

BG GROUP



BG Group

2009 Second Quarter Results

29 July 2009

Introduction: Chris Lloyd, Head of Investor Relations

Good afternoon ladies and gentlemen and welcome to BG Group's second 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 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 statement issued today.

Thank you, and now over to Frank.

Frank Chapman, Chief Executive

Good afternoon, Ladies and Gentlemen.

You'll have now seen the results statement; so let me begin by spending a few moments taking you through the main points.

BG Group's performance continued to show resilience in the second quarter. Total operating profit was £972 million, down 32%, against a trading backdrop that has seen oil prices fall by 52% and Henry Hub gas prices fall by 66%.

Of course, these falling prices reflect the global economic downturn, which has once again this quarter, been evident in weaker gas demand in a number of BG Group's markets. However, in the second quarter BG Group's new production combined with actions to mitigate demand weakness contributed to production rising by 7% year-on-year.

Furthermore, as we progress through the year we expect output to continue to rise, and anticipate a fourth quarter average production rate in excess of 700 000 barrels oil equivalent per day, up 12% on 2008's fourth quarter. Attainment of BG Group's 2009 production target of 680 000 barrels oil equivalent per day, is therefore expected to be

achieved over the 12 month period to 31 March 2010, one quarter later than originally planned. And to be clear, these estimates exclude any contribution from our proposed alliance with EXCO in the USA, which has still to be completed.

Annualised growth in production in 2009 is expected to be between 6-7%. Our long-term growth target remains 6-8% per annum, as we set out at our Strategy presentation back in February.

In North Africa, we made good progress with a number of major new projects. In Tunisia, gas was introduced earlier this month into the BG Group-operated Hasdrubal facilities. Commercial production is expected to follow in August. In Egypt, the West Delta Deep Marine Phase V project was successfully brought onstream and work advanced on the Sequoia development, due onstream later this year.

In Brazil too, momentum is gathering on a number of fronts, with rapid progress being made towards both the commercialisation of BG Group's very material reserves there, as well as with further exploration and appraisal.

The Floating Production Storage and Offloading Vessel for the 100 000 barrels per day first development phase of Tupi is now around one third complete and on schedule to commence production at the end of 2010. This means first production from permanent facilities will arrive just four years after the initial exploration success, so achieving our accelerated development objective. And there are more such accelerated developments to come.

At Iara and Guara the FPSOs continue to be fast tracked. The capacity of each has been increased by 20% from 100 000 to 120 000 barrels oil equivalent per day and tendering for their supply is underway. We are thus making good progress towards the sanction of these two material new projects by the end of 2009.

Meanwhile, the Extended Well Test on Tupi has proceeded very favourably with excellent flow rates, constrained by facilities to an average of some 14 000 barrels a day, with peak production so far approaching 15 000 barrels a day.

The test on Tupi has been temporarily suspended to allow the precautionary changing out of the subsea Christmas Tree following a manufacturer's alert relating to bolt materials. There are no technology implications for the Tupi development.

On the drilling front, Iracema, a long distance step-out appraisal well 33 kilometres from the original Tupi discovery, was successful and penetrated a light oil bearing reservoir section. A new well on north east Tupi is also currently drilling.

Exploration wells Abare West on BM-S-9 and Corcovado 2 on BM-S-52 are also currently drilling, both of which are expected to reach target depth in the third quarter. The spudding of the BM-S-50 exploration prospect Sagittario is also planned for later in the year.

So a lot of activity in Brazil during the quarter and excellent progress too, with FPSO construction, major facilities and materials tendering and ordering, well testing, six drilling rigs operating in BG Group's licences and further exploration success. This rapid progress is made possible by the continued strong alignment between partners, operator Petrobras, and the Brazilian government, to advance the development of these very substantial pre-salt resources.

Turning now to the US, in June we announced our new alliance with EXCO Resources to exploit shale gas opportunities in east Texas and north Louisiana, principally in the prolific areas of the Haynesville shale. This acquisition brings material new resources and supply to the Group's existing US gas marketing business at a competitive price and in a prime location. The deal is conditional on a further agreement to acquire a share in EXCO's related and complementary gas gathering and transportation assets and completion is expected in the third quarter.

Shale gas will be an increasingly important element of the US supply mix. These resources, which we believe are at the low end of the shale gas cost curve, have substantial upside potential and fit with our existing US activities and infrastructure.

Further progress was made with the globalisation of our LNG business. In the Atlantic Basin, the first LNG cargo was received at the Dragon LNG regasification terminal in Wales. In the Pacific Basin, the GNL Quintero regasification terminal in Chile also received its first cargo. In Asia, we signed an agreement with China National Offshore Oil Corporation, focused on our Queensland Curtis LNG project in Australia. This agreement underpins our plans for a two train first phase of development of the QCLNG project.

LNG supply contracts to China, Singapore and Chile are expected to account for up to 8.3 million tonnes of LNG demand per annum. This represents further solid progress with commercialising our substantial resource base, through successfully winning new markets in the currently highly competitive LNG business environment.

And finally, alongside our growing investment programme, we are pleased to announce a 20% increase in our interim dividend.

In summary then:

- Exploration & Production volumes increased 7% year-on-year;
- Gas has been introduced to our new Hasdrubal facilities in Tunisia and commissioning is now underway;
- In Egypt, the WDDM Phase V came on stream and the Sequoia development made progress;
- The Dragon LNG and GNL Quintero regasification terminals have received their first LNG;
- Excellent flow rates were achieved from the Tupi Extended Well Test in Brazil;
- For Iara and Guar: planned capacity up 20% and good progress towards sanction by the end of 2009;
- Success at Iracema – a step appraisal well 33 kilometres from Tupi
- In the Pacific, an agreement with CNOOC for the 20 year sale of 3.6 mtpa from QCLNG;
- In the USA, an alliance with EXCO Resources to develop shale gas in Louisiana and Texas;
- And finally, a 20% increase in our interim dividend.

So an active second quarter with a resilient performance and rapid progress in the development of our business.

And now over to Ashley for a more detailed look at the financials.

Ashley Almanza, Chief Financial Officer

Thank you Frank, and good afternoon ladies and gentlemen.

We'll start with the E&P segment.

Production volumes in the quarter were 7% higher reflecting the benefit of investments in Tunisia, Egypt and across the Group. As we are now more than half way through the year we have good line of sight on the outlook for full year production.

As usual, our shutdown and maintenance programme is concentrated in the third quarter. In the second half of the year, we will continue to see the benefits of our investment programme, with increased production from Hasdrubal, Miskar, West Delta Deep and Sequoia. And as Frank has mentioned, this new production, combined with production efficiency gains across the portfolio, will see our production rate rise to an average of over 700 000 barrels per day in the fourth quarter.

Turning back to the second quarter; our international gas price realisations were 19% lower in sterling terms and 39% in dollar terms, principally due to two effects: lower Henry Hub prices and the lagged effect of lower oil prices.

Lower Henry Hub prices reduced net-backs in Egypt and Trinidad. In Thailand and Tunisia, where the gas price is indexed to oil with a 6-9 month lag, the fall in oil prices in 2008 fed through to gas prices during the second quarter of this year.

As expected, our UK gas realisations were around 36 pence per therm and our guidance for contract prices for the gas year ended 30 September is unchanged at around 55 pence per therm. We'll provide details on our UK contract prices for the next gas year when we report our third quarter results. Continuing with the trend in recent years, you can expect our UK contract prices to be more closely related to market prices at the UK national balancing point

Unit operating costs were \$5.42 per barrel for the quarter, in line with the first quarter. Our full year guidance remains around \$5.90 per barrel, taking into account the summer maintenance season.

The exploration charge increased by £36 million to £130 million, which includes a £52m non-recurring charge to write off of historical exploration costs. Given our desire to maintain focus in appraising and developing our strong prospect inventory, we have written off a small number of marginal prospects. We continue to expect our gross exploration expenditure for the full year to be around £1.1 billion and, including the non-recurring £52 million charge, about £550 million of this is expected to be expensed.

Turning now to the LNG segment.

Against a background of a 66% drop in Henry Hub prices, our shipping and marketing business delivered a good performance, with operating profit down 20% to £275 million. This result reflects the benefit of our term sales and hedging programmes plus the positive impact of the stronger dollar.

In our liquefaction business, another strong performance at Egyptian LNG, contributed to a £17 million rise in profits.

For the LNG segment as a whole, operating profits fell 15% to £311 million.

The outlook for the LNG segment is in line with expectations and our profit guidance remains unchanged at between £1.4 and £1.5 billion for 2009, and £1.2 to £1.3 billion for 2010. The guidance for both years is based upon an exchange rate of \$1.50 to the pound.

Total Operating Profit in Transmission and Distribution more than doubled to £127 million. At Comgás, although volumes were impacted by lower industrial demand and the greater availability of hydro-electric power, we continued to recover gas costs incurred in prior periods and operating profit rose strongly to £114 million for the quarter and £184 million for the half. The outlook for the second half of 2009 is in line with market expectations.

The regulator finalised the Comgás tariff review in the second quarter. As expected, a schedule of lower tariff margins has been fixed for the forthcoming five-year period. This should ensure that gas continues to be a highly competitive fuel in the Comgás concession area which, in turn, supports the continued growth of Comgás.

In the Power segment, Total Operating Profit of £49 million reflected increased profits from our US power business due to lower gas costs and the timing of power sales.

For the Group as a whole, Total Operating Profit decreased by 32% to £972 million and earnings per share fell 37% to 15.1 pence per share.

Cash generated from operations fell by 38% to £1 billion. Working capital increased by £258 million, primarily due to a higher level of working capital in our LNG business and

in our oil receivables. Capital investment was £1.2 billion in the quarter and £2.5 billion for the half year. Our full year guidance, including acquisitions, is £5.4 billion.

In line with our established policy, the Board has approved an interim dividend of 5.62 pence per share, which is half of the 2008 full year dividend and a 20% increase on last year's interim dividend.

In summary then, the Group delivered a strong performance for the first 6 months in the face of significantly reduced commodity prices and is well positioned to deliver a strong performance for the full year. That concludes my remarks and now Frank and I will be pleased to take your questions.

Q&As

Frank Chapman, Chief Executive

Thank you Ashley, and we are now happy to take your questions. Please could you state your name and company when asking a question? Thank you.

Theepan Jothilingam,

Morgan Stanley:

Afternoon gents, two questions actually, firstly just on US shale, I was just wondering if you could give a little bit of colour in terms of the timing into the entry to the US shale business? I mean clearly there's the logic there but I was wondering why you chose 2009 rather than an earlier move and why EXCO?

Secondly it was very sort of notable, you haven't really commented on the progress in Australia, so I was wondering how the drilling programme there goes and how you're sort of converting the resource into reserves and then whether you're on track for a FID towards the end of this year or early into next? Thank you.

Frank Chapman:

Yes, Theepan let me just take the last one first. Progress in Australia is going extremely well. I think that we will be somewhere around 5 trillion

cubic feet of 2P reserves established by the turn of the year. The programme is going very well indeed. And we are still on track for a sanction of these developments next year.

In terms of US shale gas, as I said in my remarks we believe that this is going to be an increasingly important part of the supply mix in the US. Obviously not all shale gas is created equal. Some of this stuff is quite expensive. We have taken a long time to look at this and have entered with EXCO because it has in its portfolio assets in the Haynesville which we believe are at the extreme left hand end of the cost curve, the low end of the cost curve.

Some of the well initials there have been 20 to 25 million standard cubic feet a day, so extremely good acreage in their portfolio. And of course this fits with our existing US business and represents in our view a very good opportunity to make economic investments.

The timing, well it's driven by two things, one we've been busy for quite some time trying to understand this area in sufficient detail to know enough about it to make an investment decision. And secondly of course the economic crisis has put pressure on some of the existing players and has made available more opportunity than might otherwise have been the case. So preparedness from BG one factor and simply the opportunity availability another factor.

But I think it's really important to emphasise that we have a view that the US market is going to need shale gas, it will be a component. And if

you're sitting on assets which are the lowest cost assets to develop in this market, clearly they are going to enjoy margins which are fixed actually by the marginal shale gas supplier, which will be at some significantly higher unit cost than we believe our assets will be.

So that's shale gas and progress in Australia.

Theepan Jothilingam,
Morgan Stanley:

Frank, can I just ask a follow up question? Do you think that the position now you've got in EXCO is sufficient in the US or should we expect a further move?

Frank Chapman:

Well we've got 2.5 tcf which is getting on for 500 million barrels BG net. I think there's a lot more potential in this acreage and our first priority will be drilling appraisal wells and making sure that we understand what we've got and that we're accessing the potential there. So something you know of this scale is obviously quite material.

Theepan Jothilingam,
Morgan Stanley:

Great thank you.

Iain Reid,
Macquarie:

Good afternoon gentlemen, could I ask a couple of questions on Brazil and one on gas demand. You've obviously had to curtail the EWT on Tupi, but I wonder given the information you have so far what that's told you about potential flow rates that you think you'll be able to get out of this field when the wells are unconstrained, or at least hooked up to the FPSO?

And I also wonder what you now feel about the previous statements you've said about oil in place. You've drilled obviously a lot more wells now on the field and you've conducted a test. So I wonder whether that has made you feel more optimistic about oil in place and maybe also recovery factors, if you want to talk about that?

Secondly, you've upgraded the capacity of the Iara and Guara FPSOs I wonder what was the driver for that? Was it some contracting reason or was it driven by kind of reservoir production issues?

And lastly, you talked - or at least you mentioned Frank something about mitigation of demand reduction. Could you explain exactly what that means and what you're doing there?

Frank Chapman:

Okay, so there's a quite a few questions there. In Brazil, let me tell you that we have been producing around about 14,000 barrels a day on average; we've had up to 15,000 barrels a day. It is constrained by gas handling and gas flaring permits. So this is not a reservoir constraint or indeed a surface facilities production constraint other than the gas side constraint. So these wells can do more.

What we're seeing I think we're regarding as an excellent result. We won't be announcing any further adjustments to any of these estimates until we've got further with this extended well test. It is scheduled to go on for 15 months. And actually that has only just started. So what we're able to report is that we are absolutely happy with what we're seeing so far, absolutely performing as we expected. But we won't really know what the

extended well test reveals until we get much further down the road.

Having said that you know the extended well test really is to look at how we believe the reservoir will perform longer term and to enable us to think about the timing for example of water injection, the effectiveness of gas injection for example and to decide quite how we will phase that in the development. This extended well test is not expected to reveal information that would for example make the development uneconomic. I don't think it's a primary determinant of the economics of the development rather more information that will enable us to optimise the development - the shape of the development and the sequence.

So we won't be saying anything more at the moment Iain about recovery factors or in place volumes.

The increase in the capacity of Guara and Iara, what we're doing in both these facilities, we've had a little bit more time to think about them. We want to develop the facilities themselves to be capable of handling any of the various reservoir fluids and pressure regimes that we've seen. And these are not identical across all the fields. So these next ones will be a little more complex in their - when I say complex they'll have a little more flexibility built into them such that they can be deployed in the place which will yield the best economics.

So as we continue our drilling and appraisal, for example we've just drilled Iracema, it maybe more beneficial for example to deploy one of these

vessels at Iracema if that means that we can make efficiencies in the development of the gas gathering infrastructure. That would be an example.

So as part of that whole exercise we had a look at capacity and we decided that these units would be - with some efficiency expanded to 120. So that's the story there.

Then you had a question about gas demand and the mitigations. And I think really what we're talking about here is that within BG, as part of our performance management process we have had established over quite a period a programme of business improvement. And this really is literally hundreds of initiatives that go right across the Group.

And what we are trying to do with these initiatives is to reduce the technical and commercial bottlenecks in each and every asset we've got. And typically these include things like infill drilling, well stimulation, production optimisation, de-bottlenecking - treatment facilities, removing commercial constraints, developing new market opportunities. There's this whole thing to de-bottleneck each and every production chain.

And good examples of mitigation in this particular case would be Karachaganak where we've worked - where we've seen some decline in demand on the gas side and so we've been working extremely hard to optimise the well performance, such that we get more liquid rich wells, getting more through by de-bottlenecking surface facilities, more through the export side, even though the gas side is

constrained. And that work has been extremely successful and we've produced notwithstanding the significant constraints on the gas side we've been getting above budget volumes through the liquid side. So that would be one example.

We're trying to squeeze as much gas as possible through Atlantic LNG and we've been really quite successful with that, because domestic demand is down, we're effectively substituting export markets for constrained domestic markets and we're trying to do the same at ELNG. So we take these initiatives together and we put those alongside - those other initiatives which are really helping us to mitigate some of the weaker demand picture. And if we put them alongside the general picture of business improvements and the new projects that are coming on, those are the things which enable us to get a reasonable handle on what we think is going to happen in the second half of the year.

A long story but it is a matter of - it's not rocket science it's a matter of a lot of detailed work. And some big examples, but many hundreds of much smaller examples.

Iain Reid,
Macquarie:

Okay, Frank thanks a lot.

Paul Spedding,
HSBC:

Good afternoon. Firstly just quickly on Corcovado 1 can you please lay that story to rest, as there is obviously a fair bit of confusion out there on the various newspapers and newswires. And secondly a general question on LNG demand and LNG supply. Are you seeing any signs of recovery in gas demand as we go through the third quarter?

And also looking at your competitors around the world are you seeing any signs of them curtailing output from LNG schemes?

Frank Chapman:

Let me take - I'll ask Ashley to comment on the LNG market in a moment. Corcovado 1, I mean just to take a couple of minutes here. The situation in Brazil is if wells encounter hydrocarbons operators are required to report that to the ANP. And when reporting that, one has to have two independent forms of evidence and in the case of Corcovado 1, the hydrocarbons, physical hydrocarbons were evident as well as evidence of hydrocarbons on the logs. And therefore we had two independent sources of evidence and therefore we reported as required to the ANP that we had encountered hydrocarbons and they duly posted that their website.

Now, we encountered when we drilled this well significantly higher pressures than we'd expected. We could manage those pressures because there was over design in the casing scheme. But we saw higher pressures than expected. And that meant that we were unable to test the well at that time. And what we've done is we've ordered a string of 7 inch casing, we've gone away to drill Corcovado 2, the casing is on order. When we finish Corcovado 2, we're going to go back, install a 7 inch casing string and test the well. That's our plan for the moment.

And clearly you know we wouldn't do this ordering of the casing and plan to go back and test it without a good reason. You've seen overnight I presume the press release from Petrobras and I think you know the information that we're giving

you and the information that Petrobras is announcing is quite consistent. And I think that's probably a more reliable source of information than some of these quite speculative press reports.

Ashley Almanza:

Paul, on LNG there is no change really to our view on the short term outlook market. There is obviously lots of new supply coming to the market. There is also no change to our guidance. So our term sales and hedging programme is working as designed.

In the longer term we remain confident that there will be growing demand again for LNG and as Frank mentioned in his earlier comments we've been out securing markets. Which is hard evidence of demand as you go further out, you know beyond this immediate lump of new supply.

Frank Chapman:

You know the long term view that we have is that the LNG market globally is going to grow. I think we said in February 150 million tonnes of new demand out to 2020. We don't need very much of that to satisfy the development quantities that are coming out of our new projects. But we have been as Ashley says, very, very successful. We said we felt we had specific sources of advantage that would enable us to secure market and that's exactly what we've been doing. And I think that's a very good sign that we're making strong progress with the commercialisation of a very significant resource base.

Paul Spedding,
HSBC:

Thanks,

Oswald Clint,

Sanford Bernstein:

Hi, good afternoon, two questions I guess LNG related. The first one - you talked about some of your gas prices and the links with oil prices. I wonder if you could perhaps tell us how the Chilean LNG price is set, is it also with oil prices and what type of lag, or what sort of prices you're getting there and where you would expect to be sourcing cargoes for that commitment through the rest of '09 and next year?

The second question was just I noticed the change on the Singapore agreement. I was interested to know if anything material had changed within that contract in terms of pricing or just anything else on that?

Frank Chapman:

Okay on Singapore the government is now standing in the shoes of the previously expected consortium. But I am able to confirm that there have been no changes to the contract as BG sees it. BG being both the developer in Singapore of the gas market, the aggregator and the supplier to a third party owned LNG terminal. Sorry, the regasification facilities will be owned by a third party, we'll have the market on one side and the supplier on the other. So that structure is unchanged by the change in governorship of the regas facilities.

In terms of gas prices, how they work, where we're sourcing cargoes from Chile I'm sorry you won't be surprised Oswald that I'm not going to tell you that. Because all of these arrangements that we have, all of the commercial arrangements serving our LNG contracts both on the supply side and the

market side, how many cargos are going over what period, where they're coming from is just too commercially sensitive to share and it's not in our interests or our shareholders interests to divulge that. So I'm afraid I'm going to have to - one more time, once again disappoint on not answering that question.

Oswald Clint,
Sanford Bernstein:

Okay thank you very much.

Gordon Gray,
Collins Stewart:

Good afternoon, just a quick question on Norway. You've got a very active programme of exploration there and the Bream appraisal this year. I'm wondering if there's anything you can tell us to update us a bit on how things are going?

Frank Chapman:

Yeah, I mean the Bream appraisal; we drilled a Bream appraisal well which was successful. And we have side tracked that well into a separate well bore which has also been successful and we're currently running guns actually right now and expect to perforate and perform a flow test in the next - well imminently.

The real star of the show I think in Norway is Jordbaer which is a completely new play in the North Tampen area. And that has found a new sandstone reservoir called the Cook. And the Cook is a new play as I say and quite prolific. The scale of this discovery is to be appraised so we've not said anything about volumes. But the production capacity of this reservoir is excellent and BG has a number of look alike structures in this play in and around the current licenses.

So it's too early to say exactly where this is going to lead but we have been reprioritising our expenditure on exploration to focus on intensification during the latter part of this year and through the next two years and intensification of exploration aimed at Cook.

So that's Norway.

Gordon Gray,
Collins Stewart:

That's great thanks.

Frank Chapman:

Oh, Mandarin, yes of course don't let me forget to mention that Mandarin will spud later this year. The rig is currently undergoing modifications to do that work and towards the back end of this year we will be spudding Mandarin, which is quite a significant prospect that we're going to explore.

Gordon Gray,
Collins Stewart:

Great.

Michele della Vigna
Goldman Sachs:

Hi, I just had a question on LNG if I just apply your guidance I see a pretty sharp reduction in EBIT in the second half of the year. I was wondering if this is due to the fact that your coverage of hedging is lower in the second half than it was in the first half?

Ashley Almanza:

The answer is no, I mean of course as we go through the programme we are effectively utilising or realising the hedge. So it's more a function of the mix of contracts and the supply arrangements through the second half.

Jon Rigby,

UBS:

Hi, two questions. The first just going back to your comments on UK gas prices, it's clearly evident that NBP has been under a lot of pressure in this gas year. Should we just use that as a guide to where your contract pricing will go or do you have any wiggle room around it in that there's other issues to be priced in and we shouldn't just take it as a direct read across?

The second is just to look at Corcovado. I think you've talked in the past that it's in shallower water and therefore might be easier to develop. As we move forward with this, is it something that you still think would be able to get slotted in to any development plan in the Santos even if you know lara, Guara, Tupi are all going full steam ahead, i.e. could it be done concurrently or would it have to take - you know if it's successful its place in the queue? Thanks.

Frank Chapman:

Well of course the stack, I'm going to ask Ashley to comment on UK gas prices. But on Corcovado generally I guess the way we're looking at this is that we want to develop FPSOs that are capable of handling a range of reservoir fluids, a range of - as I say gas ratios such that we have some degree of flexibility, to reprioritise, to optimise the overall development.

So what I imagine is that this stack will be shuffled and reshuffled. It won't cause such a big problem for Petrobras and ourselves, but it may cause some tensions of course with some of the other members of the consortium as we - well not really tensions but we'll have to get everyone lined up on that.

But I expect that stack of and the sequence of projects to be developed will be reordered from time to time. I think we are of the mind that we are in the fortunate position that the best discoveries that have been made in the pre-sort are the discoveries that BG and Petrobras as participating in. And that's not magic that just happens to be how it has come out. And that is I think evident from the fact that the projects we're engaged with Petrobras on are the projects that are getting the priority and getting the funding.

So I think these things will be reordered from time to time. As I've said before the great thing about this whole play is that we're going to do the same sorts of things over and over and over again. You know we're going to have ten FPSOs that all look similar and subsurface facilities and risers all that are all going to look similar. We're going to drill lots and lots of wells, 300 wells that are all the same. And the opportunity is there of course to leverage the learning that one acquires going through this process to make the next one even better.

So the idea of when you develop a Corcovado or when you develop Carioca are whatever it is, you're not starting with a blank sheet of paper. You're actually just taking the last thing you did and saying what do I need to adjust here and putting it in?

So I think that as we're learning this is going to get easier as we go along. I think easier and easier. And I really am very pleased with the way that the whole development process is progressing. Four

years from exploration well to first production in 2300 metres of water now that's quite an achievement. And you know the idea that by the end of 2012 we could have 340 000 barrels on stream well that's cracking on.

So people tend to think they've made all these discoveries, we have to wait forever and a day to see it coming through. I think the realisation is beginning to dawn on people that actually it's very material and it's actually quite near term. It's happening.

So I don't know whether Corcovado is going to be high on the pecking order or number five in line, or where it's going to be. We have to go back of course and test this well. But the possibilities for reordering things are definitely being built into the way that we're approaching facilities development.

Ashley Almanza:

Jon, on UK gas price, we'll continue to sell a significant proportion of our UK gas under contract, so as to avoid being in a position where we have to sell all of our volumes in the front month or in the short end of the market.

However, those contracts will you know in line with the trend that we've seen over recent years be increasingly linked to NBP. So I think in the absence of longer term guidance NBP is a reasonable reference point going further out.

Jon Rigby,

UBS:

And that would be the NBP prevailing at the time that you're supplying the volumes or some sort of lagged NBP calculation or a bit of both?

Ashley Almanza:

A bit of both.

Jon Rigby,

UBS:

All right okay, thanks.

Lucy Haskins,

Barclays Capital:

Hi Frank and Ashley, could I just follow on on the Brazilian questions? So this sort of 20% uplift in terms of the capacity is more about the flexibility for the facilities rather than necessarily a comment in terms of the ultimate productive capacity for Iara and Guara?

Frank Chapman:

Not really, clearly we've said three to four billion barrels for Iara. That's going to need several FPSOs to develop those resources in time. The 20% uplift really occurs because we've sat back and reflected on what's practicable, to get on board here, how do we want those facilities, what sort of level of flexibility do we want incorporated in those facilities. And as a combination of all of these things we've come up with a new standard sort of design if you like that we want to progress with and that's 20% bigger.

Clearly we wouldn't be putting a unit 20% bigger in a place where we didn't think the resources were present. But no I think that's really it. It's an opportunity to do 20% more on two projects which is progress. And you know we're going to build the flexibility. I think that later on we may end up building FPSOs which are considerably bigger and

that's the sort of process that we continue to go through as we develop our thinking about later phases.

Lucy Haskins,
Barclays Capital:

Could I ask the sort of bringing forward of the sanction, how does that change the CAPEX profile for next year?

Frank Chapman:

Well I think that we - we're going to be committing to FPSOs quite soon I think for Iara and Guara. And we've made allowances in our capital programme that we announced earlier in the year, in February we talked about four billion times four, 16 billion. And that has been adjusted of course more recently because of some of the acquisitions we've made in the meantime. But essentially that's in the programme.

Ashley Almanza:

And the FPSOs will be leased.

Frank Chapman:

The first FPSOs will be leased, that's simply so we can get this thing out of the blocks and get it started. The strategy for how we'll provide facilities in the longer term is something which is under review.

Ashley Almanza:

No change to the CAPEX Lucy.

Lucy Haskins,
Barclays Capital:

In terms of the aggregate is there a bit more front end loading or not?

Ashley Almanza:

At the margin there may be - you know long lead items and so on. But we've effectively built in the CAPEX profile for these developments.

Lucy Haskins,
Barclays Capital:

Thank you.

Mark Iannotti,
Bank of America Merrill Lynch:

Afternoon gentlemen there is going to be a couple of different questions on Brazil. You know your LNG strategy in the past has clearly demonstrated that being integrated and involved in all aspects of the value chain can yield higher returns. When I look at what you're doing in the US I do struggle to see how being involved in regasification and in shale gas and your quite extensive now investment in power, how being involved in these three quite different gas businesses can yield anything greater than the individual parts. Can you maybe just explain how you see this US gas business developing and how being involved in all these aspect of this gas chain can yield higher returns than choosing which spots you want to be invested in?

And maybe a second question, one of your biggest competitors in LNG has just announced that they're pushing ahead with a floating LNG option. I'm just interested in your own thinking on the robustness generally of floating LNG. And could it form part of your thinking in any parts of the world in the future?

Frank Chapman:

I think on the first question Marc, one has to recognise that when one has gone through the process of building a business interest in a country and building a successful business in the country that is quite - represents quite an investment in itself.

And you know the whole process starts not necessarily with the mindset of the LNG business which does require integration you are quite right in order to make exceptional returns. But on a play like shale gas in the US, one starts with having infrastructure in terms of human capital, operating experience and so on in that environment and then saying I'm here on the ground, I've got all of this capability here, I'm active in this market are there other investments that are fundamentally on a standalone basis economic? That's the first question. And the next question is and if I have them are there opportunities as well to make incremental gains over the top of that fundamentally sound investment?

So if I look at shale gas I think this is a great opportunity, it is going to be – it is today the most economic in our view shale gas opportunity in the US. The price of gas in the US is going to be fixed at the margin by the marginal shale gas supplier somewhere higher up on the cost curve and therefore the economics I think for these developments of ours will be good. And there has been quite a lot written about this recently - quite a bit of it we wouldn't disagree with, which underscores the prolific nature of the Haynesville.

And so the logic is really driven by the fact that we're on the ground. It is the world's largest most liquid gas market. It has to become either an importer or develop more indigenous supply. That represents opportunity. Can we get assets at the advantaged end of the cost curve, answer yes, why wouldn't you?

Mark Iannotti,

Bank of America Merrill Lynch: Okay, so we should think of this as a simple resource chase rather than anything that you're looking to do in an integrated basis around your other US gas businesses to uplift the earnings and margins?

Frank Chapman: These things have to be fundamentally economic as a standalone venture. This is the way we set the LNG business up. Don't forget we set the LNG business up based on a price into the US of 2.50 to 3.50, making it fundamentally economic. We then thought the arbitrage opportunities would provide cream on the cake. We've learnt a lot about how to do that and we've made that cream a bit thicker than we'd anticipated initially.

But underneath all of this every individual LNG investment is economic in its own right. And the same applies to the shale gas opportunity.

Now as I said earlier on, it's 500 million barrels that's not to be sniffed at in terms of a resource play and maybe it gets to be from the existing resource space significantly bigger. So it's not immaterial in the overall scheme of things. And we believe it will deliver solid economics.

Mark Iannotti,

Bank of America Merrill Lynch: Thanks,

Ashley Almanza: Floating LNG?

Frank Chapman: Floating LNG, we've had our own project going for quite some time. I think that - I was asked the question earlier on; does it yield better economics?

And I think the answer is maybe but for a specific play.

I mean in terms of carbon conversion efficiency it's probably still better where possible to use an onshore based facilities using more traditional processes. But floating LNG has a role to play for isolated, remote and perhaps smaller accumulations which otherwise would go undeveloped.

And we have our own project in BG that's been going for some years looking at floating LNG and there are certain places around the world, Brazil and Trinidad to name two where one could see deployment of this technology at some point, potentially.

Mark Iannotti,

Bank of America Merrill Lynch:

Okay, great thanks.

Michael Alford,

Nomura:

Hello good afternoon guys. Can I ask one follow up question please on your comments around EXCO and the economics? Could you maybe give a little bit more indication as to how much CAPEX you're expecting to invest over the next couple of years so incorporating obviously the carry that you've agreed to for EXCO's share? Could you give maybe a bit of colour as to what CAPEX we could expect from those assets please? Thanks.

Ashley Almanza:

It's in total, including the acquisition cost, about 1.5 billion. And I think really, as Frank has indicated, that our first priority is to make progress with the appraisal programme and the pace of that

programme will determine what follow on CAPEX there is beyond that.

Michael Alsford,

Nomura:

Okay great. Thanks very much.

Andrew Whittock,

Oriel Securities:

Yes good morning gentlemen, or afternoon. Just a follow up on that actually before I ask a more general question on CAPEX. Did I just hear you say \$1.5 billion including the acquisition cost?

Ashley Almanza:

But excluding the carry. Yeah.

Andrew Whittock,

Oriel Securities:

So including the 1 point something billion dollar acquisition cost, but excluding the carry.

Frank Chapman:

Yeah I think the acquisition cost is made up of 600 million plus 400 million carry. And the ongoing programme in the future, we're - BG's capital contribution as a 50/50 partner will be 1.5 billion.

(For clarification: The EXCO acquisition comprises USD 655 million acquisition cost, USD 400 million carry, capex of about USD 1.5 billion out to 2012 and USD 249 million for midstream assets)

Andrew Whittock,

Oriel Securities:

Okay. That's what I thought. My question was going to be that I couldn't help but noticing in the statement today that you've stopped disclosing quarterly the CAPEX by country in your upstream business, which I was a bit disappointed about I have to admit. But looking at your guidance for organic CAPEX this year it seems that you're going to spend about £2 billion in the second half. Given the progress you've made with most of the

developments that I'm aware of at the moment, I just wondered what that 2 billion in the second half was going to be spent on.

Ashley Almanza: It's across a range of projects Andrew that we outlined in February. Of course where a lot of our capital expenditure is being directed towards exploration and appraisal.

Frank Chapman: It's a lot actually - the exploration programme is tilted substantially to the second half of the year. It's a big programme; it's over £1 billion. The majority of that is occurring in the second half of the year. We've got ongoing major expenditure in projects such as Sequoia. A lot of money being spent there. And quite active infill programmes around the world, a lot of drilling going on in the UK, mentioned earlier on Bolivia, Tunisia itself in Miskar, more drilling offshore Egypt, we've got LNG ships. It's not difficult to spend the money, spending it wisely of course is always a challenge that we face.

Andrew Whittock,
Oriental Securities: Okay thanks for that.

Colin Smith,
ICAP Securities: Yes that would be Colin Smith. Afternoon gentlemen. Couple of questions as well. As I recall production growth this year was partly predicated on start-up of domestic volumes in Trinidad, and I think you mentioned earlier that domestic demand was a little bit weak in Trinidad. Could you just tell us where that stands at the moment because I think that was 220 million cubic feet a day net to you?

Could you also give us a flavour of just how much of your upstream production is exposed to Henry Hub gas pricing?

And finally a note on the Iracema comment on the quarterly report. You call it a step out appraisal which looks like it links it into Tupi a little bit more than the initial announcement did, and I wonder if you could just update us with what is going on with - rather testing Iracema and your thoughts about how that may be connected in with Tupi.

Frank Chapman:

So we've got the Trinidad question, Henry Hub.

Andrew Whittock,
Oriental Securities:

And Iracema.

Frank Chapman:

Exposure and Iracema. Well look Trinidad, this is a story of measures that we're taking to mitigate the effects of weaker demand in certain markets. And I reckon that over the year, and I'm speaking now very approximate, we will probably end up being short on demand - short on total production relative to our plans in Trinidad of about 5%.

But we will be pushing a lot more gas through ALNG, so you know the size of the shrinkage of domestic demand is significantly greater than that 5% because we're recovering a lot by squeezing it through. But the overall production effect has been substantially mitigated and now will be 4 or 5% down relative to our original plans; I'm speaking now about Trinidad alone.

Iracema, the point we're making here is that we've gone off 33 kilometres and we've drilled a hole and we've intersected the same hydrocarbon bearing

section. And that's got to be good news. One has lots of models and can speculate about the extent of a given hydrocarbon trap, but the proof of the pudding is going and drilling wells that are quite distant from the original discovery and proving that actually the hydrocarbons are there.

So the relevance here is to say we've gone off way over there, we drilled a well and we've got hydrocarbons. And I think that's really good, you know that's positive news.

Henry Hub exposure?

Ashley Almanza:

It's principally Egypt and Trinidad and that represents about 30%.

Robert Kessler,
Simmons & Company:

Hi thank you. Just a quick clarification on the relative economics of the shale gas. You mentioned being at the lower end of the cost curve in the US relative to other shale gas opportunities which I think makes a great deal of sense, particularly when the full cost curve is utilised. But obviously in today's environment it's expected that not that full curve will be realised.

And just I'm curious how you would stack up the shale in the EXCO assets relative to say LNG. You threw out a number of I think 2.50 to 3.50. I wanted to clarify whether that would include the EXCO properties and again how those would stack up versus your base load LNG.

Frank Chapman:

No I think the \$2.50, \$3.50 was I was just recalling the basis upon which we set up the LNG business, the economics of the fundamental proposition to

bring LNG into the US. I think the idea here is quite a simple one. Does one believe that it's possible for LNG to fill all of the supply gap that's going to build as the current US supply portfolio matures?

Most people would say that it's quite difficult to imagine any scenario where as we work back towards recovery, that all of the future demand growth and all of the decline in the existing supply base can be satisfied by importing LNG. It's pretty difficult actually to come up with a scenario where that is the case. If that is the case where is the gas going to come from? And our view is that under pretty much every scenario which we can dream up shale gas has to be part of the supply mix.

Now if that's the case your only big question is at what level shale gas is going to come in. Even if shale gas is more expensive than some of the LNG, you know some of the LNG could be cheaper, Trinidadian LNG is probably going to be cheaper than - don't know about Haynesville it might be about the same price but anyway it could be cheaper. The only question really to decide is how much of the shale gas gets developed and which projects are going to be the marginal suppliers into this market, because those marginal shale gas projects are likely to fix the market clearing price for gas. They are going to fix in our view the North American gas price. Now if your project is some distance removed to the left because it enjoys a much lower cost structure then that sounds like a good place to be.

So that's the equation really that we're looking at. It's the relative positioning of Haynesville relative to

the cost structure of other shale gas projects.
Because LNG in our view can't meet all of the
growing demand in the future and replace declining
supplies where they're coming from today.

Robert Kessler,
Simmons & Company:

Sure I think that logic...

Frank Chapman:

That's the logic. It's not rocket science but that's
the fundamental logic.

Robert Kessler,
Simmons & Company:

Any chance I could get you to put a netback
requirement on the EXCO assets?

Frank Chapman:

I don't think we're going to do that for you today.
But we're pretty confident that by some distance
this is at the advantaged end of the cost curve.
You know when you have well initials of 20 to 25
million standard cubic feet a day, that's pretty good
performance.

Robert Kessler,
Simmons & Company:

Yeah. All right thanks very much.

Peter Bassett,
Hanson Westhouse:

Good afternoon gentlemen. We haven't spoken
before; I'm a colleague of Malcolm Graham-Wood.
I note your 5.4 billion sterling CAPEX forecast for
the full year and new borrowings in the cash flow
statement. And the very high CAPEX will follow
the very exciting news on Brazil and the US. I just
wondered whether you saw a rising debt equity
ratio in the next few years, and whether this would
affect the growth in dividends as well in the next
couple of years.

Ashley Almanza: Yes I think that obviously that's going to depend very much upon oil and gas prices. And we set out in our statement the degree to which our business is sensitive to changes in oil and gas prices. But certainly currently it's our view that we can fund the capital expenditure programme and continue to grow the dividend in line with underlying earnings growth, because whilst the capital expenditure programme is as you rightly say substantial, we're also bringing on new projects through this period which will clearly contribute to operating cash flow as we go along.

Peter Bassett,
Hanson Westhouse: Thank you.

David Cline,
RBS: Good afternoon. Two questions if I may. Firstly on Comgas. You mentioned in your opening remarks a transition I think to a lower margin regime. I wonder if you could say a few more words about that.

Secondly on the hedging in shipping and marketing. You give an explicit guidance out to 2010. Is it reasonable to assume that there is a significant amount of additional hedging in more distant years or is 2010 as far as it goes?

Ashley Almanza: Well let me first of all take the Comgas question. Comgas in common with most regulated utilities faces a periodic review of its service tariff, tariff margin and in the case of Comgas this occurs every five years. And the regulator sits down with the company and we agree - fix a tariff for the next five years.

Again in common with other regulatory environments we anticipate in our business plans the regulator will look to see as the business gets more and more scale, will look to see that some of the efficiencies that are achieved are shared with consumers. So that's anticipated in our investment case. And indeed that's what's happened in this regulatory review.

On aggregate or on average we are seeking to achieve efficiencies which will enable us to reduce the tariff margin by between 9 and 10% over the next five years. So that's the story on Comgas.

On LNG we've set out our arrangements out to the end of 2010 as you say. And at this stage we've got nothing further to add to that. Be happy to give you an update in February when we'll have more to say possibly.

Neill Morton,
MF Global:

Thank you, good afternoon. Just a couple of questions left on the well worn themes of EXCO and Brazil. Really just following up on Theepan's question, you mention that the near term focus is on appraising the Haynesville but EXCO seems to be in quite active discussions on selling their assets in the Marcellus. Just wondered in principle whether you'd be interested in looking at those assets.

And secondly in Brazil, the form of new regulations gradually seems to be taking shape which seems to be a move towards PSCs, versus the existing concessions. You are clearly going ahead with the fast track developments but could you talk about

possible unitisation issues with open acreage on lara and possibly Guara as well. Thank you.

Frank Chapman:

Yes I think on the emerging picture it is sort of clearing a little bit, it's not absolutely fixed at the moment. But the government is focused on continuing to attract international investors and they have been very strong on contract sanctity. And we've received a series of commitments from the governments in the sense of protecting current contractual arrangements. And we believe that any new arrangements that are going to come through are not going to affect existing concessions. That's what we've been - assurances have been given at the very highest level that this will be the case.

So we'll see in due course, we'll know when all of this is published, but we have a basis to believe that it won't affect existing contracts and that a move to PSCs will be in terms of the framework for new concessions.

Your other point was - oh Marcellus - I'm sorry I thought there was another point on Brazil.

Neill Morton,
MF Global:

Well it was with regards to unitisation with open acreage. I believe lara sort of goes beyond the boundaries of block 11 for example.

Frank Chapman:

Yes it's never going to be the case that all of the fields happen to fit neatly inside. I think we're in pretty good shape on Tupi and I think we're in pretty good shape on Guara. And it's clear that lara may have an extension. But in line with normal oil field practise, if somebody believes that

a discovery goes into their acreage it's incumbent upon them to drill a well and prove it.

I think the government at the moment has moved away, and the authorities have moved away, from this unrealistic notion that the pre-salt is one huge reservoir and that anyone who has got a piece of territory in that basin is going to be a party to one massive unitisation process. I think this is now realised not to be a viable position to take because we're finding that these reservoirs and the fluids that we find in them are not the same. And you know each and every structure needs to be explored.

And therefore I think the unitisation issue becomes one much more of individual fields, and for that there is a tried and tested sort of industry approach, rather than a sort of surreal prospect of 50 people in a room trying to carve up 280 kilometres by 70 kilometres or whatever it is. I think that prospect has really receded and people have been coming back to talk more sensibly about normal unitisation processes.

The government of course is extremely keen to see progress being made. And the reason that we're making good progress is government partner and operator alignment. And we're getting on with it. Basically we're making very good progress, and at the moment there aren't visible for us any obvious barriers or people saying here's a reason not to go ahead. So I think there's a sort of fairly pragmatic approach being taken at present.

Marcellus, look you know we tell the market about things when we do them. At the moment we've

done a deal in the Haynesville. We think it's very good. We've got our heads down trying to work that basically.

Neill Morton,
MF Global:

Fair enough, watch this space. Thank you.

Jason Kenney, ING:

Hi there. Just wanted to go back to Comgas if possible and the outlook for - that gas cost recovery in the next couple of quarters there. And you mentioned the earnings were in line with market expectations. I just wonder if you could maybe clarify a bit for the outlook.

And then secondly US power, obviously quite good in the second quarter. How long could that last?

Ashley Almanza:

Yeah on Comgas just to clarify that, full year consensus is around 270, 280 up to about 300. I'm just looking at Chris.

Chris Lloyd:

300 yes.

Ashley Almanza:

Yes. And what was your second part? LNG ...

Jason Kenney, ING:

It was on gas cost recovery.

Ashley Almanza:

Oh gas cost recovery, I beg your pardon. The unrecovered gas cost balance is £83 million and that will be recovered over the balance of this year and next year. And I think rule of thumb; phase it evenly or in line with the seasonality that's established in that market.

Jason Kenney, ING:

And then there was the US power outlook as well.

Ashley Almanza: Yes I think that we had a good quarter so in the US, in our power business. I wouldn't describe it as exceptional but I would say it's good. And clearly as we go forward we would expect a growing contribution from that business. But I wouldn't look to replicate that in the third and fourth quarter.

Jason Kenney, ING: Many thanks.

Lucas Herrmann,
Deutsche Bank: Yeah afternoon gents. I'm sorry to drag it out even longer. Three questions. The first is around pricing LNG spot markets and where it moves to. I mean I guess if we're in a market which is going to be you know relatively long supply over the next two to three years or potentially so, you know we've become very used to oil price linked formulas or oil price parity as a means of pricing spot gas going into Asia and other markets. But the option basically is - you know the final place of delivery is the US, to what extent do we actually start to move back to the higher of NBP or Henry Hub when thinking about spot contracts anyway, you know moving out over the next two to three years?

That's one question and generally I'm just intrigued as to how much more competition you now see in LNG markets when it comes to negotiating a short term trade?

Sorry still on LNG, Equatorial Guinea, there have been some comments over the course of the last you know few weeks or the last quarter certainly on the Equatorial Guineans dissatisfaction with the amount of money that you seem to have made out

of your contract with Marathon. I just wonder again whether it's something one should have any concerns about at all or whether the contract is written in well whatever it's written in and you know that's it.

And finally Ashley tedious question on costs, just what you're seeing in terms of you know what your experience around rig rates is at present. What your experience in general in terms of CAPEX and direction and deflation is, you know ballpark indications as much as anything on your experiences in markets given you're at a point where you actually are looking quite heavily at build across a number of areas.

Frank Chapman:

Yes Lucas I think that your first three questions all represent various dimensions of people trying to understand what's happening in the LNG business. And really this has been an area where we have tried very hard to help people build models. And we've come to the realisation actually that building accurate models in the hands of lots of people who are interested in calculating where the business is going, actually quite a task.

So a while ago we decided not to do any of this. We decided to give the market our best estimate of what we thought operating profit would be for a decent period ahead. So last February we gave you 2009 and 2010, and everyone seemed to be quite positive about the robustness of the earnings stream coming out of LNG. I think when we get round to February next year we will have another look at that with you and we will try to give a picture at that point to the extent possible of how the situation is going to develop.

And that in our way is a rolling up of all of the knowledge that we've got of the situation with competition, the way spot markets are working, how aggressive it is out there. Today we are saying once again we're happy to confirm £1.4 to 1.5 billion, and £1.2 to 1.3 billion next year. So all of this stuff in the mix, including Equatorial Guinea whatever you think is going on there, all of that in the mix, we're happy to reconfirm our targets and we'll give you some updates on that.

That's really all - we could get into a very long dialogue about all of the various elements but at the end of the day it's what do we think the business is going to do and that's what we think it's going to do. And you know we'll keep you absolutely in the picture as to how that evolves and we'll come round February, hopefully give you further insight. Ashley, costs.

Ashley Almanza:

Lucas on costs, on the operating line of course you've seen our unit OPEX come down. Year on year for the full year we expect unit OPEX to be down about 50 cents, so coming down from 6.40 to 5.90. There is - really it's quite a complex picture. It depends on what services you're looking at, the location in which you're procuring those services and the same is true on capital.

So in deepwater rigs we don't see inflation but we also don't see much de-escalation. As you look at jack-ups or land based rigs you see more scope for securing rigs at lower rates, clearly we're not seeing inflation in that area. Raw materials, undoubtedly very substantial reduction in raw material costs. And as we set about putting in

place a procurement programme for the projects which we're developing, we're taking great care to ensure that those falling material costs flow through to us, that the ball isn't trapped somewhere else, that the benefit flows through to us.

So quite a mixed picture but I think the assumption that we made in February this year of a 10% de-escalation in capital costs over the period out to the end of 2012, I think that's a prudent assumption. We feel confident that we can deliver that and yes unit OPEX we're starting to see some of the benefits already.

Lucas Herrmann,
Deutsche Bank:

Okay. Ashley, Frank, thanks very much.

Ashley Almanza:

Okay. Thank you.

Post Q&A Close

Frank Chapman, Chief Executive

Okay thank you very much. I think that's the last of the questions now so thank you very much for your participation in this session today. I have to say in what is a fairly challenging environment I feel very confident about the progress that the company is making. We have a very substantial resource base, and as you can see from some of the progress we're making with the business development and commercialisation, I think that we are making you know very sound progress towards delivering the potential value in our portfolio.

So if I may, in terms of wrapping up I'd just like to recap the main highlights.

- Production up 7% year on year;
- Excellent progress with project delivery;
- Excellent progress too with the reserves development; and,

- Further exploration in Brazil;
- We have our agreement with CNOOC which underpins the QC LNG2 train first phase development;
- We have the US alliance with EXCO, fundamentally economic, attractive opportunity;
- And of course we have delivered a 20% increase in our interim dividend.

So thank you once again for taking part in the conference call today and I'd like to remind you that we'll be announcing our third quarter results on the 28th of October. Thank you once again and goodbye.