BG Group

2010 Fourth Quarter and Full Year Results and Annual Strategy Update

8 February 2011

Sir Robert Wilson, Chairman

Good afternoon ladies and gentlemen, I'm Robert Wilson the Chairman of BG Group and it's my pleasure to welcome you all here this afternoon to this Q4 Results Presentation and of course our Annual Results Presentation.

Now the format this afternoon is going to be just a little bit different from what you usually see. Normally we have Frank and Ashley making this presentation between them. This year it's going to be a little different because we're having Martin Houston talk to you as well about what's going on in the global gas markets.

And the reason for this is that there's been quite a lot of confusion amongst parts of the investment community about what is going on in gas markets during the last year or so. Even today we're looking at gas prices in the United States which are about one quarter of their energy equivalent oil price - one quarter of the price, which seems a bit surprising on the face of it at a time when gas is regarded as a clean fuel and a premium fuel, so why is this happening? And there is also quite a lot of confusion in the market about the so-called threat of a surplus of LNG too, going on for some years ahead.

So I think it is very timely that Martin should be addressing some of these issues and provide you with BG's perspective. Now, I know that some of the analysts here have actually been pretty hard at work on this same challenge and actually have already come to conclusions, which are pretty well consistent with our own. But nonetheless I do think it is time for us to clarify a little bit more than we have done so far our views about the medium and long term gas market.

Now the other thing, which is slightly different today, is that this is AshleyAlmanza's last meeting as our CFO. Ashley, as you know, has been CFO now for around about ten years. He's been a great contributor to BG Group over that period and there's no doubt we're going to miss him. And I want to thank you now Ashley for all you've done for the group during the period.

Now one of the things he has done for us is to give us sufficient time to reflect on his plans to work out what we're going to do after his departure. And we've been exceptionally lucky in that sense to have found Fabio Barbosa . Fabio was the CFO of Vale and indeed he's probably known to some of you when he's been over here making presentations on behalf of Vale. And he has one other great quality which is going to be very valuable to us and that is his depth of experience and knowledge of Brazil. And I think everyone here knows that Brazil is such a crucial part of our future that I'm quite sure we're going to get great value from Fabio's insights on Brazil, as well as a CFO.

Well with that I'd like Frank to start the programme going. Thank you.

Chief Executive: Frank Chapman

Slide 3: Introduction

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

Slide 4: Legal notice

I draw your attention to our usual legal notice which I'll leave you to read later.

Slide 5: Agenda

2010 was a pivotal year for BG Group as the largest growth opportunities in our history began to crystallise. Today's presentation will provide an update on the progress we are making with these key projects; as well as expressing our views on the business environment.

Our aim is to provide further insights into the value and future potential of our business. In a moment, Ashley will take you through our 2010 results. Then Martin will talk about our perspectives on global gas markets and brief you on our LNG business. Then I'll update you on the progress in our major growth projects and talk about the long-term outlook.

Slide 6: Key messages 2011

To begin with, here is a summary of the key points from last year's presentation. Now, 12 months on, how have we delivered against this agenda?

We're reaffirming our E&P growth range of 6 to 8 percent out to 2020 – and as I will show, it's now feasible to deliver the mid-point 7 percent from our existing discoveries.

We're reaffirming our goal of 20 million tonnes per annum of LNG supply by 2015 – and we'll show today a supply potential of 30 million tonnes by 2020.

Brazil is larger and of a higher quality than outlined this time last year. It is now BG Group's view that these fields could support net production levels above 550 thousand barrels oil equivalent per day by 2020.

We've sanctioned the Queensland Curtis LNG project, as planned, and construction is underway.

Our US shale gas business, is on course to produce 190 thousand boe per day net by 2015 – almost double the volumes presented this time last year.

We're increasing our LNG profit guidance, to between 1.9 and 2.2 billion dollars per annum to 2012 – profits that we expect to expand further on the back of a 50 percent volume growth by 2015.

And we've again grown our total reserves and resources base, adding another 1.7 billion boe.

So, 2010 has been a year of delivery. This continuing progress with our growth programme, sustained now over many years, flows from the clarity of what we aim to achieve; clarity about our investment proposition and our objectives – and clarity about our strategy.

Slide 7: Investment proposition

It begins with our investment proposition: we are an internationally diversified integrated energy business with a specialism in gas, and our objective is to deliver rates of growth that are a multiple of the industry average.

Slide 8: Strategy

The vehicle for delivering this investment proposition is a clear, effective and resilient global gas strategy, founded on a deep understanding of our target markets and a broad set of customer relationships.

We couple this with the skills to identify, to commercialise and to connect to those markets the long-life, competitively priced resources that are the foundation of sustainable value creation. Importantly, while retaining our distinctive gas focus, we are also able to adapt our approach.

For example – applying our skills and resources to oil opportunities such as Brazil, and seeking to secure a material increase in our exposure to oil prices; actions guided by our drive for shareholder value.

Slide 9: Competitive advantages

The consistent pursuit of this strategy has enabled BG Group to assemble what we believe to be a distinctive combination of competitive advantages.

It begins with a focus on gas markets, which we believe are set to grow strongly. We are a leader in international gas marketing. We have a strong and balanced portfolio of both markets and resources. We have a flexible and highly profitable global LNG business. We are a leader in exploration, with a track record which has sustained growth in our long-life reserves and resources base. Much of this resource resides within a pipeline of economically robust growth projects that are being fast-tracked from discovery to project sanction and first production. And underlying this development tempo is a cost structure which remains top-quartile.

So, nine sources of competitive advantage, behind our track record, and our current plans, and supporting the future opportunities that we will continue to create.

Slide 10: Performance: E&P

We have a production profile, grounded in resources and developments, which we now believe can reach or exceed the upper end of our 6 to 8 percent long-term growth range. This translates into 1.6 million boe per day in 2020. That would represent an average growth rate of 11 percent per annum sustained over a 23-year period from 1997 to 2020.

Slide 11: Performance: LNG

We see a similar pattern in LNG, with supply growth averaging 21 percent per annum over a 12-year period to 2015. And we're now modelling a supply potential of 30 million tonnes.

Slide 12: Performance: TOP

Both of those trajectories have in turn driven operating profit growth, by an average of 29 percent per annum over the last 13 years; momentum that is now on its way to being restored as we recover from the 2008 financial crisis.

We are going to return to all of these themes later. But first, here's Ashley to take us through the 2010 results.

Chief Financial Officer: Ashley Almanza

Slide 13 – 2010 Results

Thank you Frank and good afternoon ladies and gentlemen. If I can just begin by saying as the Chairman has pointed out this is my final presentation and I'd like to take the opportunity to thank my Board colleagues, my colleagues in the company, and all of you here in the room today and listening for the tremendous support that you've shown me over the last nine years. So let's take a look at the results starting with the Group highlights.

Slide 14 – Group highlights

The Group has reported good results with operating profit up by 9% and cash flow from operations up by 10%.

Earnings per share rose by 18% as the operating result was enhanced by lower interest expense and a lower effective tax rate of 38.5%. For 2011, we expect an effective rate of around 39%.

We ended the year with gearing of 20% and the Group remains soundly financed. During 2010 we extended our debt maturity profile considerably and increased our committed facilities.

As you will see from today's presentation the outlook for the Group is positive, with the business well positioned to resume strong growth. That positive outlook is reflected in the Board's decision to increase the full year dividend by 10%.

Those are the highlights, now let's look at the results in a bit more detail, starting with E&P.

Slide 15 – E&P operating profit

Outages on Erskine, Hasdrubal and Panna meant that E&P production increased only slightly this year, by some 800,000 boe. Realised prices however, were up strongly, especially in the second half, and unit opex came in at $7.28 per boe in line with our guidance. The combination of these factors meant that E&P operating profit before exploration expense was up by 9%.

Exploration expense was 18% lower than last year, almost entirely due to lower well write offs. This reflects a very positive drilling campaign in 2010, our major wells in Brazil, Tanzania and China all coming in as successes.

In 2011, we expect exploration spend to be around $1.4 billion, with around half of this being expensed.

E&P total operating profit after exploration expense in 2010 was $3.8 billion dollars, a 17% increase year-on-year.

Staying with E&P let's look at some of the key non-financial metrics, starting with proved reserve replacement rates.

Slide 16 – Proved Reserves Replacement

In 2010 we had a reserves replacement rate of 224% - equivalent to 529 mmboe. This is a net figure, after deducting 62 mmboe for price effects, mainly in relation to Karachaganak.

The effect of acquisitions and disposals was a further net reduction of 12 mmboe.

After adjusting for these effects, the underlying, organic reserve replacement rate was 256% - equivalent to 603 mmboe.

This performance ensured that our competitive position remained very strong indeed.

Slide 17 – Proved Reserves Replacement

This next slide shows our one-year and three-year reserve replacement rates on the left hand side and our competitive position on the right hand side.

Our three year replacement rate is 223%. This includes the net positive contribution from acquisitions and disposals our organic three year rate is 190%.

The chart on the right hand side is prepared using independent data from Evaluate Energy and it confirms once again that BG Group continues to sustain a highly competitive reserve replacement ratio.

Frank will discuss our growing resource position and our projects in more detail and I'm sure it will be clear that the rapid growth in our total resource position together with the number and scale of projects in development, means that the Group is well positioned to deliver strong reserve replacement rates for many years to come.

Now reserve replacement rates are of course reflected in finding and development costs.

Slide 18 – E&P Benchmarking

The left hand side of this chart shows our rolling three year F&D costs.

The industry, as we all know, has experienced rising F&D costs in recent years. However, through cost-effective reserve additions, BG has managed to sustain top quartile performance in seven of the last eight years and we expect that once peer data is available for 2010, our three year average F&D cost of around $16 dollars per boe will once again be in the top quartile of our peer group.

We also believe that BG's strong portfolio of projects already in development will sustain our F&D performance well into the future.

The right hand side of this chart compares our unit opex with that of our competitors.
Here too BG Group has been a top quartile performer for some time now.

For 2011, we estimate opex inflation reflected in our portfolio of between 5 and 10%. I think that will once again position us very strongly.

Now let's look at the LNG segment.

Slide 19 - LNG

During 2010 we saw some demand recovery, especially in Asia, coupled with good weather-related demand.

In these conditions we were able to use our flexible supply chain and market knowledge to divert cargoes to high-value markets. As a result, we posted operating profits of $2.2 billion in our Shipping and Marketing business, which was in line with 2009.

Operating Profit from our liquefaction business was also in line with 2009, coming in at $326 million dollars.

Overall the LNG segment delivered an operating profit of $2.4 billion dollars.

Slide 20 – T&D Operating Profit

In Transmission and Distribution total Operating Profit was similar to 2009 levels at $ 711 million.

Comgas saw a strong recovery in demand with volumes up 16% year on year and underlying profit, excluding the timing effect of gas cost recovery, was up by 19%. Our T&D businesses in India, Gujarat Gas and Mahanagar Gas, continued to grow well and they posted a combined operating profit of $113 million – an increase of 64%.

Slide 21 – Outlook

Moving from historical data to the outlook, starting with the E&P segment.

Slide 22 - E&P Outlook

As you know, we plan to grow our E&P business at a compound average rate of between 6 and 8% out to 2020.

However, if you look at the first five years of our Plan then it becomes clear that this growth is front-end loaded. From 2010 to 2015 the compound average growth rate is 14% per annum.

2011 is a transitional year with growth approaching the bottom end of our long-term range of 6-8%. And then from 2012, growth accelerates above the average rate as new production ramps up in Brazil, Australia and the USA. Frank will describe in more detail, the projects underpinning this growth.

Slide 23 – LNG Outlook

Our next slide summarises the performance and near-term outlook for the LNG segment.

Over the next two years we expect to deliver around 13 million tonnes of LNG per annum. And based on our current view of the market we expect our LNG segment to deliver operating profits of between $1.9 and $2.2 billion dollars for each of 2011 and 2012.

Beyond this time horizon, two very important factors come into play.

Firstly a step change in our LNG volumes; and secondly, we expect the LNG supply-demand balance to tighten during this period. Martin will say more about this in a moment.

Slide 24 – LNG

This chart shows our LNG supply plan out to 2015.

The step change I referred to begins in 2014 as the first train of QCLNG comes into production. By 2015 the second train comes into production and our supply portfolio will then have long-term, low cost supply of around 20 million tonnes per annum. This represents about a 50% increase on today's supply level.

Now, it is also very important to remember that QCLNG volumes have been sold on an oil index. This means that 75% of our LNG sales will be oil related by 2015. For the Group as a whole, around 70% of our sales are expected to be oil or oil indexed by 2015, compared with 50% in 2010. This is an important change taking place.

In summary then the outlook for the LNG business looks very strong indeed – a sustained and material contribution which is expected to rise sharply in 2014 as our new supply comes into production and as market conditions begin to tighten.

Slide 25 – Capital Investment outlook

I'd like to now turn to our capital investment plans. Our capital spend during 2010 was $ 9.2 billion. This included $1.5 billion for US shale acquisitions and our new exploration activity in Tanzania.

Looking ahead, we expect our capital investment to be around $10 billion this year and around $11 billion in 2012. As you would expect, our spend is focussed on our major projects in Brazil, Australia, the US and the UK.

Now, I'd like to take a moment to compare this outlook on capex with the capex guidance we laid out last year.

Slide 26 – Annual capital expenditure

Firstly, we need to rebase our original guidance to 2011 reference conditions and this adds about $500 million, almost entirely due to updating our exchange rates.

Investment in our expanded US shale business adds a further $1.8 billion over the next two years. As you will see from Frank's presentation we expect that our US business will make an increasingly important contribution to E&P production in the years to come.

Slide 27 – Capital structure and dividend

Turning now to the balance sheet and the dividend:

We ended the year in a sound financial position with gearing of 20%.

During 2010, we entered bond markets in the UK, Europe and the US, substantially extending our debt maturity profile. At year end we had gross borrowings of $9.7 billion dollars of which $8.4 billion dollars is long term debt.

To reflect the growing scale of our business, we also increased and extended our credit lines and ended the year with $3.5 billion dollars of undrawn, committed facilities.

Our operating cash flow is healthy and it is growing strongly. We expect that this cash flow, together with our strong balance sheet, will enable us to fund our investment programme and support a growing dividend.

The Board has therefore recommended a 10% increase in the full year dividend. Our dividend policy is unchanged: we aim to grow the dividend in line with long-term earnings growth.

So, let me close by summarising the key points:-

Slide 28 – Summary

The Group delivered a good performance in 2010 with earnings per share up by 18%

The business is now well positioned to sustain strong growth:

Over the next five years we plan to grow E&P production at an average, compound rate of 14% per annum.

Our LNG business is established on a solid foundation: delivering sustained and material profits. And by 2015 we expect our LNG supply portfolio to have grown by around 50% from today's level.

In our T&D business we are seeing good demand recovery and our businesses are ideally positioned to capture the demand potential which is clearly evident in Brazil and India.

All of this adds up to a very positive outlook and that outlook is reflected in the recommended dividend.

Thank you; I'll now hand you over to Martin. Martin.

Executive Director and MD, Americas & Global LNG: Martin Houston

Slide 29: Markets and LNG

Thank you Ashley. Good afternoon ladies and gentlemen.

Slide 30: Global gas major

Frank has set out our strategic framework. So I'm now going to focus on the left-hand side of this slide to set out our perspectives on how markets are likely to evolve.

Natural gas remains the focus of our portfolio, although we also have good exposure to oil – indeed much of our gas-revenue is now oil-indexed. I'll begin by explaining our view of how the next decade will see a dramatic increase in gas demand that is unlikely to be met from the supply sources we see today.

Slide 31: Demand outlook

Here's our outlook on demand across the world's major markets. We expect each of these regional markets to grow through to 2020, with the strongest growth in Asia, led by China. We expect annual growth of 3 percent – and for context, the increase in demand by 2020 is equivalent to more than the entire current North American gas market. It's also worth noting that almost 60 percent of this demand will be outside the OECD.

Slide 32: Drivers of growth

And the market segments driving that demand are also changing in an important way. In the past, most demand growth was driven by power generation, with gas largely substituting for coal in developed economies. In future, we think the strongest demand growth will be driven by oil substitution in emerging economies, mainly in the industrial, commercial and residential sectors. This follows a well-established trend in the markets of Japan, Korea and Taiwan, and would underpin gas as a premium-priced, oil-indexed-fuel over the years ahead.

Slide 33: Oil indexation

We think oil indexation will remain the norm for gas contracts in non-traded markets. Let me explain why. Oil is traded globally against deep and transparent indices. Buyers and sellers have broad confidence that the oil price – over the longer term – fairly reflects macro-economic energy-supply and demand conditions. Over many years, this transparency has given confidence to Asian LNG buyers in particular. Of course, oil indexation not only provides certainty for buyers, it also provides certainty for sellers in an industry where long-term cost trends are linked to the oil price.

Our recent experience in marketing almost 10 million tonnes of LNG confirms that oil indexation is still regarded as the norm for long-term supply contracts. We believe this will remain the case for the foreseeable future. Finally, we estimate 75 percent of the increase in global gas demand will compete with – and therefore be priced against – oil.

Let's turn to the outlook for global supply.

Slide 34: Global supply

Today, this is a little over 3 thousand bcma, around a thousand bcma below demand expected by 2020. However, we think that the supply challenge is much greater than this. Over the decade, many existing conventional and unconventional resources will approach end of life. We believe this amounts to more than a thousand bcma in lost production. So more than 2 thousand bcma of new supply may be required. Now, a variety of new supply sources could fill this gap. There's unconventional gas in the US. New supply is also anticipated from Russia and Central Asia and from the Middle East.

In LNG, a number of new liquefaction facilities may come onstream, potentially delivering around 130 mtpa. Finally, we expect new supply from a variety of other sources across Asia, China and South America. If all of these were delivered on time, they would fill the 2020 supply gap.

But let's be clear – that's a very big "if". The industry would have just nine years to develop this new supply – equivalent to more than three-quarters of current supply levels – to meet expected demand growth. Supply would need to grow at 9 percent a year – a huge endeavour, representing investments of some 2 trillion dollars at average industry F&D costs.

So to put this into context and taking Norway as an example: the industry has less than nine years to develop and bring onstream the equivalent of 20 times the total current gas production of Norway – and this just to meet current 2020 demand projections. So, not only do we see a strong outlook for demand growth, we also see a huge corresponding supply challenge. Any significant supply shortfall would tighten gas-and-LNG prices considerably. In turn, that would benefit companies like BG Group, with material new supply projects already underway and a strong, low-cost reserves and resources position.

So now let's look at the three key regions, beginning with the US.

Slide 35: US market

We expect modest demand growth in the world's largest gas market. The US has abundant shale gas resources that have transformed the domestic supply outlook. So we expect gas prices to remain well below oil parity for some time. This should have positive demand implications, with increased scope for competition with other fuels in power generation, oil-feedstock industries and transport.

Slide 36: Europe

In Europe, we expect gas prices to remain much closer to oil parity than in the US. We expect demand growth will be driven by continued economic expansion, with indigenous supply declining as major existing fields reach end of life. Significant increases in pipe gas and LNG imports will be needed. So we think Europe will remain an attractive high-value market, with gas at the heart of the energy mix. And we think prices will remain strong to stimulate the necessary investment in new pipelines and LNG imports.

Slide 37: Asian market

Turning now to Asia – we expect these gas markets to demonstrate the strongest growth over the next decade. Oil substitution and high economic growth should drive strong demand-growth in the industrial, commercial and residential segments. Although we expect indigenous supply sources to increase, we think that LNG imports will play a key role in the supply mix. We believe that these will rise sharply through the decade, with oil-indexed pricing continuing to incentivise new long-term supply.

Slide 38: Gas penetration

A key market here is China, where gas currently accounts for less than 4 percent of the energy mix – much lower than in comparable economies. An increase of just 1 percent in gas penetration adds around 25 bcma to current Chinese demand. That's equivalent to the total output from four additional trains at QCLNG in Australia. If gas penetration in China were to rise to the level in India – which is still very low by global standards – this alone would result in an increase in Chinese gas demand of around 150 bcma. That's the equivalent of around 100 million tonnes per annum of LNG – in other words, around one and a half times the current total capacity of Qatar.

Slide 39: Chinese LNG

In fact, forecasters generally under-estimate Chinese LNG demand by a significant margin. Three years ago, this was the forecast LNG demand curve out to 2020, a path of steadily rising demand to around 14 mtpa. A year later that curve was revised sharply upwards and then increased further in late 2009 to reach the latest forecast level of 45 mtpa by 2020 – a three-fold increase in just three years.

And to compare this with the contractual reality 2020 volumes committed or under negotiation are approaching levels estimated in 2009. We also believe a further 12 mtpa could come under contract in future, which would then approach the most recent estimates. Finally, the amount of regas capacity already proposed also foreshadows a further demand increase.

Slide 40: LNG supply/demand

Meanwhile, the consensus 2020 forecast for global LNG demand is around 350 mtpa. This is a view of future trade – in other words, the portion of demand likely to be met by new supply. However, it is not an accurate assessment of absolute demand. In fact, we believe it doesn't represent the true supply-demand outlook. And here's why. Current and sanctioned LNG supply is about 280 mtpa which leaves a supply gap of around 70 mtpa. The industry would have to sanction the equivalent of a Gorgon project every year for the next five years to close this gap. That's quite a challenge by historic benchmarks. And on the demand side we believe this will be much higher than 350 mtpa.

We're seeing latent LNG demand in economies such as China and India. There's also a large number of new markets, such as Argentina, Brazil, Kuwait, Cyprus and even Saudi Arabia, now looking to import LNG. So we expect underlying demand well above 350 mtpa. In addition, supply is unlikely to meet forecast levels – let alone meet the true level of demand. In our view, it is supply, not demand, which will continue to constrain the size of the LNG market, leading to an inevitable supply tightness.

I now want to turn to BG Group's distinctive LNG business.

Slide 41: BG Group LNG

This is underpinned by the reality that there is not a single global gas market. Instead, there are many local and regional gas markets, each with different characteristics.

We capture value from both robustly profitable underlying trades and from market imperfections, using an array of assets, skills, our low-cost LNG supply and an extensive network of customers. Traditionally, LNG players built their businesses upon long-term, point-to-point, bilateral arrangements with inflexible take-or-pay contracts. These brought together new customers and new supply sources. Whilst this type of contract does have a place in our growing portfolio, it takes time to achieve the perfect alignment of customers and suppliers. So these arrangements often lead to lengthy development timeframes.

By contrast, we have a flexible portfolio of both equity and third-party LNG supply. This is facilitated by our terminal capacity, by our shipping fleet and by the scale and liquidity of the US market. Taken together, these provide a flexible, risk-mitigation-alternative to long-term, bilateral contracts. In turn, this flexibility has enabled us to establish a diverse set of customer relationships. Our ability to tailor supply to customer needs, free of project-specific constraints and delivery timing, has been key to our marketing success in the Asia-Pacific region over the last two years. We work multiple customer and supply propositions in parallel. It's a virtuous circle of markets then supply – or supply then markets – with optimisation at each step.

Today, our LNG business is sophisticated, fully globalised and highly valuable; and we are relentless in our pursuit of optimisation and value accretion. We've purchased cargoes from 12 out of 18 LNG-supplying countries, and have sold to all but one of the 23 LNG-importing nations. This is a model based on our distinctive sources of competitive advantage. It's an approach which makes the space to satisfy the needs of both sides, and seeks to eliminate risk and project delay, improving the value proposition overall. And it's a strategy which broke the LNG paradigm, which is easier to understand than it is to emulate.

Slide 42: Singapore/QCLNG

Let me give you two specific examples of this strategy in action.

On the market side, we're working with the Energy Market Authority in Singapore to build a downstream customer base which will be supplied from our LNG portfolio through the new Singaporean LNG terminal. In just 10 months, we've built 2.2 mtpa of new LNG demand from around seven customers. Meanwhile, on the supply side, we knew we wanted more oil indexation in our portfolio – so we set about terming-out some of our Atlantic Basin volumes to Asian customers.

Helped by the work in pre-building these markets, we were able to realise a long-term strategic goal; establishing an equity Pacific Basin supply source through our activities in Australia. This allowed us to develop the QCLNG project rapidly and ahead of competitors. Our portfolio approach also allowed us to market freely, unconstrained by concerns about project timing and pricing.

Slide 43: LNG volumes

So, as we look ahead to 2020, we anticipate strong growth in our LNG volumes. We now have around 13 mtpa of LNG supply. We've increased our LNG profit guidance, to between 1.9 and 2.2 billion dollars per annum, out to 2012. By 2015, we expect this volume to increase by around 50 percent to some 20 mtpa, driving a step change in LNG profits. Finally, given the rapid progress at QCLNG, the growth potential within our portfolio and our exploration success, we're now modelling a supply potential of 30 million tonnes per annum by 2020 – a further 50 percent increase.

Slide 44: Key messages

Ladies and gentlemen, we sometimes hear that "the world is awash with gas and LNG, now and into the future". We just do not agree with those views – instead, we expect strong growth in global gas demand through the decade, with supply struggling to keep pace. We expect global LNG to grow sharply, constrained by supply, not demand, and with oil indexation the established norm. And we believe we're well-positioned to take advantage of these opportunities, with a distinctive array of assets, skills and customer relationships and a highly profitable LNG business that today is easier to understand than to replicate.

Ladies and gentlemen, thank you for your attention. Let me now hand you back to Frank.

Chief Executive: Frank Chapman

Slide 45: Portfolio for growth

Slide 46: Global gas major

Thank you Martin for providing some insights into our market-focused approach. I want now to turn to the right-hand side of this picture, beginning with a continuation of the LNG story.

Slide 47: Australia overview

We sanctioned the 8.5 million tonnes per annum QCLNG project on the 31st of October last year. This achievement, only 34 months after entering Australia, represents the realisation of a key long-term strategic objective; to globalise our LNG business through an Asia-Pacific equity LNG position, providing a bridgehead to new oil-indexed regional customers. We are investing around 15 billion dollars in the initial two-train development, with Asia-Pacific customer agreements now almost 10 million tonnes per annum.

Slide 48: 2010 progress

We plan to complete more than 2 thousand wells by 2014, rising to more than 6 thousand wells over the life of the project. Connecting the field to the LNG plant will be a 540 kilometre pipeline network. Construction on Curtis Island is gathering pace. These will be the seventh and eighth LNG trains we've built in 12 years, using the same liquefaction process and the same contractor.

Slide 49: Expansion options

And there is expansion potential beyond the first two trains. In the upstream, we've made good progress expanding and maturing the resources position. Gross reserves and resources have increased from around 5 tcf when we first acquired an interest in QGC to 21 tcf today. So, four times the level at play entry three years ago. At the same time, we've increased 2P reserves six-fold, to 8 tcf.

So, a rapidly evolving and maturing resources picture, which, together with third-party gas opportunities, supports our efforts towards sanction of a third train. In the midstream, our infrastructure is already scaled to support three trains, with only modest additions to facilities. The Curtis Island site is permitted for three trains and has space for up to five – giving a potential of some 20 mtpa. Leveraging existing infrastructure would offer enhanced economics for a third train, with significantly lower incremental unit capex for the plant and midstream. We've already begun to market Train 3 and are confident we can secure further sales.

Slide 50: Australia production

Finally, here's the production outlook for Australia. As a result of all of this progress, we're now well on our way to realising net production of up to 210 thousand boe per day from the first two trains.

I'd like to turn now to another of our major growth projects – our US shale gas business.

Slide 51: US & Canada

The contribution from shale to US and Canadian gas production is expected to more than double, from 20 to 50 billion cubic feet per day, over the years to 2020, at which point it will account for more than half of total production. When considering the opportunities for value creation that flow from this structural change, it's important to remember that methane as the basic commodity is undifferentiated. Cost leadership is therefore the only sustainable competitive strategy.

Slide 52: US cost of supply

Commercial success depends on access to the most prolific resources, combined with competitive cost performance. Over the past 16 months, we have assembled a high-quality, low-cost resource-base totalling 8.5 tcf – around 1.4 billion boe – and offering economic break-even at prices well below current forecasts.

Slide 53: Haynesville

In 2009, we acquired some 3.2 tcf of reserves and resources, at a cost of 40 cents per thousand cubic feet. We have since increased this resource base by more than 60 percent, to 5.3 tcf. We plan to drill around 675 Haynesville wells between 2011 and 2020, with 80 percent of our Haynesville production over the next five years sourced from the highest-quality DeSoto and Shelby core areas.

Slide 54: L48 production

During 2010, the number of rigs operating grew from 14 to 23. We now have more than 125 horizontal wells in operation, many of which have achieved initial flow-rates of more than 20 million cubic feet per day. As a consequence, BG Group ended the year having increased net production by around 300 percent.

Slide 55: Haynesville productivity

We now have around two years' of production experience from 90 wells, giving us an extensive data set. Well performance is consistent with our assumptions, providing confidence in the sustainability and economics of this play.

Slide 56: Haynesville economics

We expect each well in the Haynesville-core, to produce, on average, around 9 bcf, achieving 40 percent of that total within the first two years. We expect to drill around 275 wells in this play within the next five years. Anticipated capex is 9 million dollars per well – that's around 1 dollar per million BTUs, with ongoing opex of around 1 dollar 40. This gives a unit technical cost of around 2 dollars 40 from field to trunkline. Capital efficiency is high, given the very short lead-time from capital expenditure through to first revenues. Consequently, economic break-even can be achieved at gas prices down to 3 dollars 20 per million BTUs, making these projects look very favourable at current forward price assumptions. The Haynesville marked our entry into US shale gas, and we're now applying the experience gained to the as-yet less mature but very extensive Marcellus play.

Slide 57: Marcellus

Here, we acquired 2.9 tcf of resources, at an average cost of 40 cents per thousand cubic feet. With 2 rigs operating, we now have 12 production wells in the area. We expect this to grow to 50 development wells and 10 appraisal wells as we ramp up to 5 rigs during 2011. It is early days in the Marcellus; however, we believe this play has the potential to demonstrate similar core area economics to our Haynesville acreage.

Slide 58: TGGT

Alongside production assets in the Haynesville, we also have a growing midstream joint venture. This provides us with a distinctive advantage over our competitors. We're able to execute our developments without dependence on third-party transmission, enabling us to plan independently and to capture market opportunities. Our midstream JV operates around 1 thousand miles of pipeline. Volumes gathered and treated are expected to increase by more than 30 percent per annum out to 2014, to reach more than 3 bcf per day. These are great assets to own at this formative stage of the industry. They represent material embedded value that will grow rapidly as the network is expanded in the coming years.

Turning now to the production outlook.

Slide 59: US production

We expect to sustain net Haynesville production at around 100 thousand boe per day to 2020. When we add the Marcellus, this brings the net total to 190 thousand boe per day by 2015 – almost double last year's plans. And there is potential to raise this still further, to above 200 thousand boe per day. For context, this would make our US production almost as great as current plans for Australia.

So, we now have a rapidly expanding and capital-efficient shale gas business, with total resources of 8.5 tcf. Moreover, this business leverages our existing US marketing capabilities, and is strongly positioned to benefit from ongoing supply restructuring in the world's largest gas market.

Now, let's turn to Brazil.

Slide 60: Brazil developments

2010 saw very significant progress with our Santos Basin interests:

- we upgraded reserves and resources on Lula, Cernambi and Guará;
- we issued guidance indicating low unit technical costs for the first three FPSOs;
- we commenced production from the first permanent FPSO on Lula;
- and we progressed the contracting of a further 12 FPSOs;

All of this has helped de-risk the development sequence, schedule and project cost, and greatly enhances the visibility of this high-value play – a play where the consortium has signalled its confidence through the commitment of some 13 billion dollars during 2010. This rapid progress is testament to the commitment and expertise of the operator Petrobras, and to the excellent collaborative relationships within our consortium, as we work together to deliver this outstanding growth programme.

Slide 61: First 3 FPSOs

We expect the first three FPSOs on Lula and Guará to recover around 750 million boe per module, more or less double our original estimates. We anticipate capital costs of around 5 dollars per boe and opex of around 9 dollars per boe.

We also expect Brent-parity pricing for this sweet crude, at a transportation cost to world markets of some 4 dollars a barrel.

These parameters underpin attractive economics for these first three units and will be a key building block in estimating the value to be derived from subsequent developments.

Slide 62: Lula & Cernambi

You'll have seen our certified resources upgrade on Lula and Cernambi, details of which are included in your handouts. We estimate gross resources of between 7 and 11 billion boe, with the 9 billion mid-point around 40 percent higher than previous indications. Note that these are BG Group's current estimates. In our view, they do not yet represent the full potential that may be accessed in future through the deployment of enhanced recovery techniques and later phases of infill drilling. Furthermore, continued drilling and testing of delineation wells at field extremities is expected to improve current downside estimates.

Slide 63: Guará

On Guará, our certified gross resources upgrade narrowed the range to between 1.5 and 2 billion boe, and the consortium now plans to deploy two FPSOs on this development. This year, we'll refine our understanding through an Extended Well Test already underway and presently producing around 20 thousand barrels per day, constrained by facilities.

Slide 64: Iara & Carioca

Turning to Iara and Carioca. Last year we spudded the Iara Horst appraisal well, on which we will conduct a DST this year. Future plans include a third appraisal well and an Extended Well Test next year. Last month we reported yet another discovery well, on Carioca North East, which encountered light oil in a 200-metre net reservoir section. A Drill Stem Test will follow shortly. We'll also drill the Carioca Sela appraisal well later this year, and we'll conduct an Extended Well Test.

Slide 65: Santos Basin gas

Associated with these oil discoveries are material gas resources, currently estimated at more than 14 tcf and located within reach of downstream markets served by our Comgás business. During the year, we installed a new pipeline connecting the Lula field to the Mexilhão gas hub, and we're preparing to tie back the first FPSO. This pipeline has capacity for three FPSOs, with further pipelines being planned for 2014. Also in 2010, we completed Front-End Engineering and Design studies for Floating LNG facilities, and expect to conclude our analysis later this year.

Slide 66: FPSO capacity

So, momentum continues to build across the Santos Basin. Let's take a look at plans for FPSO deployment. The first permanent module is already onstream on the Lula field. 2013 sees the second FPSO on Lula and the first on Guará. In 2014, we add a second FPSO on Guará and deploy the first on Cernambi. These are the FPSOs currently being tendered. From 2015 to 2017, we plan to deploy eight more FPSOs. These have been committed to Lula, Cernambi, Iara and Carioca. So, gross production capacity of around 2.3 million boe per day, and all of it expected onstream by 2017.

We're close to the inflection point in our Santos Basin developments, with, on average, more than 300 thousand boe per day of new capacity to be added each year – for the next seven years. Based on the consortium's current agreed 13 FPSO programme, BG Group estimates that this scheduled capacity is already more than sufficient to deliver our net production guidance stated last year. However, there is still much work ahead before the joint-venture finalises field development plans.

Slide 67: Brazil production

In the meantime, it is BG Group's view, consistent with our latest reserves and resources estimates, that we can anticipate further progress. We believe that these fields will, in time, be shown to be of a quality and scale sufficient to support net production above 550 thousand boe per day by 2020.

Let's turn to exploration progress and our resources base.

Slide 68: Exploration record

First, some context on our exploration track record. Since 1997, we've participated in the discovery of 13 giant fields : Aktote, Buzzard, Carioca, Cernambi, Guará, Iara, Kalamkas More, Kashagan, Lula, Margarita, Scarab/Saffron, Simian and Vorwata/Tangguh. At the same time, our total resources base has grown from 3.6 billion to 16.2 billion boe, after some 2.5 billion boe of production.
Underlying these statistics, is 14 billion boe of organic growth – on average, a billion boe of resources added every year for 14 years. I think therefore that it is fair to say that BG Group is one of the global leaders in exploration among our top 30 peers.

Slide 69: A global leader

Here are a few independent statistics supporting that view from Wood MacKenzie which, for example, over the last ten years places BG Group:

- in the top three for achieving high rates of return from exploration;
- shows a sustained 400 percent reserves replacement rate by exploration;
- and an average discovery cost of just 71 cents per boe, making BG Group one of the most efficient explorers in the industry.

When one considers the scale of value created in Brazil, Egypt, Kazakhstan, Trinidad, the UK, and now, most recently, in Australia and the US; it's clear that our exploration activity has added – and continues to add – very-material-value-indeed to the investment proposition.

Slide 70: Prospect inventory

We've grown our inventory by about 12 percent per annum over the last 10 years, to reach today's 3.7 billion boe of net risked resources. Our opportunity set is diverse, spread across more than 200 prospects and leads. There's a good balance between different play types, and around 85 percent of these resources are gas-related. More than 60 percent are in locations where we already have established production, and more than 70 percent are in investment-grade countries.

Importantly, the gross unrisked resources within this inventory amount to around 47 billion boe, 19 billion of which is net to BG Group. Now, when you consider that we operate more than 70 percent of this inventory, it's clear that we're in control of significant resource potential, with scope for material new core ventures in Australia, China, Egypt, Norway, Tanzania and the US.

And in 2011 we'll be drilling-out opportunities in all of these countries.

Slide 71: 2011 E&A

As shown here on this chart. This includes a number of important new play openers. I'd also highlight our focus on appraisal ahead of near-term production, particularly in Brazil. Two areas where we've had recent successes are China and Tanzania.

Slide 72: Tanzania

The Mafia Deep Offshore Basin and the northern portion of the Rovuma Basin are frontier plays where we have an excellent acreage position, amounting to some 28 thousand square kilometres – equivalent to around 140 UK blocks. Our first two wells are significant gas discoveries in high-quality reservoirs. These are encouraging early indications from an area with a wide range of play concepts to be explored.

Tanzania is also another illustration of our market-focused strategy, with the country favourably located to supply growing LNG markets in the eastern hemisphere. The next step will be to test potential prospects in Block 1, with a focus on aggregating sufficient quantities of gas in near-juxtaposed discoveries. We look forward to sharing further progress with you in due course.

Slide 73: China

There are also encouraging early signs from our first drilling offshore China, as the Lingshui well encountered high-quality gas-bearing sands in the deepwater Qiongdongnan Basin. Here, too, we have a good acreage position, with licences on three blocks spanning 15 thousand square kilometres. We are drilling a second exploration well and plan to acquire 15 hundred square kilometres of 3D seismic.

Slide 74: Reserves & resources

As I mentioned in my opening, during 2010 our total reserves and resources increased by some 1.7 billion boe. These now stand at around 16.2 billion boe – up 12 percent year-on-year, and providing 69 years of production at 2010 levels. Our total reserves and resources have grown by more than 8 billion boe over just the last four years – a compound growth of 19 percent per annum. I would also highlight our 2P reserves replacement rate of around 350 percent. This supports our confidence in consistently strong 1P reserves replacement over the years ahead, as we progress our major growth projects.

Slide 75: E&P production

Delivery of that growth begins with the addition of large volumes from Brazil. Then comes the contribution from Australia, here based on our current two-train base case, followed by increasing production from the US. And finally we have production from our other assets. You'll see how these take us to around the mid-point of the long-term 6 to 8 percent growth range – this achievable from the reserves and resources already discovered in our portfolio. Then we have the risked resources from our exploration portfolio, which we believe will allow the top-end of the range to be reached or exceeded.

Slide 76: Key projects

And here's an overview of the key projects that will contribute to that growth profile, details of which are included in your handouts. This includes the major developments we've considered today, together with projects in Bolivia, Kazakhstan, Norway, Trinidad, Thailand and the UK – all of which are included in our current business plans.

Slide 77: Conclusions

So, to conclude, here's a summary of our progress over the past 12 months.

Slide 78: Progress highlights

E&P: growth range of 6 to 8 percent to 2020 reaffirmed, with the 7 percent mid-point achievable from our existing discoveries.

LNG: our goal of 20 mtpa supply by 2015 reaffirmed, with 30 million tonnes supply potential.

And we’ve also increased our LNG profit guidance.

Brazil: we now believe net production could exceed 550 thousand boe per day by 2020.

QCLNG: sanctioned, and progressing towards more than 210 thousand net boe per day.

US shale gas: expected 2015 production almost doubled to 190 thousand net boe per day.

Finally, total reserves and resources: up 1.7 billion boe.

So, I hope we’ve given you today:

- some new insights into the strength and depth of our growth plans;
- the real momentum that is now building;
- and the shareholder value proposition.

But more than this.

Slide 79: Competitive advantages

I hope today has also served as a reminder of the strength we continue to draw from the pursuit of a clear strategy. A strategy that has, over the years, enabled us to assemble an array of competitive advantages, which we can continue to leverage; to win new opportunities; so sustaining our business, and sustaining the creation of long-term value for our shareholders.

Slide 80: BG Group logo

In a moment Ashley, Martin and I will be happy to take your questions, before we do that a few words about Ashley. It has already been mentioned that this is his last strategy presentation and results announcement and he'll be standing down from the Board at the end of March.

I would like to express my gratitude to Ashley for the enormous contribution he has made to BG Group over the years. He has worked with me closely in what I have described as an exceptional partnership. And quite a lot of what you see today in the Group has been the result of some tremendous collaboration. And although Ashley is going to be with us still for a little while, of course I'm sure you'll want to join me in wishing him every success in what he chooses to do hereafter.

His successor Fabio Barbosa, sitting here in the front row - is enormously experienced in all matters Brazilian, but also much more broadly with his financial background and his knowledge of extractive industries. I am really looking forward to working with Fabio as we progress the delivery of what I think is a very exciting programme that we have just laid out .

So thank you very much ladies and gentlemen for your attention. And Ashley, Martin and I will be delighted now to take your questions. Thank you very much.

Q&A Session

Christine Tiscareno,

S&P Equity Research: Could you just give us an update on what is happening in Kazakhstan and what do you think might happen in Egypt. I know operationally you haven't been affected, but could you give us your thoughts as to what would happen with a change in the regime? Thank you.

Frank Chapman: Ashley's going to take Kazakhstan, but let me just take the situation in Egypt, you're quite right in saying that our production operations haven't been particularly affected there. We have had some interference with new development work that we're doing on Phases 7 and 8A and we've had some interference with our drilling activities related to the same projects, because of essentially logistical problems. But those appear now already - to be returning to normal, drilling crews are arriving back and we're starting to get those activities going again.

I don't really want to speculate on what's going to happen in country, that is really a matter for the Egyptian people. What I do know is that we, together with our partners, have spent about $10 billion over the years in developing the gas industry. It's made a huge impact on the local economy, created a lot of value, a lot of jobs. If you look at gas demand and the way it's developed in the residential, commercial, industrial, power generation segments, all of these are up and that is of course a good indication of the contribution.

There is still of course a huge amount to be done in the Nile Delta in terms of development of existing resources and further exploration work. And I feel sure that whatever political persuasion eventually comes into power in Egypt then that government and the people of Egypt will want to see a continuation of the contribution that companies like BG are making to the development of their economy. So troubled times, but, I feel that - given what we're doing in the country we will in time come through this.

Ashley Almanza: Christine, on Karachaganak, we together with our consortium partners are meeting regularly with the government. The dialogue is very constructive, I'm increasingly confident that we will find a mutually satisfactory solution to these discussions. And I think that dialogue is also reflected in the operating environment, which is now very positive, the working relationship on a day-to-day basis between the consortium and the Republic is now on a very good footing. So I think it's right for everybody to work through this patiently and if we do that we're confident that we'll come up with a good plan for the future development of the field.

Jason Gammel, Macquarie: I was hoping that you could comment on the incremental sources of supply that get you to the 30 million tonne per annum LNG case, and I would be particularly interested in comments surrounding Tanzania and floating LNG in Brazil that would potentially play into that?

Frank Chapman: The first thing that comes to mind of course is train 3 at QCLNG and the prospectivity that supports that. If I talk of 21 tcf of total resource base that includes risked exploration (and the risking factors are slightly different in unconventional business) but risked exploration, discovered resources which are under evaluation, discovered resources which are pending development and then probable resource reserves and proved reserves. You've got that whole stack, 21 tcf is the total, that's already enough really more or less for three trains.
But of course we're not committing to train 3 right now because there's a process needing to promote those various resource categories into the proved and probable part of the table; such that you have really confidence about your first two trains before you start promoting train 3.

Ideally we'd like to sanction Train 3 within 18 months of the sanction of the first two trains in order to get construction continuity. So the game is on in terms of conducting exploration and appraisal drilling in order to try to prove up reserves in that sort of timeframe.

Beyond that we have a number of opportunities, you mentioned one of them which is Tanzania, but there are also other things that we're doing. For example the de-bottlenecking processes in Trinidad, we've got the floating LNG thing in Brazil with a lot of gas potential behind that and there are some other things which we're not yet discussing. But, you know, amongst all of this is there a case of 30 million tonnes? Absolutely, you put all this together.

Tanzania, well you know I've mentioned there are encouraging signs. It's always nice to go into a virgin basin, drill two wells and have two very nice discoveries in very productive sandstone reservoirs. This is a good sign and we're on with the programme there. So is that enough of a picture for you?

Jason Kenney, ING: So a couple of questions if I can. Now the global gas market is going to remain tight according to Martin and your LNG volumes are projected to increase and yet you're envisaging a decline in LNG profits over the next two years versus that last two years. Are you just being over conservative on the 1.9 to 2.2, or is this something?

Frank Chapman: Listen, our FD here will tell me it's 1.9 to 2.2 that's our guidance. You know the market will of course be getting a little bit of an idea about how this business has performed, so we thought we would leave you a bit of a puzzle for 2013 and onwards to try and figure out what you think is going to happen with this business. But no I don't think we're being overly conservative, we're giving you what we believe is a realistic outlook. We are of course quite confident, we're not giving you how much is sold, how much is hedged and all of that, we're just giving you some guidance on profitability and we are confident that we will able to deliver within that range. Ashley do you want to add anything to that?

Ashley Almanza: Yes, the only thing I'd say Jason is you will have noted my comment about good weather related demand in 2010. So that was clearly a little bit of a windfall for us, but I'd agree we're not being deliberately conservative. The volume increase that you refer to comes in 2014 and 2015. So I think in broad terms the picture is steady as she goes until 2014 and then we expect it to kick up.

Jason Kenney, ING: Could I ask a follow up question while I've got the microphone? So I can understand the very strong focus on LNG and obviously the optimism from the 30 million tonnes per annum. I'm just wondering how you're going to fund that kind of investment further out and could you envisage a sell down of Brazil in the medium term in order to redirect and rebalance yourself back to your core skill, which is the integrated gas?

Ashley Almanza: I think again you have to look at timing and the third train of QCLNG and beyond that the 30 million tonne case is further out in this decade. So I think that for the meantime - you know there are two things happening here, you've got obviously high levels of investment going into projects over the next few years, but alongside that and simultaneously you've got new projects coming into production, which are going to make an increasingly large contribution to operating cash flow. Once we're through 2013, 2014 I think that the weight of cash flow from those new projects - you have to make your own assumptions about prices and exchange rate, but the rate of the cash flow should be more than adequate.

Frank Chapman: Can I just comment on the business about us getting back to our knitting that you mentioned. I mean let's understand clearly when we drill a well we have an idea about whether it's an oil prone well or a gas prone well. 80% or so of our exploration portfolio is gas prone, but that doesn't mean to say it's all going to be gas, we don't know that until we've drilled these wells.

We of course operating in the deepwater, drilling wells, building platforms, conducing production operations and so on, these skills are common to oil production and gas production. And at the lowest level we take skills and we apply them to opportunities in order to create shareholder value. We are not going to get caught in a strategic cul de sac where we say, unless it's gas we won't do anything with it, you know, if we discover oil we'll sell it to somebody. I think that is a flawed piece of thinking.

We have been very clear about our gas strategy, very strongly growing gas demand, increasing oil indexation in that gas demand, a special set of skills to connect long term, sustainable, economic resources to target markets. All of that has worked enormously well for us and sits behind much of the growth that we've seen. But please don't misunderstand that that means if we discover oil and it's very valuable we'll sell it. We want to create value for our shareholders and we will pursue any route to do that.

I do still think that if you rollout to 2015 to 20 you will still see, as is the case in our plans today more than 50% of the business being gas, okay. So I'm very pleased to say that on value that the market is just beginning to see the visibility of everything we're doing in Brazil. And it's that visibility I think which is starting to - prompt new valuations and new assessments of what we're doing there. And I feel confident that that is going to continue as people gain a better understanding of the real momentum that is growing. I'm sorry I've taken a lot of time. Gas is not a dogma.

Irene Himona, Société Générale: Two questions please, first one for Martin, you make a pretty convincing case about the tightening LNG market to 2020, but obviously near term we have had quite a major dislocation caused by shale gas in the US on the supply side and of course the economic crisis on demand. Can you indicate approximately at what point in time we should expect to see the market begin to tighten, is it the next year or two, it is the middle of the decade?

Martin Houston: Look, I think everybody has got a different number for this one and my number may not be much better than yours. What I would say is that there is a large gap that's opening up and we did have a situation where people expected last year to be awash with LNG, as 40 million tonnes, 22% of new supply came on stream in one year. And actually what happened, if you use the US as a - barometer if you like of surplus LNG in the system , it didn't change.

Actually what happened was a lot of the markets absorbed, much, much more LNG, you know Korea, Japan, China, the UK, Italy,very significant changes in the demand profile. And also of course new markets emerged as well. We're seeing significant demand in South America. I mean cargoes to Brazil, Chile.

Martin Houston: 40 BG cargoes went to South America last year.

Frank Chapman: A new market.

Martin Houston: The Middle East, you know the Middle East is a fast growing market. As I said there's Saudi Arabia potentially as an importer. So, it's not always what it seems. And you know we've already blown through that and it's going to be very interesting to see what happens in 2011.

Irene Himona, Société Générale: Thank you. My second question was if you could just briefly discuss cost inflation pressures in - particularly Australia and Brazil? Thank you.

Ashley Almanza: As I said in my remarks, for the portfolio as a whole we see 5 to 10% cost inflation, certainly in operating costs. That's obviously sensitive to the price environment. We all know that prices and costs go together and if we see sustained oil prices above $100 a barrel then I suspect we'll see, certainly inflation to the upper end of that, possibly a bit more.

In Australia what we've tried to do and Martin can certainly talk as an expert on this since he was closely involved with Kath Tanner down in Australia. But what we've tried to do, Irene is to get in front and to secure our major contracts, main work contracts in the upstream, in the mid stream and also to enter into labour agreements, which we've done now. So nobody can claim to be immune and of course we recognise that particularly in the area of civil works there's going to be more demand for that sort of supply factor in the next 12 months. But I think we've put ourselves in the best possible position in Australia to deal with that risk. It would be a mistake for us to think that the job was finished, we have to continue to manage them closely.Maybe on Brazil, Frank or Martin want to take that.

Frank Chapman: Well I just want to say some more about this issue about skills shortage following the flooding and the disaster down in Queensland. You know - we very much welcome the Federal Government's declaration that they will expedite temporary work permits for skilled labour coming in to help with the recovery. I think that will make a huge difference to the availability of skilled labour, particularly as Ashley mentions in civil engineering, we're talking about road and rail - essentially civil engineering disciplines.

Martin Houston: The only thing I would add on Australia, because I think it's an important point that Frank touched on, which is labour agreements. If we think about labour as being something we often see quoted as being a risk to delivery, and particularly with the recovery work of course that's now got to go on in the civil area within Queensland itself, post flooding. We've got labour agreements that run to the end of 2014, which gives us quite a lot of security in terms of what the picture looks like for us going forward.

Fred Lucas, JP Morgan: A couple of questions, actually three if I'm honest. I take everything you say about the sustainability of oil price indexation, but why are you so confident that governments aren't going to clamp down on the tax leakage that occurs whereby the gas leaves their country at a much higher price, exempt from an upstream tax ring fence. So why won't that oil price indexation get pulled up to the wellhead by governments?

The second question I have is regarding the US and gas shale. There are more and more companies that are firming up capital commitments to US liquefaction, sourced from the US gas shale. I'm just surprised and looking for an explanation as to why that's not a feature of your strategy today.

And a third if I may, given events in Egypt and disruptions to gas supply from Egypt to Israel, ten years ago you discovered around a tcf of gas offshore Gaza, I wonder do you still have title to that and could this situation actually finally unlock that piece of stranded gas?

Ashley Almanza: Taxation again, we would be foolish to be complacent about fiscal creep. But what I would say is that if you think about the production centres that put LNG into our portfolio, in all cases the export agreements around those facilities have been put together at the same time as the upstream. In other words the export has been contemplated at the time that the upstream has been developed. And consequently there are arrangements in place whereby some of the rent in the downstream does net back into the upstream.

So, I think that we would simply point out that what's happening today is not something that was not contemplated at all when these agreements were put in place. And secondly the rent that accrues to the governments in all of these countries is pretty material.

Martin Houston: Fred on exports, I'm not quite sure that a lot of capital commitments have been made as you put it. I think a lot of people have talked about making capital commitments, whether they do is another matter.

First of all there is a lot of unsatisfied LNG demand, if you look at slide 40 and take the arguments that we made. And into that of course exports from the US are not going to make a radical difference. The question you asked was would we - does it feature in our future plans?

Let's just say one or two things about it, massive capital investments are required in this and that capital has got to work long term. It's got to satisfy long term buyer needs and long term seller needs, the latter being more difficult to contemplate from a commercial structure point of view. So if you're talking about the price on the day the seller wants that best price on the day, it may be oil today, but it may be gas in the US who knows, in the future. So the commercial arrangements are not that straightforward.

There are some US policy issues; there are some US sentiment issues that have to be managed as well. All of that said, to answer your question on the nose, have we looked at it? Yes we have looked at it, we've taken a very hard look at it, we have a very good understanding of what the economics look like and we're looking at it to see whether it should feature in the future in our business.

Frank Chapman: You know there may end up being some LNG flowing from shale gas somewhere into the LNG market. But as Martin said the latent demand for LNG is in our view so great it's not really likely to influence materially that picture over the timeframe that we've considered here.

Gaza, yes we still do own the rights to the Gaza gas discovery. You've seen the progress, or ideas flowing from the Blair / Netanyahu conversations. I would say that those are encouraging signs, but they are a long way from providing a comprehensive framework and a comprehensive set of bilateral agreements that would enable a material investment to go ahead. So for the moment we're engaged and we're listening to what's going on. We're not engaged with the Israelis, we are of course as a licence holder engaged with the Palestinian authority, but I think - my feeling is that you shouldn't hold your breath on this one there's some distance to travel. But we still have the rights.

Hootan Yazhari,
B of A, Merrill Lynch: Two quick questions, firstly in Brazil you very kindly in December offered some guidance on the cost structure that we're looking at out there. Obviously the first three FPSOs we're looking at are on the smaller side, you know 120,000 barrels a day roughly on average. The latter FPSOs you're bringing on look to be of 150,000 barrels a day. Can you give us some sort of guidance on the sort of cost savings, economies of scale we could expect there and the sort of recoverability per FPSO we're looking? You're guiding to 750 million for the first three, so I would imagine the next phase is going to be substantially larger than that.

And then the second question, a bit simpler; you've accelerated Brazil, you've accelerated the United States, yet you've kept your production guidance at 6 to 8% alluding to the fact that you could support 7% with your underlying current resources. What would it take for you to move that? And even if you look at slide ten it looks like even the 8% looks very light, or am I missing something here?

Frank Chapman: No, we're not going to change every year our production guidance. This is not really about what we're going to produce in quarter one or quarter two, this is about our long term growth programme and we've given if you like a range of 6 to 8% and we've tried, diligently not to touch that. I mean we haven't adjusted that for the last six years. And it's our intention to stay there.

What of course happens is when you stand 15 years before our projected future, quite a large proportion of what you project is made up of expectations of resources and ventures that will flow from risked exploration activity. And it's a bit like moving resources down into higher levels of confidence. What we're doing as we move forward in time is actually promoting the confidence level that we can get to those growth rates rather than adding more growth rate on top.

If you reset the growth horizon to 2025 then maybe you might do that, you might change these numbers up or down as you start to make allowances for expected exploration performance as you move further forward. But as we move towards 2020 you see that that risked exploration wedge gets smaller and smaller, we took 200,000 barrels a day in 2020 out of the exploration category in one year into firm projects. That's good progress.

So that's what you'll see, you won't see the targets moving so much, but you'll see a confidence level increasing. Amongst all that as well you'll see BG exercising its judgement in whether or not we push as hard on some projects. I won't mention the projects, but you know that we have taken judgements on a number of projects which we've decided to push back in the programme. And those are good, sensible decisions for good commercial and value reasons. So we push them back, some projects fall away, other news ones come in. So you are looking here at a long term growth range that we're aiming to deliver, it's a guide for you. But the composition within that range is going to change and as we move forward to hope to provide a much greater level of confidence.

Of course the numbers that you see in this range have changed, not only as the level that we can achieve from discoveries increased by 200,000 barrels a day. If you look at the profile between now and 2020 it's a lot fuller than it was two or even a year ago, there's a lot more production under that curve than there was, even one or two years ago.

I hope that gets to the heart of your question. I mean if we - as I mentioned in my remarks, if we delivered at the top of that range we would have grown at 11%, E&P production at 11% compound for 24 years. That would be quite an achievement. That's what we're aiming to do.

Hootan Yazhari,
B of A, Merrill Lynch: And Brazil?

Frank Chapman: FPSO size. I think there are two things you need to think about here, firstly the numbers like 100,000 and 150,000 are barrels, so there's quite a bit of gas going through there as well. So when I talk about 2.3 million boe per day you have to make allowances for the gas that's going through as well. So that's sort of grossed up in there.

I will leave you to guess at how to scale the capital efficiency between 120,000 units and 150,000 units. More importantly I think is what we'll be doing to de-bottleneck these units, because you know it isn't a stretch at all of the imagination, in fact it is the norm that facilities can have 10 or even 20% additional capacity through a de-bottlenecking process where you've got really high productive capacity from the wells, which we do have. So that really is probably a bigger factor - to carry around in your mind about how much are they going to get out of these facilities. But I'm sure that there are lots of models that you can draw on to have a crack at the capex profile between a 120 and 150 unit.

Paul Spedding, HSBC: You've painted a picture of Europe that's reasonably - or appears reasonably balanced. We're still getting quite a lot of the purchasers of case within Europe appearing to believe there is a glut and as a result it seems to me that quite a lot of the infrastructure that you will need to deliver that gas, both in terms of LNG receiving terminals and pipelines is - it seems to be sort of held up. I just wonder if you feel there's a probability or chance that Europe could actually turn into a tighter market than even your scenario shows and whether you feel that some of the EU purchasers of gas are taking a bit too much of a risk with our security?

Martin Houston: I think that's an interesting and reasonable observation. What surprised me was the recovery of gas supply from Russia into Europe. The speed with which we went from 2008 down the hill and then straight back up the hill again was remarkable. And, you know, after all the hysteria of the pricing and the volume and what volumes were backed off and Russia and Norway and all the rest of it, I mean it's pretty well come back to 2008 levels. And that - in a set of circumstances where you wouldn't perhaps have expected it. So I whole-heartedly agree, I think it's much likely to be more tight than less tight.

Frank Chapman: And I think I agree as well and that's the reason why we believe that you'll see much closer adherence to oil equivalents in pricing in Europe because you will need that to justify the very large capital flows for investment, absolutely.

Theepan Jothilingam, Morgan Stanley: Three questions actually, firstly just a quick question on your assumptions on the underlying decline rate in what was the old base, or what you now show as other? Secondly I just wanted to get a little bit more colour, if you could flesh out how you think the economics on train 3 in Australia would pan out? And then thirdly I think you've given some very impressive production targets that have been accelerated; I guess one of the questions I get is more on cash flow. And over the last few years we have seen capex, capital investment increase for the group, I was wondering how you saw that going forward and then when exactly you saw an inflection point in terms of free cash flow rather than capex going into the business?

Frank Chapman: Ashley will take the cash flow. Train 3 economics - very little capital investment required in the mid-stream to underpin a third train. So all of the common facilities at Curtis Island, the pipeline infrastructure - these are already being designed for three trains and require very little incremental capex to upgrade them to handle three.

Of course you need the LNG train itself. My guess is that unit development capex for this could be 40% lower than the first two trains. It will be very economic indeed, irrespective of whether one sources that 100% from equity gas or whether there's a mix of some third party gas. I mentioned again in my remarks that we're looking at both things, and either way train 3 looks hugely economic.

Ashley, do you want to take the cash flow question.

Ashley Almanza: Yes. Obviously one of the consequences of being successful in growing your resource base is that you have to grow your investment alongside that, and consequently we have seen investment rising in recent years. When you look at the major areas of investment - Australia, Brazil, the US, to a lesser extent the UK - but the striking thing about those first three is the rate at which production builds up, and you then have to factor in the LNG earnings and cash flow in some of those projects.

So I really go back to the comment I made earlier, which is - you have two things going on at the same time: capital going in, and then a number of major projects coming on stream in quick succession with very steep ramp-up profiles. So we do expect that operating cash flow will grow very strongly. Usual caveat about prices, but nevertheless you can see production ramping up very quickly.

Your question about the peak - obviously we've got now three years of intensive investment, and through that three-year period these projects will come on sequentially. Once you get beyond that, as I said earlier, I think the sheer weight of the cash flow from these projects will give us some questions I think about how to utilise the cash.

Frank Chapman: It's a little bit of a complex equation of course because it's not one field that's declining; it's a mixture of fields which are quite old, mature like Armada, for example, in the North Sea - mixed with other fields where there's ongoing development like, for example, in the West Delta deep fields where we've got ongoing phases. You know, we'll have at least nine or ten phases of development there, and we're at phase 7.

So it's a little bit difficult, but if you just have a look at the chart here, and you take the combination of all of those things together, I mean 2010 those fields produced say, for argument's sake, you can pick it off of here, 600,000, you know, barrels, and that was reduced by less than half over a ten year period. So let's say 50% decline over a ten-year period, that's a compound annual average decline rate of, what, 3 or 4%.

So actually from that perspective it's, as we've always said, quite a low decline rate from the existing assets. It doesn't mean to say you'll get that for free. There's quite a lot of capex that goes into maintaining that plateau. But I'll leave you to pick the numbers off. I'm afraid there's no simple answer to that question, given the combination of many fields rolled into those other assets.

John Rigby, UBS: Two gas questions, and because it's Ashley's last show I felt duty bound to ask a financial one as well. So on the gas ones, firstly on the US, I look on the screen and we're looking at $4.00. You're talking to $3.00 for economic break-even, but you're using a reference price of $7.00. I just wondered how I square that circle, and maybe if you can give some insight into where you think actually prices might go?

The second is - I think Martin will be well aware of this - counting terminals is probably not a great guide for inferring demand. I mean, the US, you'd have gone in at completely wrong direction if you'd done that. So is China looking at terminals the right thing to do? And indeed, could China go the same direction as the US? Have you got any comments on its internal capacity to generate shale gas and tight gas?

And then on the financial one, Ashley - the highlight of my question- you referenced tax rates for this year or 2011. As the mix effects change in the portfolio, how do you see tax rates changing over maybe the next five years, if that's possible? Thanks.

Ashley Almanza: Let me take the tax question first. You know, commonly we don't a, go out more than 12 months on tax rates. There are many moving parts in the tax calculation. I think that, as we go further out, we will see a change in mix - more production out of Australia, more LNG profits and of course more profits out of Brazil.

That will all have an effect, but it just wouldn't be sensible for me to try and predict precisely where tax rates will go beyond 2011. I'm going to save that for Fabio when he takes over [Laughter].

Martin Houston: Okay, I'll take the first two. First of all reference price is $5.50, not $7.00. That's in the appendix on page 81. And actually $5.50 is not that far north of where we could imagine the long-run price of gas to be in the US. 5.00 wouldn't be far wrong. It's going to have excursions north of that, and indeed excursions south. But just for curiosity if nothing else, on the really cold snap last week when it was 12 below F in Texas last week, you know, we were pulling 106 BCF a day in the US.

So, you know, there's a strong latent demand out there, and that demand is constantly being reinforced by state policy as opposed to federal policy, and I think a big drive towards the transportation sector which I believe is going to start working as people look at efficiency as one of the long-term solutions in the United States.

Ashley Almanza: If I could just add - it' very important to distinguish - or draw a distinction - between the reference prices that we use for ease of aggregation in our financial projections and the prices that we use for economic streaming and break-even. So I mean, they're completely different, and the 45.50 is simply for ease of aggregation. If you changed it by 50 cents or a dollar, it wouldn't have a dramatic effect on most of what we've talked about today.

Frank Chapman: Yeah, indeed. I mean, we're talking about economic break-even at $3.20; that's essentially what's driving the core area economics at the moment. I Haynesville how long we believe we can manage to achieve the same in what will become the core areas in the Marcellus.

Martin Houston: Couple more points on the US then. I just said we're at the bottom end, the bottom quartile - the best quartile - of the cost curve. That is not going to supply the entire United States. The cost curve does rise sharply, although there is some flat spot in it. And we've got to remember that decline is quite significant. And as Frank showed on his slide - with the increasing proportion of unconventional within the US gas mix, that number is just going up all the time. So 25, 30%, you know, year on year decline rates is a big pull on new production.

In China, I don't believe they will be stranded terminals because I think - as I tried to say in my remarks - it doesn't take very much change in China to make a very, very big impact. I mean, the 1% case I gave you would only put China at less than 5% gas penetration, which against India is half and against most developed economies is almost nothing.

So I think our assumptions have been quite conservative, and you can really flex that up very quickly. We are seeing very aggressive buying patterns from the Chinese, as I hope those curves showed you - that we've got to almost a 2020 2010 expectation half way before we've got to it. So my sense is that those terminals are being build for a reason and we're going to see them buying LNG on a long-term basis, on an oil index basis.

Lucas Herrmann, Deutsche Bank: Three quick ones. The first really for you, Martin. Elba - you're still taking two million tonnes a year in. To what extent are you able to change configuration around gas? It feels as though you're leaving quite a lot of value on the table, you know, given the opportunity that might exist to sell that gas, that LNG, in other markets.

And then, Frank, I just wondered if you could comment? Any liquids or condensates associated with Tanzania that you'd care to comment on? And finally, just if you could - it was just a question of definition on one of your slides. You talked about 2p or you talked about Brazilian oil pricing off Brent. I got the impression you meant the equivalent to Brent and then a $4 transport charge. Just explanation as to - I think the assumption's an 8% discount or so, but -

Frank Chapman: So it costs you $4.00 to access world prices Brent. That's essentially what we're saying. $4.00. Liquids, condensate too soon to share everything with you on what's happening in Tanzania. What I would say to you is there are a wide variety of concepts that we need to explore there. Okay, so this is just the beginning in a relatively straightforward setting, beginning to do these tests, and having encouraging results. Lot of work to go. So this is not going to be something that we understand the whole story next year. This is going to be some years of work I think.

Martin Houston: Yeah, Elba - I'd make three points, I think. First of all by 2015 Elba will be about 10% on a contracted basis. I mean, that's the fact. The second point is that we do of course at all times try and de-bottleneck the domestic supplies into Georgia and Northern Florida to take out some of that LNG. And quite often we're very successful in doing that.

Then the third point I'd make is - if you'd asked me in November where you could get the highest price for LNG anywhere in the world it would have been in Georgia which was paying $18/m BTU. So it isn't all bad. And those regionally dislocated markets in the United States provide exceptional value at times of big weather excursions. So it's not all as bleak as it looks.

Oswald Clint, Sanford Bernstein: Just a question on the US again, please, in terms of your unconventional assets. A lot of capital going over to the oil shale plays at the moment over there. I assume that's not something you're interested in. And does that mean you really have a materiality level in unconventional assets in the US at this point in time?

Secondly, I'm just curious about the Panama Canal opening up in 2014 to LNG tankers. Is that something you're looking at? Is there any opportunity there to start shifting volumes around?

And then, thirdly, just on the 75% of LNG volumes linked to oil by 2015, can you say if there's a proportion of that linked on to S curve type formulas or have particular caps with the oil price?

Frank Chapman: I'm afraid the last one we won't answer because of commerciality. The first two - oil shale we're not playing in that space at the moment. In respect of materiality we're in a learning process right now. We're very pleased with the progress we've made. You know, 60% uplift in resources since we entered the Haynesville, just starting our appraisal work in Marcellus. I think thekey right now is to understand what we've got, to optimise the portfolio, so you may well see things going out and things coming in.

Because,, the name of the game, as I mentioned in my remarks earlier, is to own the best quality rocks and have the lowest cost structure. Without this you will not have a sustainable strategy. So it's very important that where we have areas that are not the best, that we rotate - and it isn't the case in any area that everything's going to be high quality, so we rotate out of the portfolio some properties, and we rotate into the portfolio better properties.

And then of course there are the opportunities to aggregate, juxtapose properties where there are independent owners of small blocks of acreage that can't develop the infrastructure needed to evacuate that - to export those volumes. And there are opportunities either for doing deals or for acquiring acreage.

So that's really the name of the game; we're not doing oil shale at the moment, we're trying to optimise what we've got. And the materiality - we've got to a level which is sufficient to sustain a material business, and I'm not making any further judgement on that at this stage. We'll see what the quality is of everything we've got and we'll see how it evolves. And we'll do this optimisation of the portfolio; but we're not contemplating any major acquisitions, for example, at present. We don't need to do that; we've got, as you've seen, quite a programme in front of us as it stands. Panama?

Martin Houston: I mean, clearly, exports of LNG from the US - if you're contemplating exporting from the Gulf then the twin track of the Panama Canal by 2014 or 2015 is going to be a significant transportation advantage.

I think what we have yet to understand about that - clearly it's been sized such that it will take certainly, Atlantic Max sized ships, which would put it into the 175 category, maybe larger. I don't know whether it will take a Q-Flex or not. But anyway, what has not been worked out is the pricing formula for the Canal, so that remains to be seen, and clearly that will make a difference one way or another on the export economics. But it clearly does open up different trade patterns, yes.

Rahim Karim, Barclays Capital: Frank, I just want to ask you a question around Brazil. Obviously the projections that you've given around the 550,000 barrels a day of production by 2020 are based on your own assessments. You know, Petrobras hasn't come out and necessarily given out the same levels for the period of time. How do you see your negotiations with your partners going through? What risks do you see? And how do you see that progressing over the next two or three years?

Frank Chapman: We base this on our own assessment of what we believe will be economically rational. You know, once you put in place the large building blocks of infrastructure, then of course it becomes economically rational to do infill drilling, to do de-bottlenecking, to install incremental FPSOs in the flanks of the field, for example, and make use of the existing gas evacuation infrastructure and oil evacuation infrastructure; possible other things like floating LNG infrastructure. These sort of things will become economically rational to do. And it's therefore BG's field development modelling which is based absolutely on the current understanding of the reserves level that we have - the reserves and resources that we have in these fields - which delivers what we believe is an economically rational production profile.

At the moment there's a single phase of development, and that is insufficient to optimise economically the recovery of resources from this field. So do I think it's just going to stop and leave perhaps some of the most valuable barrels in the ground? I don't think so. So this is a little ahead of consortium agreements, but it will be economically rational. I would say that it is very clear that both Petrobras as the operator, and other consortium members in the two consortia - very, very committed to doing what we're doing.

Petrobras is doing a remarkable job. If you think we've come only just a little more than four years from the first discovery well to having, you know, progressing 11 FPSOs and tendering another two - 13 FPSOs with all of this production capacity - in a little more than four years, that is remarkable progress. And it's a testament to their performance and the quality of the relationships in the consortium.

So I feel very confident. People have worried a lot about this. You know - will they go and do Franco first and leave you stranded? Doesn't look like it, actually, you know, given the progress we're making. I think that that's a concern we can set aside.

Ashley Almanza: I mean, the acid test here of course is that the consortium has jointly committed to these FPSOs and the drilling expenditure. That tells you - I think gives you the answer.

Martin Houston: We're on our way, absolutely.

Ashley Almanza: Right, absolutely.

Frank Chapman: Right, well look, let me say thank you very much for the full attendance this afternoon and for a very interesting question and answer session. We look forward to hearing more from you and to speaking with you again with our first quarter results which are on 10 May 2011.