some of that is semi-flexible. If we were to see a continued diverging trend in oil and gas prices throughout the rest of 2010 and into 2011, is there scope for that LNG number to move up on the upper band?

Second question I have is regarding Brazil. I appreciate your hands are tied with the contractual agreements you have with Petrobras in terms of providing us with guidance, but it's very clear that you're guiding towards a much more effective capex programme against guidance that you've given previously. The guidance that you've given today is very similar to what you've been saying for a number of years now in terms of the development programme. When will you be in a position, do you think, after all this data is read, when do you think you'll be in a position to give us proper guidance on the number of FPSOs you're going to use, the flow rates that you really see coming through, and the like?

Frank Chapman: Well I think the flow rates that we're seeing coming through are - you know, we've been disclosing results from wells we've tested. I think that we're going to be doing a lot of work now in - we are doing a lot of work right now and that's going to continue. And I think it's prudent not to, at this point, suggest specifics in terms of recovery factors and the extent to which they're changed from the test results. But we're doing a lot of work on that, and I think that that will be a piece of information that we will have to agree with the partnership when we're ready to make any statements on.

Capex data - there is capex data out there. I mean, we - you know, other operators, other developments in deep water, the capex numbers are there. We have also disclosed for Tupi Sul a capex number of \$3.7 billion. I would remind you that that \$3.7 billion includes a chunk of capex for infrastructure development - we've got to get this gas to Mexilhão for evacuation, and the pipeline infrastructure that we're building is enough for three Tupi Suls, so Tupi Sul is carrying a disproportionately heavy burden in that \$3.7 billion for gas infrastructure.

But that will give you some clues. And you know, I think on that side you can get the CAPEX from what you know today. But look, the point is taken - the market would like some more information and we endeavour to provide the market with that information.

Ashley Almanza: We did also say in one of the slides that Frank presented around 10 FPSOs for the Tupi Iracema field.

Hootan Yazhari,
Bank of America
Merrill Lynch:

As far back as I can remember you've been saying between 5 to 10 FPSOs, but if you're looking at very high flow rates, a fewer number of wells to be attached to each FPSO and the like, it seems that you could reach your - either your peak production goes up above the million barrel top end range, or you're going to need fewer FPSOs, it would seem.

Frank Chapman: Well, you know, if you think about it - you know, the numbers are already out there. The fulfilled development of Tupi lies between five and eight billion barrels and we're going to do that with 10 FPSOs. You know, so that's what we reckon today, so you can work it out how much recovery there is per FPSO; it's pretty straightforward.

Look, I understand your desire. My desire would be to give you as much information as I possibly could. We're not quite ready to do that; the analysis goes on. But I can assure you that we will endeavour to give you the best guidance we can as the consortium comes to a landing on some of these parameters. And in the meantime I just have to ask for your patience.

Ashley Almanza:

LNG. Let me repeat what I said - 80% in each of the three years of the profit was firm. The semi-fixed portion that you refer to is the liquefaction. So we're not talking about 80% of only the shipping and marketing profit, we're talking about the whole segment, which includes 320, 350 million US dollars per annum of liquefaction tolling profits. And that is - that's the semi-fixed piece because it does fluctuate slightly. But I wouldn't expect over the period of the guidance to see much movement in that number.

Gordon Gray,
Collins Stewart:

Within your E&A programme from last year one of the key successes you mention was Abu Butabul in Oman. But Oman doesn't make it as far as even the appendix or as one of your core countries in your development map. You were very excited I think about the prospects in Oman when you talked to us a year ago. Can you tell us where it figures now?

Frank Chapman:

Two years ago I think Well we've drilled, I think, in our numbers we're carrying about five or six successful wells that we've drilled out there. We've drilled in total; I want to say we've drilled seven wells. One or two - I want to say one of those is still under evaluation. One was deep down flank and has not been a success and the rest of them have been successes. And you know we are in the process of agreeing with the government a development for Abu Butabul.

This will be a somewhat smaller development than we'd anticipated initially. The gas volumes are there. The question is economics and the question is recovery. It's a very tight reservoir, it is a tight gas reservoir but this is an area, as you will recognise, that BG is now getting quite interested in. And some of the technology that we're deploying for example in North America will be deployed in this play.

In time, the initial wells will be vertical wells but then we're looking at multi stage frac horizontal wells as an option in Oman. And we're very keen to make a success of Oman. So it's at this stage somewhat smaller than we'd anticipated in terms of recoverable reserves in this first phase. But the volumes of gas in place are very substantial so it will take a little longer to get there. But we're very keen. It's a very, very good place to work. It's a good investment environment and you know we'd like to make a success of it.

Colin Smith,
ICAP:

Three from me. Just sticking on the same line as Gordon had, you drilled three explorations or at least there were three discoveries announced in Brazil in 2009, and none of those seemed to make it into the key successes either and I wondered if you might just comment around about that?

Then sticking with Brazil I think you mentioned that net investment to BG would be some \$20 billion, I think through 2020. And I was just curious as to what your assumptions were about whether those - the FPSOs are all leased in that assumption or whether you're assuming that the partnership actually owns them and funds them?

And on a similar vein can you talk a little bit about how things might work with QCLNG and I'm thinking here that presumably the proven reserves is a relatively small number, a lot smaller than you would need to be able to absolutely guarantee proven reserve coverage for the plant itself. I may be wrong. I mean how will banks look at that if you come for funding? In other words will you be able to, would you seek to project finance that or is that something also that's going to have

- to be entirely equity funded until you've drilled up enough wells to prove to the banks that the gas is actually proven as opposed to in a 2P category?
- Frank Chapman: On the leasing versus owned FPSOs, nominally and this is still a subject which is under discussion, nominally the first three or four we're expecting to be leased. But our ambition is to get these FPSOs to be owned; you know capital goods by the consortium. So that's what we're trying to get to there.
- Colin Smith, ICAP: And is that in - what does the 20 billion actually assume then?
- Ashley Almanza: It assumes the first three are operating leases and then we move towards finance leases.
- Frank Chapman: Exactly. Proved reserves of course in coal seam plays are - the whole thing's very different. The way you carry reserves clearly, you've got a boundary a fair way, you're pretty much sure what's in there and you drill matrices out and you add reserves through matrix drilling essentially. So the whole process is quite a different one than proving reserves by finding a contact and so on.
- How the banks will I'm going to defer to Ashley on the bank side of it.
- Ashley Almanza: What we've assumed in the plan is that it's equity financed. Actually for presentational purposes, it won't make a difference because this is going to be virtually a wholly owned subsidiary. So whether it's project financed it will appear in the same place presentationally.
- As to whether or not there will be bank appetite, well some of you will know better than us. But from what we can tell at this stage there is certainly good interest, whether or not that represents ultimately a commercially satisfactory bargain for us we'll have to see. But the assumption for now is it's equity.
- I think banks will invest the effort to understand that the way reserves are booked in unconventional projects is by definition just different, and they'll look through that and understand that to get resource security behind the loan they'll have to apply a different methodology. But we'll see.
- Colin Smith, ICAP: And on the discoveries - that didn't make it into key successes in 2009?
- Frank Chapman: That was just presentational. I mean we carried those in our count. We made 17 successes last year and they're in the count. I don't think we listed all of them in my speech. That wasn't intended to be an exhaustive list of 17. I think there were three successes in Trinidad, for example, that I didn't list there.
- Oswald Clint, Sanford Bernstein: Just two quick ones please. Some of the other LNG projects in Australia are talking about the utilisation of the ramp up gas. I wonder in terms of re-injection or utility plants, I wonder if you could say what your plans are for the ramp-up gas of this project?
- And then just a little bit north, on exploration. There has been some interesting discoveries in the South China Sea where you are targeting a well by the end of the year. Could you just say if you're targeting similar structures to some of those wells perhaps announced by Husky recently? Thank you.
- Frank Chapman: The prospect that we'll be drilling - the first prospect we will be drilling is in an analogous play to the Husky play, it's one block removed. So Husky are there, we're one block removed from that on the same trend. So that's the same play there in the South China Sea.

Ramp gas, there are a variety of things that can be done there. For example, firstly you can drill your wells earlier and cycle your wells. So that's a possible component. The great thing about this coal seam play is that the coal seams sit between tight clastics formations such that when you dewater them they don't recharge with water. There's not an aquifer that comes back up again. So once they're dewatered they stay dry. So you can dewater a well, turn it off, go somewhere else and use your domestic demand to dewater a suite of wells. And you know then bring them on. That's one way of doing it.

Another thing that we're looking at, which is undergoing testing at the moment, is to use partially depleted coal seams. So when you dewater the wells and when you take some of the gas out the cleats open and the volume available in the matrix is far greater than when you started off. So when you recharge these reservoirs they can hold a lot more gas than originally came out of them. So using partially depleted seams, coal seams which are still in production today so you just curtail production and you just connect them to you know your main discharge header and let the gas seep back down. That's a possibility there.

And there are tight sandstone reservoir possibilities, you know conventional reservoir possibilities. And there are a series of commercial arrangements of gas swaps in time that also we're looking at. And we started a number of areas of work in this. A number of these strands of work and we have a combination of those that are aiming to deal with our ramp gas issue.

Lucas Herrmann,
Deutsche Bank:

What proportion of the reservoir does the comment on tight clastics apply to?

Frank Chapman:

I mean either side. I'm saying - the point I'm making there is that you have basically tight sandstones either side. You know you have a series of coal measures and I'm saying that outside the coal area, the coal zone you have tight sandstones. And these sandstones are sufficiently tight to prevent the ingress of water once you've dewatered the coal seams.

Lucas Herrmann,
Deutsche Bank:

Yes. Sorry I just wondered whether you could give any idea of what proportion of the acreage you're drilling you're actually able to switch on, switch off as a consequence of that phenomenon?

Frank Chapman:

Pretty much the whole lot. Still of course we haven't drilled everywhere so when I say that I'm giving you a view about what is expected rather than what is proved. But already there's been significant production in the Surat and the evidence is reasonably strong that once dewatered these coal measures do not recharge. So it's good news.

There are some areas where you get such an active aquifer underneath that as soon as you stop pumping the whole lot floods. In Surat, once we've dewatered the wells we take the pumps out and take them away and use them somewhere else. And the well produces for the rest of its life under free flow. The Surat is actually terrific coal. When you drill the well they actually carry out a drill stem test. The wells are so over saturated that they flow gas from day one. Okay. It's good stuff.

We're going to take one last question and we'll wrap it up.

Neil Morton,
MF Global:

Question on Brazil and I wanted to test your diplomatic skills in a public forum.

Frank Chapman:

Again?

Neil Morton,

MF Global: Could you perhaps give us your thoughts on the current Brazilian oil laws passing through the parliament, how the Brazilians are approaching it from your perspective. And just secondly if those laws pass unaltered and future pre-salt acreage is offered up, are those the kind of auctions that you would want to get involved in where the highest bidder wins?

Frank Chapman: Well although the shape of these new laws has been described, the elements - the fixing of some of the parameters in absolute terms has not been declared. And therefore the overall profitability of any given play or any given structure under the new terms is not very clear. What's going to actually be the set of terms that are bid and what are going to be the set of terms that are determined by the government has yet to be disclosed. So you know we will see. What will be, will be.

With regards to the government's approach, I mean it is reassuring that the government have been saying to BG and to other international investors we will honour the contracts that are already in place, these new laws will apply to new licensing rounds and not be made retroactive. And that is reassuring and that is a message that has been repeated a number of times over. So you know that's where we are.

Will new blocks be attractive for BG to invest in? Well that we'll take a judgement on when the licensing rounds come round. The acreages put on offer; we'll have a look at the prospectivity. If we like it we'll decide whether we want to bid. That's it really. I mean we have plenty to be going on with and that's where our efforts are focused today.

Neil Morton,
MF Global:

I just wondered also whether you thought that Petrobras was potentially running the risk of over extending itself, either from a financial capacity or a human resource capacity as - forced operating of all the fields?

Frank Chapman:

What I would say is that Petrobras has got obviously a very big capital programme. And I'm delighted to tell you, and I'm sure that Petrobras have said this already so I'm on quite safe ground here, that our projects feature amongst the most important projects in their portfolio. And they have declared very, very publicly and repeated that they are absolutely committed. And their behaviour to date has been consistent with that statement. They are getting on with it tremendously.

Thank you very much everyone for your attendance today and I look forward to seeing you - speaking with you in Q1. Thank you.