BG Group

2009 Third Quarter Results

28 October 2009

Introduction: Chris Lloyd, Head of Investor Relations

Good afternoon ladies and gentlemen and welcome to BG Group's third quarter results.

During the course of this conference call, Frank Chapman, Chief Executive, will take you through the quarter's key business highlights, and then Ashley Almanza, Chief Financial Officer, will look in more detail at the financial results. After this we will take questions.

During this presentation we'll be focusing on our Business Performance as highlighted in our results statement. We will also be making various forward-looking statements. Factors that could cause our actual results to differ materially from the results we currently expect are identified in detail in the statements issued today.

Thank you, and now over to Frank.

Frank Chapman, Chief Executive

Good afternoon, ladies and gentlemen. I'm sure you'll have read our results statement; so let me begin by spending a few moments taking you through the main points.

BG Group's results this quarter demonstrate again the strength of our integrated gas business. Total operating profit was £856 million, down 38%, against a trading backdrop that has seen oil prices fall by 41% and Henry Hub gas prices fall by 62%, compared to the previous year. Cash generated by operations was £1.2 billion.

In Exploration and Production, total operating profit for the quarter was £435 million, as higher production volumes and the favourable effect of a stronger US Dollar partially offset the sharply lower oil and gas prices.

Production for the quarter was up 5% on the third quarter of 2008 at 56.6 million barrels of oil equivalent. This was around 2 million barrels of oil equivalent below the Group's expectations for the quarter, predominantly due to a delay in the start-up of the Hasdrubal facility in Tunisia. Hasdrubal is expected to commence operations by 30 November. The impact of this delay on planned fourth quarter production is expected to be 1.2 million barrels of oil equivalent.

Currently, production stands at some 700 000 barrels of oil equivalent per day. Production is expected to average 700 000 barrels of oil equivalent per day through the fourth quarter which will be an increase of 12% over the fourth quarter 2008. This is in line with previous guidance for the fourth quarter, but obviously Hasdrubal will have an impact on other short-term production guidance.

The main highlight of the quarter is continuing newsflow from Brazil where we saw further material exploration and appraisal success.

In September, we announced that the BM-S-9 Guará discovery in the Santos Basin is estimated to contain recoverable volumes of between 1.1 and 2 billion barrels of oil equivalent. During the drill stem test, data indicated that a permanent production well would be capable of producing initial rates of up to 50 000 barrels of oil equivalent per day.

To prioritise the development of Guará, the partners have agreed it will receive the second Floating Production, Storage and Offloading system (FPSO), with a capacity of 120 000 barrels of oil per day. First production is targeted for 2012.

We also announced a new discovery known as Abaré West, which proved the presence of an accumulation of oil and natural gas. Abaré West is the fourth consecutive BM-S-9 discovery following Carioca, Guará, and Iguaçu.

We have also completed testing operations on Corcovado 1 in BM-S-52. The well flowed both condensate and gas on drill stem testing. The drilling of both Corcovado 1 and 2 has extended the partners' understanding of the Corcovado structure, one of the major structural highs on the edge of the Santos Basin pre-salt area, where the play is still evolving. The two-well campaign has successfully proved both the presence of moveable hydrocarbons and identified additional prospectivity on the flanks of the high.

In the BM-S-11 concession area, the Iara well drill stem test is ongoing. A total of three tests have so far been completed in different zones and a fourth test is ongoing. The well test confirmed the presence of producible light oil. Further appraisal is planned for 2010 and 2011.

Also in BM-S-11, the first of two drill stem tests has been completed on the Iracema well. Early test data looks very promising, and preparation for testing of a second, separate interval at Iracema is underway.

Additionally, the Tupi North-East well is appraising the reservoir to the north-eastern end of the Tupi high. The well has reached target depth and logging is ongoing.

Meanwhile, the Tupi P1 development well is being drilled as part of the Tupi extended well test project, with the aim of collecting dynamic data to support development planning on the Tupi field. Coring of the reservoir section is ongoing.

The extended well test on Tupi Sul has to date produced in excess of 1 million barrels. Results exceed pre-test expectations, showing excellent reservoir performance with good flow rates and sustained deliverability. These results confirm a very large volume of connected oil with very good lateral reservoir qualities. The well flow rate is currently being constrained at some 20 000 barrels of oil per day.

In terms of forward developments, the FPSO to deliver the first 100 000 barrels of oil per day on Tupi is 48% complete and remains on schedule for first production at end 2010. Tenders for the first of two 120 000 barrels per day FPSOs are currently being evaluated. Following Tupi, the second FPSO will be located on Guará.

The major work programme being undertaken this year has so far delivered outstanding results and confirms the technical and economic robustness of the pre-salt play, and this further underpins the material and growing value of BG Group's extensive position in the Santos Basin. I look forward to providing further updates on Brazil in the coming months as activities progress.

Moving now to the US.

In August, we completed our alliance with EXCO, which brings material, competitively priced new resources and supply to our existing US gas marketing business. The alliance is performing well, and we have seen some industry-leading initial production rates across the Haynesville Shale alongside progressive reductions in drilling days per well. Drilling activities are now being ramped up. The partners currently have seven rigs operating and expect to have 14 rigs by the first quarter 2010. Gas transportation capacity of 200 million cubic feet per day has also been secured, and the partners are actively pursuing additional long-term capacity to support the planned growth in gas production.

Turning now to LNG.

Total operating profit for the quarter was £304 million.

In Australia, the Environmental Impact Statement for the Queensland Curtis LNG project was released for public consultation in August. A decision from the Queensland and Australian Governmental authorities is expected in 2010. Good progress towards sanction is being made, with more than 150 wells drilled this year, tendering underway for the pipeline material and construction contracts, and Front-End Engineering and Design for the upstream facilities and LNG plant progressing to plan.

And now over to Ashley:

Ashley Almanza, Chief Financial Officer

Thank you Frank; and good afternoon ladies and gentlemen.

I'll start as usual with the E&P segment.

As already mentioned, production for the quarter was up 5%, notwithstanding delays to the start up of Hasdrubal.

Trading conditions in the third quarter last year reflected the high point in the commodity price cycle. The oil price in the third quarter this year was down 41% and the Henry Hub price was down 62% compared with the same period last year. Against this backdrop, BG's international gas price realisations were 43% lower in US Dollar terms.

Our UK gas realisations were around 31 pence per therm in Q3. For the forthcoming gas year ending September 2010, we have sold around 60% of our UK gas production under various contracts at an average price of around 40 pence per therm.

Unit operating costs were $6.65 per barrel for the quarter, reflecting the additional spend incurred during the peak maintenance season. Our full year guidance remains around $5.90 per barrel.

Turning now to the LNG segment.

Our shipping and marketing business posted a good result, with operating profit of £284 million – a fall of 19% compared with a 62% fall in Henry Hub prices. This result reflects the benefit of our medium-term LNG sales programme and the positive impact of the stronger US Dollar.

A strong performance at Egyptian LNG more than offset reduced profits at Atlantic LNG where we carried out scheduled maintenance. Overall, we posted a £9 million rise in operating profit from our liquefaction business.

For the LNG segment as a whole, operating profits were £304 million.

The outlook for this year remains in line with our previous guidance, with operating profit for the LNG segment of between £1.4 billion and £1.5 billion for 2009.

For 2010, our guidance remains at £1.2 billion to £1.3 billion or $1.8 billion to $1.95 billion at our reference exchange rate of $1.50 to the pound.

As we reported in February this year, under our medium-term LNG sales programme we have contracted the majority of our LNG volumes out to 2013. This gives us confidence in the outlook and we therefore expect this business to post solid results beyond 2010. I look forward to giving you a further update in February.

Total Operating Profit in Transmission and Distribution increased by 29% to £103 million. At Comgás, volumes were 12% lower than last year reflecting the impact of lower industrial demand and fuel competition. However, we recovered £32 million of prior period gas costs and operating profit rose by £23 million to £92 million for the quarter. For the nine months we have recovered £115 million of past costs and at the end of the third quarter, the balance of past costs still to be recovered stood at £58 million.

In the Power segment, Total Operating Profit of £29 million reflected increased profits at our Italian power business due to the phasing of fuel costs during the year.

For the Group as a whole, Total Operating Profit was £856 million and Earnings per share was 14.1 pence per share.

Net finance costs for the quarter of £20 million include the benefit of foreign exchange gains of £20 million. We expect net finance costs for the full year to be £150 million to £160 million.

The effective tax rate for the nine months to September 2009 was 42%, and this is the expected rate for the full year. The quarter’s results include the benefit of adjusting the rate down to this lower level.

The Group remains strongly financed with gearing of 17% and very good cash conversion. Cash generated by operations was in line with 2008 at £1.2 billion. Capital investment was £1.6 billion in the quarter, including £605 million for the EXCO acquisition. Full year guidance, including acquisitions, remains at £5.4 billion.

In summary then, the Group delivered a resilient financial performance for the quarter against a backdrop of significantly reduced commodity prices.

Finally, you will have seen that from the 1st of January next year we will begin reporting in US Dollars. This will improve comparability across periods and with our peer group. The growth in our dividend will be aligned to progression in US Dollar earnings and we will continue to pay the dividend in Sterling. The Dollar-Sterling rate applicable to the dividend will be fixed at the time of dividend announcements.

Q&As

Iain Reid, Macquarie: Hi, there chaps. Can I ask a few questions? Firstly Ashley, on LNG, you said you'd contracted volumes out to 2013, does that mean you have hedged any of the escalators as you've done for 2009 and 2010?

Ashley Almanza: For 2009 and 2010, we've locked in most of the margin and the guidance is unchanged. Beyond 2010 really what I'm saying is it's important to remember that we have volume certainty if you like. We've termed out the volumes and that puts us I think in a good position to expect solid performance beyond 2010.

In terms of what the margin looks like, we'll give you an update on that in February.

Iain Reid, Macquarie: OK, and can I ask a quick question about BM-S-11 as well? In terms of Iara, the language you've used in the bullet point there seems very different to the language you're using on Iracema. You just say that the well tests have confirmed the presence of producible light oil. It seems rather a gloomy statement for a field that's supposed to hold between three and four billion barrels. Is there something we're supposed to read into that or are you still very positive on Iara as potentially being the next FPSO development after Guará?

Frank Chapman: Well there are two parts to that question, first off I don't think we've changed our view about the volumes in place on Iara. We are in the middle of a programme; we have the most important section still to test. And therefore it's difficult to say too much - beyond that about Iara at the moment.

The reason that I guess we've been more positive with the language on Iracema is that we're already well into the testing programme and from one section, which constitutes about 60% of the total net reservoir, already results confirmed. And of course that provides a basis for perhaps a bit more of a bullish statement. We're not announcing figures at this stage because the operator hasn't finished the work and it's normal to wait until the end.

I would say that the results that we're getting from Iracema look very good indeed and I look forward to telling you more about those when we have finished the work.

Similarly, the results from Tupi North East which we're just logging at the moment. The logging while drilling data coming out looks very good. And that's an important test for the continuity of the reservoir in the North East trend on this very large high. And bearing in mind as well the Iracema is 33 kilometres from the initial discovery well and Tupi North East 11 kilometres from the initial discovery well and what we're seeing there is very encouraging indeed.

In terms of development options in the future, what we're trying to do here of course is to find the best reservoir characteristics in this section and we are seeing variability across different areas. And we'd also like to develop those areas which minimise the pre-investment in the gas gathering infrastructure.

Now with the results that we're getting to date I think that, as I've mentioned to you before, there are other options emerging which may accelerate other developments ahead of Iara because of the reservoir characteristics and the desire to reduce gas gathering infrastructure.

Why start with three separate elements to the gas gathering structure when you can have two basically.

So that's where we are. I think that alongside the words that we've used on Iara and Iracema and Tupi North East I think you should take a great deal of encouragement from the statement that we've made today about the extended well test.

You know we've now produced significant volumes, we had a prognosis for what we would see in terms of well deliverability and sustained pressure. And I can tell you that the performance has been significantly better than the quite high level of optimism that we'd forecast at the beginning, or used to forecast the outcome before we started the test.

So we started off with a positive view, the reality is it's actually much better than that and effectively if you sit at the bottom of the well bore on the Tupi extended well test, Tupi Sul, and look out into the reservoir you can see no boundaries. So it is confirming as we mentioned a long time ago in one of our previous press releases that you are confirming that there is a very large quantity of oil connected to this well bore. In fact, effectively you're looking out into infinity.

So it's very, very positive news in my view following on the heels of the Guará announcement this is good news.

Iain Reid, Macquarie: OK Frank, is it possible to say on the EWT what the potential development flow rate could be if you're constrained at 20 000 per day?

Frank Chapman: Petrobras and BG are still working on how far we take this well in terms of limitations we have. I guess the view is that this well could probably do 25 to 30 000 barrels a day.

What ultimately a production well could do with larger tubing and so on, I wouldn't give you a number today. But we're already at a level where you say this is actually a really excellent outcome.

Iain Reid, Macquarie: OK, thanks very much indeed.

Theepan Jothilingam, Morgan Stanley: Good afternoon gents, a couple of questions just to follow up on Brazil and then over to Karachaganak actually. Just on Tupi North East, I just want to understand would that change your view on the upper boundary on the five to eight billion that the partners have announced in terms of a reserve estimate?

And then secondly on Brazil, you've had incredible success, just from a portfolio perspective do you think that your exposure to Brazil development gets too high, or put it in a different way, would you actually start to consider a sell down on part of the position in Brazil?

And secondly on Karachaganak, just simply where we are in terms of production, particularly the demand for the gas off take and then perhaps a little bit of colour on what progress you've made on Phase III?

Frank Chapman: OK, where to start? Tupi North East five to eight billion barrels, I think the significance of the positive reservoir indication is greater for the number of wells and the amount of gross production that we'll achieve per well than it is for the reserves. We're not seeing any surprises at all on reserves and I think it will be quite a way down the road and quite a few wells will need still to be drilled before we start getting a better fix on this five to eight billion.

I mean clearly with some of these reservoirs we're seeing better porosities. But you know it's early days really, we're still talking about half a dozen wells and over an 1 800 square kilometre areas it is quite few data points.

So I think that the most significant point is that with about 55% of the estimated capex going into drilling if you only need half the number of wells for example - I mean I'm just chucking that out figuratively speaking - then clearly that would have a significant implication for the breakeven oil price that this thing would work at and the economics at any reasonable oil price.

So that's really I guess the message that we're trying to convey. And we're also trying to convey that we can group these developments we're going to save on infrastructure costs. So you can imagine that the field development planning people are in overdrive at the moment as they are assimilating all this new information and working up the various permutations for development.

So if we come out at some point in the future with a revised sequence of installing FPSOs I don't think you should be surprised about that. This is I think a logical optimisation process that needs to go on and will probably continue for quite some time.

Now Brazil, do we think exposure is too high? Not at the moment. I mean you have to take these things as a whole, people often refer back to Kashagan, but I do like to emphasise to people that we're in quite a different position here.

We're actually managing to have really a significant influence on how we're performing the work, how we're developing field development plans, you know really a close partnership, where essentially BG and Petrobras are working together. Petrobras obviously the operator, supported by BG. And that is a very different situation where we had a lot of very large and powerful operators trying to have an influence on Kashagan and we just weren't comfortable in that environment and decided we wanted to exit. And we were comfortable with that decision.

So I think that we will follow Brazil and certainly at this stage there are no plans to divest. This is going to be a great value driver for the company out into the future. It is going to drive production right the way through the next decade, possibly 4 to 500 000 barrels a day BG net. So we'll be following this, we have more than sufficient financial capacity to follow this play. And the more you get to know about it the lower risks get and I guess we'll want to follow this as far as we can.

Production in Kazakhstan - we have seen and continue to see significant gas side weakness. And that has been the whole of this year we've repeated in three quarters that there has been demand side weakness. We've been utilising everything at our disposal to try and offset those issues. And we've had some success with ‘produce the limit’ initiatives which I mentioned in 2Q, areas where we had succeeded there. But we are still seeing, for example much later than we'd normally anticipate quite low summer demand levels, not withstanding the fact that we are now entering what we call the winter demand period, in Kazakhstan we're still seeing some weak demand there.

Phase III was your last area, we currently are close to consolidating the joint operators' views on how to breakdown Phase III, we now see four stages for Phase III. I won't be specific because we still want to put these in front of the government. We think still that this is going to be, as I've mentioned before, economically far more beneficial to both investors and the government. And I envisage that we will be placing these development plans in front of government and key stakeholders before the end of the year.

Theepan Jothilingam, Morgan Stanley: Thanks very much.

Hootan Yazhari Bank of America Merrill Lynch: Hi there gentlemen, just a couple of questions one on LNG and one on Brazil. You've painted a pretty bullish picture on Brazil, mainly on the back of some strong flow rates that you've seen in BM-S-9 and BM-S-11. I just wanted to see if this is likely to have any impact on recovery factors and whether we will see any sort of change to guidance on the recoverable reserves figure? That's the first question.

And the second question relates to LNG. We've obviously started to see some diverging pricing trends in the Atlantic Basin and in Asia. Has demand in Asia starting picking up such that you can - exploit arbitrage opportunities or diversion opportunities in the fourth quarter? Thank you.

Frank Chapman: Let me just answer on Brazil, clearly if you're getting very good permeability and your analysis suggests that you're collecting very large volumes then there is potential to improve recovery factors. And the old adage that large fields tend to get larger is generally not because the gross rock volume changes, but generally we tend to get better recovery factors as we learn about the behaviour of the reservoirs and the fluids.

But I wouldn't change our guidance at the moment, as I mentioned to Theepan a moment ago we'd like some more calibration points. But you know it's very good news to go and drill successive wells and find out that actually the discovery well you drilled wasn't the best reservoir and that you've found a succession of areas which look significantly better.

Ashley Almanza: On LNG I won't comment on the fourth quarter demand pattern that we're anticipating. We'll be happy to report on that after the quarter. But I think the key thing Hootan here to keep in mind is that we have locked in our Asian, European and North American demand largely for this year and next year. And indeed the majority of our volume, the demand is locked in out to 2013.

Around that we still find opportunities to supply marginal buyers at attractive prices and the number of buyers of course is growing because the number of import facilities around the world is growing. So on balance, we continue to expect to see from time to time good opportunities to continue to divert supply.

Hootan Yazhari Bank of America Merrill Lynch: Thank you.

Michael Alsford Nomura: Good afternoon, I've got just two questions around the EXCO position. Firstly can you maybe give us a bit more colour as to your plans to go forward with those assets in terms of the ramp up of production we could expect, given some of your positive comments around the flow rates and the fact that you're looking to take and work with more rigs in the next couple of months?

And then also just around the position you have there, could we expect you to be increasing that acreage position over the coming 12 months or so, or would you say you're happy with the position you've already got? Thanks.

Frank Chapman: On EXCO, the figures that we've given previously which we haven't updated are that we're looking to expand production from something more than 70 million to 250 million standard cubic feet a day, BG net, by 2012.

We are seeing some good flow rates in the Haynesville, the last well we tested came in at above 30 million standard cubic feet a day well initials. So we are seeing a confirmation of the low cost structure that will result from these very high well initials.

In terms of this play in general, we're clearly not going to do anything in the portfolio which is not going to be material in terms of our overall resources base. It's not worth pursuing a completely new play in a completely new area unless you believe you can make it material and significant, relative to the rest of the resources base. And I think that we haven't sort of given indications before that we are going to work hard at aggregating more in terms of reserves and resources, both through organic means and through add on incremental developments and indeed through further exploration of other horizons within the existing licences.

So we have today I think informed you that we have around 2.6 trillion cubic feet net BG, which is about 400 million barrels of oil equivalent or thereabouts and we are aiming to work that number up to a significantly higher number.

Michael Alsford Nomura: Great, thanks very much.

Oswald Clint,

Sanford Bernstein: Hi good afternoon. The first question really back on Brazil please and BM-S-52 and BM-S-50, initially I think it was talked about as a multi- billion barrel potential. I wonder if you could say what that wording or that terminology has changed to now after the testing and the greater geological understanding that you have for Corcovado 1 and Corcovado 2? Does that move to a billion or to a multi-million type range?

And then following that just on Sagittario is that still a well that we should be expecting in the near term?

And my second question is just on - I noticed Origin out this morning talking about some higher than expected flow rates on some of their Australian coal seam gas wells. I wonder if you could say anything on your 150 wells you've drilled this year at the QGC assets? Thank you.

Frank Chapman: Yes, on BSM-52 we're not changing anything we've said on that at the moment. This play is very different actually to the other discoveries that we made. It sits on a structural high, the top of that high is missing; therefore you're penetrating although in shallower water and structurally not as deep you're actually penetrating much older rocks. And the results we've got from this are complex, relative to the sort of pattern that's emerging in the other quite different pre salt plays.

So I don't want to say any more on this. Results analysis is ongoing, we see further prospectivity on the flanks of the structure and we really need to decide, we'll work through the analysis and decide how we're going to take this forward.

I think the most important thing for us to recognise at the moment is that we are changing priorities all of the time in Brazil as we see the opportunities to advance production in some of these other areas and we will be adjusting our programme and adjusting our priorities accordingly.

I am pleased to confirm to you though that this is a discovery, Corcovado 1 and it has flowed oil and gas and we're in the process of analysing that.

With respect to Sagittario, we have got a licence extension on Sagittario and as a consequence of that, again similarly we're pushing this out because we want to use capacity elsewhere to advance production. And this is entirely in line with what I've been trying to communicate to suggest those that are following BG should look towards the pace at which we are developing and converting these discoveries into revenue streams as the next big source of value rather than the next exploration well.

Not that I am at all bashful about the potential that still exists in exploration, the emphasis in BG is moving, has moved towards appraisal and getting into production as much as we can at the earliest stage.

With regards to Origin they are a long way behind where we are and they are probably seeing what we have already seen a couple of years ago and we're very happy with the 150 wells that we drilled.

Oswald Clint, Sanford Bernstein: OK, great thank you.

Frank Chapman: I think we've given figures of 13 trillion cubic feet or thereabouts we expect to develop. This is enough for what we're doing there and we're getting on. 150 wells is no mean feat in a year and we're carrying on. We reckon we'll have five tcf of 2P reserves by the time we get to sanction next year. So you know we're very happy with the progress we're making down in Queensland.

Oswald Clint, Sanford Bernstein: That's great, thank you.

Jon Rigby, UBS: Hi good afternoon, can I just have a couple of questions? One is just to go back on the terming out of some of the LNG supply out to 2013.

Can I interpret this as you removing the sort of commercial risk of being able to place cargoes as a first instance, but you've left the price risk, or you may have left the price risk, or you're not confirming that you've dealt with the price risk as that?

And as sort of a subsidiary to that, I'm not expecting you to answer this but I'm going to ask it anyway, whether the terms that - what would traditionally be oil price related markets, what spot buyers are willing to pay has that changed in the last couple of years, I guess recognising the fact that there's more LNG cargoes around?

The second question, I think there was a story in the press about two or three weeks ago that you'd received an approach about your power assets and I just wanted to sort of circle back on that and ask you, whether you could confirm or discuss that? And also, I guess broadly, more broadly with all the work that's going on in Brazil and Australia, etc, are you looking at the structure of your entire portfolio and maybe looking at sort of narrowing down some of the activities that you currently have? Thanks.

Ashley Almanza: Jon let me take those in order of ease. On power as usual we won't comment on press speculation. On your question about portfolio - I think we've always said that all assets had to earn their keep in the portfolio and we like to take a fairly unsentimental view. And I hope that that's been shown, certainly there has been no change in our philosophy there.

Underlying your question may have been a reference to funding future developments. Again, I think that given the strength of the balance sheet and the strength of cash conversion we're in a reasonably good position. So anything that we think about in our portfolio is simply driven by a philosophy that assets must earn their keep in the portfolio.

On LNG you're right and I should say this is - I'm not hopefully breaking any new information - there's a chart on our website in the February presentation that shows the disposition of the LNG portfolio out to 2013. And you're right, what we've done is effectively reduced, eliminated the volume risk. Clearly in 2009 and 2010 we've also locked in the margin. And what I'm saying is having eliminated volume risk it puts you in quite a good position to I think feel confident about the outlook for the business.

We've said for 2010, effectively in 2010 we've put a floor on our results of £1.2 billion, we've given a range and the floor is 1.2. And I'm saying, with that as a reference point, I expect a reasonably solid performance beyond that and we'll give you a full update in February.

Jon Rigby, UBS: OK thanks,

Colin Smith, Icap: Afternoon gentlemen, a question on Brazil and another question on power. Just on Brazil timing and scale, I think Brazil's EVP for pre-salt has been quoted as saying that the vessels are going to be 150 000 barrels a day rather than 120. And on Petrobras' most recent presentation the start up for the new vessels which I take to be the first of the two new vessels that you have in for 2012 they seem to have for 2013 and 2014 unless I've misunderstood that. And I wondered if you could comment on that? That's the first question.

The second thing, just coming back on power, you obviously put quite a bit of investment in US power pre 2007 and earnings have not been notably better in 2008 or 2009, if anything a little weaker. And I wondered if that was down to the non-US business or the US business? And if it's the US business, can you just say what's actually going on there against your former expectations? Thank you.

Frank Chapman: On this size of vessels, we started off with 100 000, we're now looking at 120 000 and the 120 000 units we're also designing to deal with a variety of reservoir fluids so that we'll have the possibility to move these vessels as we get more data and we have more flexibility in where we deploy these vessels. And this is pretty much in line with what I told the market in February.

We're also looking at a range of much larger vessels as well. So there will be areas where we choose to use much larger FPSOs, but again I don't want to make any formal forecasts of where that work is going because the work isn't finished. But you shouldn't work on the assumption that all of the FPSOs from now on are going to be 120 000. We're looking at a variety of solutions which will be tailored to some of them, tailored to the specifics of reservoirs, these earlier ones while we're still gaining knowledge will have a degree of more flexibility.

New vessels, this 2013/14 thing is a remnant I believe of a discussion that we had earlier on in the year where there were some conflicts between a strategy statement that was made - we dealt with this in the February presentation, a strategy statement that was made by Petrobras and the content of two sets of view graphs that they used.

The position that is in their earlier this year strategy statement and is consistent with what we have said, is that the next unit which is now confirmed to be going on Guará is targeted for 2012. The unit for Iara which may shift, you can take that from my comments that I made earlier, but that number three unit if you like was targeted for 2013 but the teams are identifying that they wanted to work hard to bring that forward to 2012, but we had said 2013.

So that's where we are, I think that's where you will see Petrobras is if you go back and look at their strategy release and that's what we're working to. I think the only difference is around the sequence and the number of vessels and ultimately their size and how we deploy them, which I think is likely to change and continue to be refined as we gather more data.

Ashley Almanza: Colin, on power it's a combination of factors - actually the results in Italy year on year for the full nine months is down. We enjoyed some one off receipts last year in Italy. The US continues to make progress; the business is growing in profitability. However, it is fair to say that the outturn over the last two years has been disappointing. And that is reflected particularly this year in weaker demand across a broad front of users in the US.

I think we would say that if you look at the disposition of gas fired power generation in the northeast of the United States that it remains our conviction that that will turn and that the value of these assets will be reflected ultimately in their financial performance. But it will take a bit longer than we had hoped.

Colin Smith, Icap: I mean just given where gas prices are, obviously I guess my assumption would have been that they would have been running flat out and taking cheap gas in, is that not happening or is that happening and it's still not generating as much as you might like?

Ashley Almanza: No I think that for the period that Henry Hub dipped down very sharply we did see switch and we enjoyed some of that benefit. But that is a small period. I think your question was - I took your question to mean, what's the trend since acquisition? So I think the dip in the Henry Hub price undoubtedly helped gas fired power generation to the extent that there's dual fuel generation people switched to gas there's no doubt and we saw a little bit of that. But as you've seen Henry Hub has bounced back up.

Colin Smith, Icap: OK, thank you.

Lucy Haskins, Barclays Capital: Hi, good afternoon Frank and Ashley. I just wanted to ask about - clearly there is a current disconnect between your reference assumption for this year of $55 oil and $7.25 Henry Hub. I mean do you think this is just a temporary feature or do you think we are looking at more of a structural shift in terms of the sort of oil and gas price connection or disconnect that seems to have opened up recently?

Ashley Almanza: I think you have to look at that by market. And in the case of the United States clearly the rapid development of unconventionals has had an effect. We have though seen the rig count in the United States fall dramatically, more than 60% down in the second and third quarter and we're seeing the price come back.

In other markets Lucy of course gas prices remain more closely linked to oil prices. In Asia and in Europe this is the case.

I think for us we would reiterate what we've always said, which is we're no good at predicting where prices are going to go. We prefer to focus our efforts on understanding supply cost curves in the markets which we choose to supply and endeavour to position ourselves at the left hand end of that supply cost curve knowing that in that situation we'll make good returns come what may.

So on the face of it we wouldn't call it either way, but there's no reason to assume that gas should trade at a discount to oil, because after all it has significant benefits in terms of efficiency and carbon load. But you have to look at it market by market, quite a complex subject but that's the short answer.

Frank Chapman: I think as well it's worth refreshing - just re-emphasising once again that in February we said that we expected our results to be - the forecast that we'd given for LNG earnings to be pretty neutral to any change in Henry Hub gas price in the range of $4 to $7.50. And we have to remember that in some cases we're buying Henry Hub and selling Brent and you know weaker Henry Hub prices don't necessarily mean that our earnings are lower, in fact our earnings from the LNG sections as we've seen are on target. And they exhibit a much more robust set of characteristics then perhaps an oilier competitor would be seeing today with oil prices where they are.

Lucy Haskins, Barclays Capital: Yes, I just wondered whether you did feel over time there was going to be any pressure on Asian and European prices, to be a bit more linked to an understandably smaller sort of stock market than we have in the US? There has been some suggestion by some commentators that you there may be some de-linkage over time, not just in the US?

Frank Chapman: Well you've seen BG in the past acting to preserve margins, we of course will continue with that practice. Taking a macro view we maintain the view that we expressed in February this year that over the long term you're going to see quite a significant amount of growth in the LNG market beyond that suite of new projects that are currently coming on stream.

We maintain our view that there will be another 150 million tonnes of new LNG supply required by the end of the next decade, 2020. That is another ten Gorgons if you like – a Gorgon a year to be sanctioned, that's quite a tall order in our view. Some of these projects have taken 30 years to come to sanction and if you look what's happened over the last five years you won't see many projects being sanctioned each year.

So we maintain that long term view. There are at least some other customers and players that share that view, because we have in the last 18 months sold 8.3 million tonnes per annum of LNG. Ostensibly from our Australian venture under long term contracts and give you an insight perhaps into what some of the customers see on the picture changing and the supply picture changing as you go out beyond the near to medium term 2012/13, that sort of period as you go out beyond that time.

Lucy Haskins, Barclays Capital: Thank you for the update.

Dave Thomas Citigroup: A couple of questions on Australia and then one on Brazil. Firstly, on costs in Australia on QGC, can you say something on the trends you're seeing in drilling costs for these wells to date? And then looking further out, how do you intend to mitigate against an over heated construction market that might appear around Curtis Island LNG projects with consequent upward pressure on development costs there?

Secondly on QGC, before LNG export starts what will be the maximum production from QGC into the domestic market? And then moving to Brazil, perhaps you can provide some comment on what the plans are for dealing with the gas, there are obviously oil and gas reservoirs here, in terms of re-injection, export pipelines or indeed floating LNG?

Frank Chapman: Yeah, OK - I mean drilling costs you know it's amazing how quickly an organisation can adapt to doing something entirely new. When we started this process of Australia we wondered how much of our drilling capability would bear on the existing practices of QGC. And we've got now a suite of changes that we're making which we believe will significantly reduce the drilling costs. And this is not just performance related; this is fundamental well engineering processes.

We're also looking at opportunities which are not obvious actually, but to drill multiple wells from a single pad using inclined drilling for example, as a means of reducing the cost of preparing multiple drilling pads. There is a whole bunch of simplification, down hole simplifications that we're looking at. Reducing the number of pieces that are used, getting rid of the blow preventers for example, these wells kill themselves when they flow. Putting all the rigs now on the floor instead of sitting on top of a substructure. There's a whole bunch of simplifications that we're looking at bearing in mind that these wells, when we drill a good well, they TD inside of 24 hours. So this is a real production line type of exercise and we're making really good progress with deploying our traditional, sort of conventional drilling skills to a new sort of problem.

Mitigating against an overheated local market, the two mitigants that we are deploying is, one to be first and secondly to secure overseas capacity, yard capacity where we will implement a relatively high degree of modularisation. So these are the two principal mitigants.

The maximum production rate into the local market I'm not going to comment on because there are commercial dimensions to that, so I'm not going to mention that at this point.

And the last question you had was Brazil; in terms of the gas evacuation we're looking at various issues at the moment. The first production modules will produce gas through a sub sea pipeline tied back to Mexilhão and from Mexilhão to the beach where we will sell gas into the Brazil system. And clearly our intent there is to take some of that gas to drive Comgás growth.

And we are looking at other means, both tying back to the beach for onshore LNG manufacturing and also a project that we have with Petrobras to work up concepts for the deployment of floating LNG in the field.

So all of these things are being evaluated at present. I would emphasise, it's a very important question you raise because whereas everyone sees the value in Tupi as being oil, we tend to forget how much gas is there as well. And if I just take our P10 case for Iara, Guará and Tupi, our P10 volumes in place amount to something of the order of 60 billion barrels of liquids.

Now these are very large numbers and for every billion barrels of liquids there is a trillion cubic feet of gas. So there are 60 trillion cubic feet of gas in these three discoveries alone. And if you just estimate somewhat conservatively at this stage that you could recover two thirds of that that would be 40 trillion cubic feet of gas. That is a potential equivalent to the mighty Troll. And we know Troll is supplying 10% of Europe's gas. And that is what we're dealing with.

So the gas side of this equation is going to be a very major source of value. And the way we set about the development planning for that will require a great deal of further work but it is clearly for us very much in focus.

Dave Thomas, Citigroup: OK Frank, thanks very much.

David Cline, RBS: Good afternoon, just a question on the UK contract portfolio. You mentioned a year ago that the legacy side of the portfolio had declined in importance to about 30% of the total. And I think you said in the following 18 to 24 months you expected the majority of that to expire. Can you tell us where we are at this point in time in terms of that data point?

Frank Chapman: Yeah, I'll get Ashley to answer that, but what we also said was that although it had declined in terms of its percentage contribution - actually in absolute terms we had managed to rollout the production profile of 50 million barrels oil equivalent level, another six years - compared with what we had presented in our 2006 plan. So it is a smaller percentage of the whole but we've added a huge amount of value actually in the UK over the recent - the last three years.

Ashley Almanza: The situation is that in the course of the year actually some of those have rolled over into contracts, so the contracts have been extended if you like from across all of our gas producing fields in the North Sea. And so they continue to make up a substantial proportion, more than 20% of the total sales.

David Cline, RBS: Thank you.

Irene Himona, Exane BNP Paribas: Good afternoon, I had two questions please, first on capital expenditure; you've confirmed your 2009 spend. Could you just remind us of guidance for 2010 capex? And secondly, a question on the balance sheet, in the past year or so we moved from net cash to 17% gearing, given the substantial size of the undeveloped portfolio, how high would you allow that gearing to go in your reference price scenario? Thank you.

Ashley Almanza: Irene, the guidance is unchanged at £5.4 billion for this year, including acquisitions. We've added obviously some capital expenditure for the out years and with the acquisition of EXCO. We had previously said £4 billion per annum out to 2012 and you need to add EXCO onto that, including the acquisition cost, about $3 billion over the same period.

In terms of gearing I think an appropriate gearing level for our company is around 25% debt - debt plus equity. That's not intended to be a target or a precise analysis, but in that postal code feels like an appropriate capital structure for our company. And if you look at the strength of cash conversion. I think we feel that we're in a reasonably strong position.

Irene Himona,
Exane BNP Paribas: Thank you very much.

Frank Chapman, Chief Executive

Thank you very much for your questions. If I may I'd just like to summarise the main points one more time.

- Production volumes were up 5% on the same quarter last year, with Hasdrubal now expected onstream by 30 November;
- We expect production to average 700 000 barrels of oil equivalent per day in the fourth quarter – approximately 12% higher than the fourth quarter 2008, in line with guidance;
- We've seen further material exploration and appraisal success in Brazil, and the Tupi development is progressing well;
- In Australia, we've made good progress with QCLNG upstream, trunkline and plant, moving towards sanction in 2010;
- And finally, our alliance with EXCO in the US is ramping up, with seven rigs now operating and 14 planned by the first quarter of next year.

Thank you for taking part in the conference call today and I'd like to remind you that we'll be announcing our full year results alongside our strategy presentation on 4th February next year. Goodbye.