BHP Billiton
Petroleum Business Briefing
Monday, 26 November 2001
Held at: Inter-Continental Hotel, Sydney

PHILIP AIKEN [President and CEO, BHP Billiton Petroleum]: Good morning, ladies and gentlemen. I would like to say how nice it is to be back in Sydney today.

For this morning's presentation I am going to call on some assistance. Sitting here from my left are Mike Weill [President Integrated Business Development], Terry White [Vice President Bass Strait and former Exploration Leader, Gulf of Mexico] and Greg Robinson [Chief Financial Officer]. They will be doing various parts of the presentation this morning. If I could just give you an outline of the presentation. It is in six parts, the first part is really an overview which actually Greg Robinson will start off with. Greg, as you know, is the CFO for Petroleum. He joined us from the investment banking group of Merrill Lynch.

I will then take you through our producing assets and then hand over to Terry White to talk about the Gulf of Mexico exploration. Terry is currently the Bass Strait asset team leader, but before he took on that job he was the exploration leader for the Gulf of Mexico. I am certain he will be able to give you detail about exploration programs in the Gulf of Mexico.

He will then hand over to Mike Weill. Mike is the head of Business Development. He is based here in Melbourne and Mike will take us through the rest of the exploration portfolio, talk a bit about the developments in the Gulf of Mexico and then talk about the gas business. I will come back on the last two sections to finish off on gas developments and talk about access to discovered resources, and then summarise at end.

GREG ROBINSON: Thank you Phil, and good morning ladies and gentlemen. It is a pleasure to be here this morning finally on the other side of the fence, a lot of friendly faces out there I have seen on other deals over the years.

I would just like to start by saying that I am going to give an overview of finances, prices, costs, reserves and production. BHP Billiton Petroleum is a fast moving medium-sized Petroleum company. It ranks 15th in the world by size, both on production and reserves. At the moment it represents around 39 per cent of the EBIT for BHP Billiton for 2001 year. Obviously that is price dependent.

On P90 [90% probability] reserves, Petroleum has 1.4 billion barrels of oil equivalent, with an annual production of nearly 360,000 barrels of oil a day. Reserves are split roughly 60 per cent liquids, 40 per cent gas. We have 1,700 employees and offices in four locations in the world: Melbourne, London, Houston, Perth.

Looking at the first quarter results, and you have all seen this and been through the results. We had a very strong first quarter, particularly in production. Our key three producing assets, North West Shelf, Bass Strait, Liverpool Bay, all performed very strongly and we had our first couple of months of production out of Typhoon in the Gulf of Mexico.

The oil price during the first quarter was $24.86, which was lower than our first quarter last year. I think the first quarter last year was roughly $29 a barrel of oil.

The outlook for the remainder of the year is obviously going to be dominated by price. To give you an idea on sensitivities, we see an EBIT movement of US$65 million for every dollar movement in the oil price. We can see that there is going to be a fair bit of volatility in the oil price over the coming months.

To give you a breakdown on the EBITDA for Petroleum, now again, just on a historic basis there will be no surprises here, you can see the three main drivers are the producing assets, North West Shelf, Bass Strait and Liverpool Bay. The interesting thing to know is "other" is now $462million EBITDA, and it is going to be growing strongly over the years. If you look at our project portfolio coming forward: Algeria, the Gulf of Mexico, the new Trinidad discovery, there is certainly going to be a lot of growth in that "other" category.

Prices. Again, volatility. The first thing to note here is that we are unhedged as a policy, we don't take hedging so we are exposed to the spot prices. If you looked at a way that we forecast price, we have a long-term forecast of US$19.50 and the way we actually look at our projects is we look at the forward curve for the next couple of years and then interpolate between the forward curve and our long-term forecast of US$19.50. That is the way we run our economics. Then we look at upside and downside cases, looking at all the normal sensitivities

Q. Declining in real terms?

GREG ROBINSON: Declining in real terms, yes. We decline about 1 per cent real over time.

Looking at proved reserves. Under 1P, 1.4 billion barrels of oil equivalent. Last year we produced around 130 million barrels, and we added to our reserves through Ohanet, the initial booking of reserves - and there will be more - at Atlantis and Mad Dog, Echo-Yodel and the purchase of Genesis. If you look at our P50 reserve base, it is substantially higher at 1.886 billion barrels of oil equivalent. That's roughly split equally between oil and gas. Behind that, again, is a gas company, almost of the equivalent size in static resources. So if you look at a 2P resource, we have another 1.64 billion barrels of oil equivalent, mainly gas, and of that 75 per cent is roughly in the North West Shelf. It is almost a mirror image company.

Reserve replacement ratio is running at about 112 per cent over the last three years. Given the projects we have coming forward, I think we will easily maintain that performance and better it.

Petroleum exploration spend. During 2001 the spend was US$196 million. A substantial portion of that is in the Gulf of Mexico; very expensive wells to drill but a very exciting acreage. During 2002 we expect to spend about US$250 million, and the focus is going to be roughly the same; the Gulf of Mexico, Australia and now around our Trinidad acreage with appraisal drilling there. We would expect about 20 per cent of that US$250million will be appraisal, the rest will go into pure exploration.

Our finding costs are about US$1.35 a barrel of oil equivalent. Our development cost US$2.89 a barrel of oil equivalent, total US$4.13 barrel of oil equivalent, and I will benchmark those later on. Our operating costs are US$3.16 barrel of oil equivalent. Again, that's a good performance. The average in the market is around US$3.69 per boe so we are a low cost producer. To give you an example, we have had a very good performance in Liverpool Bay over the years. In a two-year focus study on costs, we managed to reduce the operating costs from US$5.36 a barrel of oil equivalent down to US$4.97 boe which is again a very strong performance.

The G and A costs [general and administrative] are roughly US$15 million a month.

Very important slide here in looking at our production forecast. Our production forecast by 2007 is 180 million barrels of oil equivalent. That's an increase over today of a base of 130 million barrels of oil equivalent. That increase equates to about 5.5 per cent compound growth over those years. In looking at this forecast I have to read one caveat out: that it really is based on our current oil price planning scenarios, and is very much a forecast and subject to change as we go through our development proposals. Also note at the top of the slide we exclude exploration success.

Just to give you an idea of the sort of projects we are going to be bringing on over those years. In FY01 you have seen the start up of Typhoon; by FY03 we expect ROD [oil, Algeria] and the Zamzama full field development [gas, Pakistan] to be coming on; in FY04, Ohanet [liquids, Algeria] and Minerva [gas, Australia], and Mad Dog [oil, Gulf of Mexico] in FY04; then in FY05 we are looking at the North West Shelf [LNG, Australia] , Atlantis [oil, Gulf of Mexico] and Trinidad [gas and oil]. So towards the tail end of those years very significant projects fundamental to the strong growth in production.

In relation to the strong margins I was talking about a little earlier, I refer you to this chart. On the left-hand side of the box we are looking at our three core production assets and the average for BHP Billiton Petroleum. The price step we are using looking at these margins is US$25.58 a barrel of oil. If you look at it, the North West shelf obviously has the highest margin at US$12.84 barrel of oil-equivalent. Bass Strait has a margin of US$7.28 per boe, and Liverpool Bay US$7.88 per boe. As an average for BHP Petroleum, the margin is US$7.48 per boe against the FY01 price benchmark of US$25.58.

The oil price scenario on the right-hand side of the box is to illustrate that the margins are strong all the way down to a US$12 oil price. We will illustrate that when we look at the benchmark analysis on the next slide.

This is our peer group rankings over the period 96/97 through 2000/2001 [details on the peer group can be obtained by contacting BHP Billiton Investor Relations]. You can see that the finding and development costs performance has been very, very strong. It has moved up into the top quartile. Our reserves replacement versus our peer group has moved down, and I would say that Petroleum is quite conservative in the way that we book reserves. We would certainly expect our relative reserve replacement performance to improve as we book additional reserves for Mad Dog, Atlantis and Zamzama and start to book reserves associated with other assets such as Trinidad.

Production growth – a similar situation. We are going to see stronger production growth. As I mentioned earlier, 5.5 per cent per annum expected through to 2007.

The profit margin on a barrel of oil-equivalent basis , obviously this drives a lot of the investment community and shows what a very strong profit performer this business is. On both profit margin and return on capital we sit in the top quartile of our peer group.

With that summary I would like to hand it back to Phil. Thank you.

PHILIP AIKEN: Thanks, Greg. Let me now continue by talking a little bit about the managerial and other capabilities of Petroleum before moving into the actual assets themselves.

The Petroleum organisation consists of about 1,700 staff and contractors primarily based in four locations; Melbourne, Perth, Houston and London, but obviously we have a presence in other locations such Pakistan, Japan and Iran. The Petroleum organisation is led by the President and CEO, and I have now supporting me a leadership team known as the Petroleum Executive Committee. The Petroleum Executive Committee has reporting to it all of our operating assets, our exploration assets, and a series of global resource teams which, in effect, also have their own teams.

The organisation is based along the key stages of the exploration and production value chain. The Petroleum Executive Committee, as you see on this slide, reports through to the BHP Billiton Executive Committee and then that, of course, ultimately reports to the Board.

Since I have been doing these presentations, now for about four years, I think this is the first time I can actually say we have a full Petroleum Executive Committee. The Petroleum Executive Committee is responsible for the management of the Petroleum business as a whole. When I gave the last briefing we did not have it fully in place and therefore I am pleased today to say we have and it is working and working very well.

What does the Petroleum Executive Committee do? One, it is responsible for providing the high level strategic direction and clarity for the business; it is responsible for providing the leadership to the asset, resource and advisory teams; for overseeing business development opportunities; it is responsible for reviewing and recommending, where appropriate, key investment decisions; it is also responsible for establishing and monitoring the key performance measures of the business and providing an ongoing liaison with the BHP Billiton Executive Committee and the Board.

The members and their locations are on the slide. There is one missing, our Head of Human Resources, Mike Herrett. Mike is based in London.

Mike Weill is here today. Mike had a long career in Shell. He is an engineer by training and joined BHP some five years ago. Steve Bell, who is not with us today. Steve is a geologist who has a long career in the industry with Apache and more recently with Alberta Energy. Steve joined us about mid this year and is a very important person in our team, because Steve has a long history of finding oil. Steve is based in Houston and I am certain when you get to Houston at some stage we would be delighted if you would meet him.

Keith Hunter, who many of you know - actually Keith helped me with the presentation in London on Friday. Keith has been with BHP Petroleum a long time. An engineer by training, Keith is based in London and looks after all our operations and development, and then Greg Robinson the CFO based in Melbourne. Chip Goodyear sits almost in a non-executive role on to the Petroleum Executive Committee. He did that in the old BHP where the three non-line Executive Committee personnel were on one of the business groups. It is good having Chip involved because, as Chief Development Officer, a lot of the things we are doing in Petroleum he is aware of by sitting on the Petroleum Executive Committee.

That's the organisation. Where are we operating? Again, a slide most of you have seen before. This shows where our focus is, including our production, and we will be going through this in more detail. Petroleum, as you know, conducts international exploration with three areas of focus, and these are also shown on the map.

Just a few highlights of what has happened in recent time. Greg has already talked about the fact that we made US$1.4 million EBIT last year, generated considerable cashflow. Last year was a very good year. We booked at reserves in excess of 130 per cent of our production and we sanctioned a number of substantial projects. We have also made some good progress on key developments.

If you look at the highlights for the year, I would point out four in particular. One was the approval for the Ohanet wet gas project in Algeria. That is an investment for BHP Billiton of about US$430 million, and on top of the ROD oil field investment it gives us real critical mass in Algeria. Obviously the approval of the expansion of the fourth train of the North West Shelf is very important for the North West Shelf joint venture and very important for BHP Billiton. Our share in that investment is about US$260 million. The commencement of contracted gas sales in Zamzama in Pakistan, whilst a small step it is a very significant one for the business going forward and we will talk more about that in more detail soon. During the year there was the strengthening of our position and the development of our exploration and appraisal program in the Gulf of Mexico. Again, we will be taking to that in more detail a bit later on.

In looking at an upstream oil and gas business, there are three prime considerations for us. We think the first of those is safety and then production and then getting our costs right. Obviously our licence to operate is very much predicated upon an ability to operate safely.

In all our statistics, we have had considerable improvement. Our lost time injury frequency rate would now be at the very top of the industry worldwide at 1.09. Only recently we have received, for Liverpool Bay and the Griffin venture, ISO 14001 certification for our offshore and onshore operations. We are now working towards achieving those same certifications wherever possible across all of our operations. We carried out a number of audits, particularly in places like Algeria and Pakistan, where we are concerned with our operating performance. We do external audits and they are taken very seriously by the business.

Another thing we have started taking place is that across the country now we have leadership management meetings which is led by one of the Executive Committee members where we bring all of the asset teams in that region together and try and make sure we achieve the best learnings from our overall operating performance.

In finishing this section, let's just briefly review with you the Petroleum growth strategy. We have spoken to you about this slide before. Basically we have categorised our growth portfolio into three areas and one area of cash generation. The cash generation area comprises the assets whose primary strategic focus is to generate cash. They are also very much our licence to operate and very much how we are perceived in the industry as a whole. I think that Liverpool Bay will show that we have done very well here and are considered to be a very successful operator.

The three areas of business growth are high margin E&P; gas commercilisation, and discovered resources. High margin oil E&P comprises the projects which give us high returns, but are frequently characterised by high subsurface or technological challenges, yet in environments of generally lower political risk. For better than average industry players who can successfully manage the at times complex subsurface and technology risks, returns in this area can be very high. In addition, we can usually obtain exposure to oil price upside in regimes where we operate, such as the Gulf of Mexico.

In discovered resources we are looking at lower risk, already discovered resources in resource-rich countries that may offer significant growth opportunities for BHP Billiton in the longer term. The tradeoff here is a relatively fixed or moderate rates of return but there is little exposure to oil price upside and downside. An additional tradeoff in this area is country risk, and an example is an Iranian buyback contract.

The last area is our gas portfolio which provides exposure to a high growth industry sector and is robust to environmental and greenhouse pressures. Whilst some existing LNG contracts are linked price to crude oil, gas may also provide the opportunity of having better commodity diversification in the portfolio.

So they are our four main growth strategies, one built on cash and three ongoing businesses. Before I move into those, let me just finish off by saying that I believe the BHP Billiton merger has allowed us in the new group to enjoy an outstanding diversity of commodity exposures. The Petroleum business, which incorporates both oil and gas, as well as LNG, is a significant part of the new group and offers, I think, a great variety of both brownfield and greenfield growth opportunities, underpinned by a strong, high margin set of world class assets.

Many of you in recent days would have seen the portfolio risk management presentation [refer to BHP Billiton’s website for details of this presentation] which Rowen Bainbridge [Vice President, Market Risk Management] has been responsible for. You might remember that it showed that if Petroleum was removed from the BHP Billiton portfolio and the proceeds gained by a spin off or sale reinvested in metals and mining, the BHP Billiton cashflow at risk would increase significantly.

Therefore, Petroleum is a very important part of the BHP Billiton portfolio going forward.

It is a good business with a lot of brown and greenfield opportunities and, as part of the portfolio, it gives a diversity that none of resource industry competitors have. Whilst we have many good internal opportunities to grow the business, we continue to look at opportunities in the M&A area. There has been a lot of speculation in recent months about Woodside. Well, as you know, we have been in discussions with Woodside and also with Shell for a number of months, but at this stage there looks little likelihood of any transaction taking place. We always said to do something with Woodside we had to add value to the BHP Billiton shareholders. At this point in time it doesn't seem that is going to be possible. So for now, we can say we will not be proceeding any further but will be getting on with growing our business along the lines which we are going to talk to you about today.

Let me now move to and talk about production. When we talk about production we talk about five countries: Australia, United Kingdom, United States, Bolivia and Pakistan. Some of these assets are well known to you and some of them are quite new, so I will go through these to try to give you a rundown of the current status of our producing assets.

The Bass Strait [Australia] continues to produce in excess of 190,000 barrels gross of liquid per day [BHP Billiton's interest is 50%]. It is about 160,000 barrels of crude and condensate, about 32,000 barrels of LPG [liquefied petroleum gas]. It also produces in excess of half a billion cubic feet a day of gas, all of these are on 100 per cent basis.

Liquids production during the 2001 financial year has been maintained due to a successful infill drilling program. Bass Strait remains 40 per cent of Australia's petroleum liquids production, supplies about 90 per cent of Victoria's natural gas, and now supplies around 20 per cent of the gas requirements of New South Wales; in total, just under 25 per cent of Australia's total gas consumption.

BHP Billiton Petroleum is working hard with ESSO [Operator and 50% Joint Venture partner] to commercialise gas in Bass Strait. Again, referring to the figures you have been quoted before. About 89 per cent of the oil base has been produced, but less than 50 per cent of the gas reserves has been produced from Bass Strait. Later on in this presentation Mike Weill will talk about what we are doing as regards gas marketing and growth of the gas business from Bass Strait.

Let me say, we have been very pleased with how we have held up our production profile of Bass Strait liquids over forecast over the last 12 months. As I said before, we are now producing around 160,000 barrels a day of oil and condensate against the forecast 17 per cent annual decline I have referred to previously.

There are three areas which I think give us good scope for the future. Firstly, to accelerate oil production we are carrying out the West Tuna and Tuna infill program. We are currently undertaking a program which consists of six to eight wells at West Tuna and four wells at Tuna. This program commenced in mid-2001 and is expected to be completed around mid-2002. In total, it will capture about 9 million barrels of gross reserves, and that has an NPV for BHP Billiton of around about US$30 million.

The second project is the Bream Gas Cap development program. This program was approved in October of this year and is an investment of US$125 million, and consists of a 46km offshore pipeline and a 5km onshore pipeline from the Bream A platform. The new pipeline will allow the production of gas reserves currently being reinjected into the Bream reservoir. It will also accelerate the production of about 30 million barrels of hydrocarbon liquids over a ten year period.

The third area, and most exciting, but early days, is the new seismic survey we are undertaking. Here we really are looking for new plays, primarily oil, in an oil basin, through much improved 3D [three dimensional] seismic technology. The plan was approved and commenced in October this year to shoot 3,900 square kilometres of 3D seismic to identify hydrocarbon targets over a range of geological horizons. It is expected to result in a new round of drilling activities and could add to the proved reserves. Early days yet, but it really is a good opportunity to look at what else might be there by employing a modern seismic approach.

The North West Shelf and Laminaria [Australia]. Production in the North West Shelf and Laminaria in total exceeds about 700,000 barrels oil equivalent a day of which BHP shares about 130,000 barrels a day. The majority of revenue to date last year was due to high prices with record production levels and a low exchange rate. However, as oil reserves and revenue decline, LNG expansion in the fourth and fifth train will mean that LNG will become even more important in the future. In the coming year, LNG and oil revenue will be about equal at about 37 per cent overall.

The project continues to deliver about 126 to 130 LNG cargoes to Japan each year, and between two to four spot cargoes, primarily to the USA. The Japanese customers, including the largest electricity and gas companies, have currently 20 contracts which go through to 2009. The fourth train sales contracts with six other Japanese customers are currently being concluded and should all be concluded finally by 2002.

The North West Shelf joint venture also supplies about 70 per cent of Western Australia's domestic gas with major customers comprising large mining companies or electricity utilities. However, a number of gas opportunities have emerged and MOUs [memorandums of understanding] with Methanex for gas to methanol and GTL will increase, if they are successful concluded, domestic gas sales from the North West Shelf by about 50 per cent.

The North West Shelf venture itself is, again, well known to everybody here. It is an unincorporated venture of six partners. It started supplying gas in 1984 and of course the fourth train expansion was announced in 2001. The North West Shelf has enough gas to fulfill its existing contracts, assuming extensions, through to 2024 and has enough gas for the fourth and fifth trains. Oil production will probably reach a plateau in 2001 but will continue through to field-wide expiry in 2014. One of the priorities for the North West Shelf is to continue with gas exploration; we do believe that the oil prospectivity is fairly limited.

What's the main strategies for us in the North West Shelf? Going forward, obviously it is to commercialise the remaining gas resources in terms of domestic feeds to fourth and fifth train. Last Saturday I was in Beijing and signed on behalf of the North West Shelf partners a Heads of Agreement with the China National

Offshore Oil Company for them to participate in the fifth train. This really is an opportunity for them to play a role in the development of the Chinese LNG business by being an equal participant in that train of the North West Shelf. It is early days, but we do believe it is a very important first step in diversifying the North West Shelf's customer base from Japan, and the China tender which is currently under negotiation, is a very important tender for us.

Secondly, we will continue to accelerate liquids production and develop static resources. The Echo/Yodel and Angel fields we are developing are really about accelerating production. A third priority will be to engage those other gas resource owners, such as the Gorgon participants, in co-operative gas resource development, such that this can hopefully take place after the fifth train.

I have spent a lot of time in the last couple of years on North West Shelf business and a lot of time with customers in Asia, and there is no doubt that the North West Shelf has a wonderful reputation as a supplier, for the security of supply and the stability of supply, and it is something we hope to build on in the next few years.

In our North West Shelf asset team we also have the Laminaria/Corallina project. This is a project where BHP Billiton has a 32.6 per cent interest in Laminaria and a 25 per cent working interest in Corallina, the other partners in that being Woodside and Shell. The Laminaria/Corallina oil fields, which have been developed using the Northern Endeavour FPSO [floating production, storage and offtake vessel], which has a capacity of 1.4 billion barrels of storage. Oil production commenced from Laminaria in November 1999. Gross production levels peak at 180,000 barrels a day and averaged about 141,000 barrels during our last fiscal year. The share of BHP Billiton production during that year was 14.8 million barrels.

Field production rates commenced their predicted decline from plateau during the year and we brought forward the Laminaria phase 2 infill production. Production from this development is expected to commence in mid-2002 at an initial rate of 65,000 barrels per day, which will bring the total production at that time of Laminaria back to about 130,000 barrels per day. This project will enable us to develop underdeveloped reserves. It will see us bring an additional 21 million barrels of production on stream over two years. The capital cost of this project is about US$60 million, of which our share is about US$20 million.

Let me now move to one of my favourite assets, the Griffin venture [Australia]. Griffin's production during 2001 was 16 million barrels of which 7.2 million barrels BHP Billiton share. Gas production was 6.9 billion cubic feet, our share being about 3.1, and we also produced some 8,000 tonnes of LPG, about 3,600 net to BHP Billiton. The reason why it is one of my favourite assets is that it is one of our highest margin businesses, with a profit margin last year of more US$9 per barrel oil-equivalent

The Griffin field has now produced over 130 million barrels of oil, 58 million barrels to BHP Billiton, and has remaining resources of about 30 million barrels. At the moment we are commencing an infill program with Griffin 9, and when Griffin 9 is completed and comes on stream around about February next year, we also hope to have repaired the flow line which will bring the Scindian 1 and 3 wells back onstream. At that stage we will get the Griffin production back to about 50,000-55,000 barrels per day [gross] at a very high margin.

So Griffin, although it is coming to the end of its economic life in some ways, still has upside and the infill program will certainly assist in the next couple of years.

Liverpool Bay [United Kingdom]. I remember when I made my first presentation to this group about three years ago, every second question I got was about our poor operating performance at Liverpool Bay, and therefore I am delighted to be able to stand up these days and talk about the successes we have had there. Liverpool Bay has had an immense amount of focus on improving reliability and the stability of production, and we have certainly improved the Environmental Protection and Safety standards. Our focus now is about continuously improving and achieving cost reductions and a number of initiatives have been put in place to further reduce operating costs. An infill program will also be taking place to sustain enhanced current production, and we recently brought the Hamilton East Field on stream.

Current production from Liverpool Bay is running at about 62,000-63,000 barrels a day, and we are supplying 100 per cent nominations up to 300 million cubic foot a day of gas. So you can see its production is very significant.

To give you an idea of how it's performed. This slide shows BHP Billiton’s share of oil production over the last five quarters. You see it coming up after the September shut down last year and now averaging about 2.6 million barrels of oil BHP Billiton's share per quarter. Oil production has increased by 19 per cent from 1999 to 2000, and improved by 26 per cent in the first quarter 2001 from 2000. March this year was a very significant month for us when we actually moved four cargoes which was something a few years ago we wouldn't have thought possible. So certainly you can see a great improvement in our production performance.

Looking forward, we expect Liverpool Bay over the next few years to be a significant producer. There is only limited upside on the reserves side but there is a chance to accelerate gas, and there is always the possibility that we can also process third party gas from other parties who have gas reserves in the Irish Sea.

Upcoming major projects will be to continue to optimise the operating performance to maximise oil production. We will certainly be looking at associated gas capacity and enhancement, dual compression, and after we blow down the Lennox field gas cap we believe we can do additional work which will give us more production and reliability going forward. You can see where we are today and where we intend to go in production terms over the next few years, whilst also significantly reducing our cost base. It was often said that the old BHP had a number of troubled assets. A lot of them have either been shut down or sold. Liverpool Bay was a troubled asset, but we have really worked hard on it and I think we have gained great credibility in the industry with what achieved in turning Liverpool Bay into a very successful operation.

Also, over in the northern hemisphere, just across the other side of England, we have our interests in the North Sea. Bruce production last year - Bruce, of course you know, is operated by BP [BHP Billiton interest 16%]. It's production last year for BHP Billiton was about 2.6 million barrels of oil and about 32 billion cubic feet of gas. Since first production of this field back in 1993, about 46 per cent of the current reserves have been produced. During the year, the third phase of the Bruce development project began. This was first drilling from the existing platform to develop additional oil, gas and condensate reserves in the south and northern eastern parts of the field. These are very difficult horizontal wells in difficult conditions, but the first well was very successful and that program will continue over the next 12 months.

We also bought the nearby Keith field on production in 2002. This only cost about US$10 million in total but it brought on production of another 6,900 barrels a day, and 8 million cubic feet a day [gross, BHP Billiton share of equity is 31.83%]. We are now going to go ahead with the phase 2 production which will add another 10 million barrels of reserves and about 15,000 barrels a day in production [gross].

In the Gulf of Mexico, this is really the beginning of what I hope is going to be an ongoing story of high margin production growth. You can see our production going back to 1999 and 2000 and 2001 based on two small assets, West Cameron 76 [effective working interest of 44.1%] and Green Canyon 18 and 60 [20% interest]. Of course in recent months we've acquired Genesis [4.95% interest] and you can see there the effect of Typhoon [50% interest] , and now we are producing in excess of 30,000 barrels a day of oil equivalent our share out of the Gulf of Mexico.

Let me talk about the individual projects. Typhoon is, of course, the big story for us. The completion of the Typhoon facility was BHP Billiton's first deep water development. We have a 50 per cent ownership, the operator Chevron owns the other 50 per cent. The first oil was produced on July 29 2001 and Typhoon has a production capacity of 40,000 barrels of oil a day, which was reached in September. Boosting economics for this field, we are currently receiving royalty relief on our oil production and if gas prices remain at their current levels, next year we expect royalty relief on gas production as well.

Typhoon hasn't just been a financial success, it has also been an operational success. Execution of the project set a new benchmark for deep water developments in the Gulf of Mexico. The project was completed in 3.2 years from discovery and production was only 18 months after Board sanction. It was completed under the budget of US$256 million and it was completed ahead of time. Typhoon is designed to serve as a production hub in the Green Canyon area where BHP Billiton leases some 30 blocks within a 40km radius of the facility.

A lot of people ask what the involvement of BHP Billiton was in this development. BHP Billiton people were seconded into an integrated team with Chevron and, in fact, BHP Billiton personnel were responsible for all the subsurface work. We played quite a significant role in bringing this project onstream quickly. You might have also seen the recent announcement about the Boris discovery nearby. Boris will be tied back to Typhoon and we hope that it will be the first of a number of tie backs which will come from exploration success in that area.

The other bit of production in the Gulf of Mexico we acquired up was Genesis. We acquired a 4.95 per cent interest in Genesis from Total. The Genesis field, which is also operated by Chevron, commenced production in January 1999 and is producing about 52,000 barrels of oil and 90 million cubic feet a day of gas.

One of the reasons we got into the Genesis field was that it gives us a valuable proprietary insight into deep water development, especially utilizing the latest SPAR technology which we are going to use on the Mad Dog development. It also provides useful information on reservoir performance and qualities that is transferable to the Typhoon field.

One of the areas that has always concerned us in the US, is that while we have a very good track record in exploration, we don't have a lot of offshore operating experience. Both Typhoon and Genesis are giving us access to that experience which we know will be very valuable in the future.

Our last piece of production in the Gulf of Mexico are our old standards West Cameron and Green Canyon 18 and 60. BHP Billiton is the operator of West Cameron blocks 60, 61, 76 and 67. During the first quarter we completed a new well, the A5 well, which has been testing at 22 million cubic feet of gas a day. All in all, we are producing over 100 million cubic feet a day from West Cameron, and that continues to be quite a good asset for us.

From the other fields in Green Canyon 18 and Green Canyon 60, production last year was about 17 million cubic feet a day and 12,000 barrels. These are smaller assets coming towards the end of their economic life, but they still has some time in them.

Bolivia is an asset we haven’t talked a lot about. We have an interest [50%] in three producing blocks in the Mamore area of Central Brazil: Paloma, Surubi and Bloque Bajo. We are one of the leading producers of oil and gas in Bolivia, having a 50 per cent working interest in these assets with Repsol who is the operator and owner of the other 50 per cent. During this last year, the gross production was 10,700 barrels a day of oil and condensate. Importantly, we've also started selling natural gas from our Bolivian assets and gas production has increased substantially from an average of 14 million cubic feet a day, to about 26 million cubic feet currently.

This particular block, originally had 54 billion barrels of reserves of which we have produced 28. With infill drilling and other programs we think this will continue for a while, and we believe it can stay at those sort of rates for the next few years.

Finally, we went into production this year in our fifth country, in Pakistan. The Dadu block was awarded to BHP Billiton back in February 1995. After initial studies BHP Billiton farmed out 50 per cent to Monument and Premier and the first Zamzama 1 discovery well was drilled in February 1998. After a period of 2D and 3D seismic acquisition, a second well was drilled in 1999 and now in Zamzama we have low cost gas reserves of between 1 and 2 trillion cubic feet [gross].

In May 2000 we signed a preliminary development plan with the Pakistani authorities and submitted a notice of commercial authority and application for development of production. Together with our joint venture partners and with the cooperation of the Government of Pakistan, we have pursued a commercially focused fast track appraisal and development program. The extended well test enabled the joint venture to implement an innovative low cost development, whilst testing the ability to receive regular payments for gas produced. At the same time we were able to establish credibility with those existing and future potential customers and the Pakistani authorities. Where a lot of other companies were continuing to talk about gas developments, we actually got into production.

The Pakistan project management has gained very good experience from its extended well test and, although only designed to produce 70 million cubic feet a day, it has been producing in excess of 90 million cubic feet since production. Even during the last few weeks, following September 11, we have been able to continue to supply to customers and we are continuing to be paid in US dollars. Zamzama has been a nice development and we will talk about full field development in more detail when we talk about some of our growth strategies going forward.

That then completes the section on production and we get into the area of high margin exploration. In this area we will talk about the development of our Gulf of Mexico acreage and West Africa, but I thought today we would take the opportunity of having someone who is very knowledgeable in the exploration program present, so we have asked Terry White to dig back into his past think to talk about the Gulf of Mexico.

TERRY WHITE: Good morning, ladies and gentlemen. As Phil said, I am going to give you an overview and update of BHP Billiton's activity in the Gulf of Mexico and the exploration program. It's a pleasure for me to do this. I spent four and a half years working on the program so I am pretty passionate about the results and the potentials I can see there. I have to say if there is any lay explorers in the room, that is the place to be.

I want to talk about our exploration strategy; the results and successes we have had to date and our forward plans as we look to the future are very much underpinned by a consistent vision and strategy that has been in place in the program since the early 1990s when we first got into the deep water. As you are aware, exploration is a risk reward business and it is very important to have a clear and consistent direction, particularly when you are faced with high drilling costs and the long cycle times that we have to mature our prospects in the deep water.

Our approach is based on three key business drivers: focus, technical capability and commercial capability. Focus, the notion here is that what we have sought out to do is to identify high potential areas in the basin where we think there is good resource potential and we have the ability to develop the knowledge and the skills to work in those particular areas. Our assessments are based on a consistent technical methodology which is called Petroleum System Analysis which is used widely in the industry. Having done that, we have attempted to build material positions which have follow-up potential. It is important, we think, not to have a scatter gun or one-shot approach to your exploration, so we seek to find areas where we can learn from our success and failure.

Also, having done this, we have tried to identify the key wells to test these areas and have appropriate go forward and also exit strategies. In line with this approach we have chosen to be active in the area called the Central Gulf of Mexico which I will highlight in a slide that is coming up.

The second key plank to the strategy is technical capability. We have sought and been successful, I think, in building a team and an infrastructure that ensures that we have high competence in the key technologies that you need to explore in the basin and these are basically depth imaging which is working with seismic data, lithology and fluid prediction, the ability to predict subsurface pressure and also drilling technology. Competence in these particular areas really underpins our ability to put together an appropriate risk management strategy. It underpins our partnering strategies and also it is critical to identifying new opportunities.

The Gulf of Mexico is a leading edge basin and it does provide a lot of challenges and these technical capabilities underpin our activity.

The third area, which is our commercial capability, we think this is critical and we have sought to be creative and seek to put together some win/win deals in our relationships. It is important there's a strong liaison between the commercial and technical assessments to identify and capture new opportunities and also to develop these partnering strategies. We have developed much of our position in the Gulf of Mexico through early low cost entry, but we have also paid to get into opportunities where that seemed appropriate.

The Gulf of Mexico is a unique commercial environment in that the blocks we acquire are very small, they are three miles by three miles, and this generates quite an intensive competitive commercial environment. So our strategy has been underpinned by the ability to work these three key elements together.

An obvious question is why we have chosen to explore in the Gulf of Mexico and spend a significant portion of our global exploration budget in this area. This slide seeks to address that question in part. BHP Billiton and the industry in general considers there are significant undiscovered resources within the Gulf of Mexico. The estimates range from 10 to 40 billion barrels of oil equivalent. The consensus range would have that more in the mid range of 20 to 30 billion barrels of oil equivalent. Clearly there is a huge prize here and there is the potential to build large material businesses.

In the slide the blue graph illustrates the success to date in the Gulf of Mexico from the shallow water or the shelf exploration. You can see that there has been discoveries of approximately 40 billion barrels from over a thousand fields. You could note how the early discoveries tend to come up with a lot of the larger reserves. The red line shows industry results to date from deep water exploration. The steepness of the curve illustrates that we are in the early days of this exploration, and we consider that it has strong potential to track the blue line or the results that we have seen in the shallow water. So we consider that deep water has great potential and still a relatively immature area.

Another way to look at the maturity of the basin is by looking at the distribution of the wells drilled to date. This is a map of the Gulf of Mexico showing the distribution of deep water wells which is shown by the red dots. The green outlines areas where there is a subsurface salt canopy and I will demonstrate that a little bit later. The outer edge marks an area where the water depth is about 6,000 feet and the inner edge up through here is about 1,500 feet.

The exploration to date in the deep water has been mainly focused up towards the shallower portion of the area and what industry has been doing is trying to explore in the white gaps, and they are areas between the salt canopy. Now what the industry is tending to do is to move out towards the deeper portion of the basin and we are starting to explore in areas which are totally covered by the salt canopy. We believe, and a lot of other players believe, that there is significant remaining potential within the basin within these areas.

This map's also a good map to illustrate the concept of focus that I mentioned before. BHP has chosen to explore basically just in what we call the Central Gulf of Mexico, which is this area through here. There are large areas in the Western Gulf where we are not active, so we are a very focused player in terms of what we have decided are the key areas.

One last issue on the potential of the Gulf of Mexico is that I shouldn't fail to mention that the deep water reservoirs are characterised by very high production rates, and the individual wells can produce in the order of 20 or 30,000 barrels a day which obviously generates outstanding economics.

This is a slide which I would like to use to try to give an overview of some of the play types that we have been targeting with our exploration. It is a schematic geological cross-section which effectively runs north to south through the basin. On the left-hand side from water depths 0 to 600 feet, and then you move across to the right it heads out into the deep water where the water depths are up to 10,000 feet. The areas marked in yellow are intended to demonstrate the potential reservoirs and trap types that we explore. I think you can see that the geology is complex but there are a lot of potential reservoir traps in different depths and different settings in the basin and this is one of its attractions.

The complex geology and the geological history is associated and generated by the large salt bodies that occur within the basin shown here, different areas. One thing that should be noted is if you look at the water depth across the top, where the salt bodies end this area is called the escarpment and there is a significant increase in water depth from about 4,000 feet down to 6,000 feet, and the Mad Dog and Atlantis discoveries that we will discuss later in the presentation sit in this particular area.

Historically, industry has explored in the shallow water depth on the shelf which is a 0 to 600 foot area, a relatively shallow reservoir, this area over here, and the target reservoirs around the soft bodies and associated faults as you can see there, and typically down to depths of about 20,000 feet. What has happened with the deep water exploration is as production technology has allowed us to move out into deeper water, industry has targeted some of the similar play types but out in the deeper water depths.

At the same time we have developed the techniques to be able to image beneath and around the sides of some of these salt bodies, and it is that seismic imagining technology which is critical to unlocking new potential plays within the basin. As I mentioned, part of the BHP Billiton portfolio is out in the deep water in this sort of setting, out below the edge of the salt canopy. Features such as this would be analogous to Atlantis or Mad Dog. Typhoon sits in the setting like this and that trap is really quite shallow in this section not associated with salt, but we have targeted and are putting together a portfolio that targets quite a variety of different play types.

Clearly one of the key success factors that I mentioned earlier is our ability to drill in these water depths and we have some world class performance, we think, from the CR Luigs, which is the deep water drill ship that we have been operating within the basin. The latest activity having moved out into the deep water is industry is now starting to explore much deeper within the basin in the depths of the range of 20 to

30,000 feet.

This slide illustrates the BHP Billiton position and that of our major competitors in terms of the number of leases that we hold within the deep water. We are currently one of the largest lease holders in the deep water Gulf of Mexico, and we presently have 218 leases in the deep and ultradeep water. As I mentioned, these are concentrated in the Central Gulf of Mexico play fairways and are targeted to key areas that we consider have the highest potential. In relative terms we have slipped back in recent times in terms of the number of blocks that we have. We think rather than the number of blocks, it is more critical obviously the potential of the acreage and we have also been very selective and sought to acquire acreages at low entry costs.

This chart gives a quick overview of the results of the exploration program to date starting in 1994. We have participated in 34 wells, 22 of these are exploration wells and 12 appraisal wells resulting from the discoveries. The highlights to date include an 18 per cent commercial success rate in exploration drilling and we are hopeful this will increase to just over 30 per cent to the inclusion of discoveries that are currently in evaluation as tie back opportunities. We have completed one project, Typhoon, and we expect to sanction Mad Dog and Atlantis in the current financial year.

A key component of our activity and strategy has been leveraging opportunities and we have promoted more than a quarter of the wells that we have drilled, including six of the last 12 wells we have participated in. The last remark I would like to make on this slide is that for the last three years we have been participated in the deep water Gulf of Mexico benchmarking study which includes all the major competitors in the basin, and amongst our peers we are in the top quartile performance in terms of finding and completion costs and have a cost of US$1.07 per discovered barrel. This is calculated on a three year moving average. These are discovery barrels not booked reserves.

During the 2001 financial year we spent approximately US$109 million on the Gulf of Mexico exploration program which includes drilling, G&G [general and geophysical] costs and land costs. This year we budgeted approximately US$123 million but this may increase with success. A substantial portion of the money has been spent on appraisal activities in the Atwater foldbelt, but with the completion of the appraisal on the programs of Mad Dog and Atlantis this will shift. This slide outlines some of the exploration prospects that we expect to participate in over the next two to three years, and we would expect to participate in the order of five plus wells per year.

As in the past we plan to seek farm outs and promote some carries as a means of extending our exploration budget and reducing our finding costs. We are always trying to look for more commercially innovative ideas to work. For example, we were almost totally carrying the Mad Dog discovery well but we paid significantly reduced costs in the well earlier this year.

In our prospect inventory we have a variety of features which target a variety of different play types and they cover a range of sizes, risk profiles. Some are in our core areas adjacent to the existing discoveries and in some we will attempt to test potential of new play types. We believe that the Gulf of Mexico is a premier basin to grow our business. It has world class potential, attractive returns and it is close to markets. As I mentioned, we consider it has significant undiscovered resources.

We've built a strong position which we intend to build from and I can rest assure you that the Houston team is focused on delivering value as quickly and as rapidly as possible. Thank you.

MIKE WEILL: Morning. I, like Terry, also came from the Houston office. Before my current job I was head of the development group there, and it is a real great pleasure to stand up here knowing that Typhoon is onstream, on budget, on time, and that Mad Dog and Atlantis are coming down the home stretch.

This is a 3D slide from a 3D visualisation. This is normally something that is projected on a wall and under usual circumstances all of you would have 3D glasses and you could actually see this thing in three dimensions. This is a picture of the subsurface, with the top of the structures of what Mad Dog and Atlantis are like. This is the Atlantis and the Mad Dog structure here. The wells that we've drilled are shown in the yellow lines, and the highs on this map are the reds and the deeps are the purples.

Just to give you a feel of the magnitude of this which you really need to see in 3D, from the end of Neptune here to Mad Dog over here is roughly 50 miles across and the height from the top of the Atlantis mountain to the bottom of the valley is about 7,000 feet, so a thick mountain range here. Very big structures.

As I said, the wells that we drilled are up there. Neptune, Atlantis and Mad Dog basically sit along one ridge. Frampton, which we drilled earlier this year, sits on the ridge in front and the Shenzi, Komodo and Puma prospects sit right behind it. As you are aware, we announced earlier that the appraisal of these structures for Mad Dog and Atlantis in particular are finished. Let's talk about the developments and how we are going to develop these things.

This is a slide that shows the various development concepts that have been used in the Gulf of Mexico. This slide relates to the Gulf of Mexico or the similar data I will talk to is from Brazil because that is where some of the records are being set. In the old days we did thick structures. I remember a 1978 platform was set in 1,000 feet of water in the Gulf of Mexico. That was a record at the time. It took 15 years to get to Auger in 1993 which is in 3,000 feet, and was a TLP [tension leg platform] which looks like this. To get from Auger in 3,000 feet of water to Mensa in 5,000 feet of water took only five years, and basically the industry is at 6,000 feet now and pushing out from there.

The current drilling record in the Gulf of Mexico is 9,727 feet which is only about 100 feet deeper than we drilled at Chinook. The drilling tends to lead the production so we are already drilling in 9,000 feet water depth. Petrobras has the current water depth record at about 6,100 feet in Brazil for production facilities.

You see various types of facilities here. The one that is obviously missing and the one that BHP Billiton is quite familiar with is the FPSO. The FPSOs haven't quite come to the forefront in the Gulf of Mexico for various regulatory reasons. There are compliant towers, this is structured more to the seafloor. Many TLPs, like Typhoon, are floating production systems which basically look like drill ships connected to the seafloor. SPARs, long cylinders and TLPs fixed with steel tendons to the seafloor, and subsea, things like Popeye and Mars and Mensa are tied back to other facilities.

The primary difference between these two types of projects, and it is quite relevant to how we go forward, is the compliant towers, the mini TLPs and the TLPs are fixed to the seafloor, therefore the platform doesn't move up and down, it just sits there. The SPARs, the semi-shaped floating production systems are basically anchored and they do move up and down. The issue in the industry, as we go forward and develop these things, is not what the thing at the surface looks like, it is not really what is on the seabed, be it wet trees, (trees under the sea), or dry trees (trees at the surface), the issue is how do you connect those two things up, and it is in the moorings and the risers that have been the challenge and the industry is quickly overcoming those things.

This is what Mad Dog may look like. There are various facts and figures down the right side of the chart. Last month we announced the completion of our appraisal and drilling programs at Mad Dog. Mad Dog appraisal included four wells and four side tracks. We expect to sanction the Mad Dog project in the next couple of weeks, and we expect it to be in the volume range of 200 to 450 million barrels of oil in a gross sense. Genesis has, and Mad Dog will be developed using SPAR technology. It will feature a massive production facility equivalent in size to a 50 to 60 storey skyscraper from the very bottom to the very top of it, and it will have a capacity of roughly 80,000 barrels a day and 40 million cubic feet of gas per day.

It will contain a drilling rig on the surface and it will have dry trees, meaning the well heads will be at the surface as opposed to seafloor. At Mad Dog the primary reason for this is that the field has a relatively small footprint on the seafloor and you can do this and you can reach everything basically from the one platform. That is quite different from Atlantis. The other feature of Mad Dog, and Mad Dog will be the first, is that Mad Dog will sit up on top of the escarpment in about 4,500 feet of water, whereas Atlantis will sit down at the bottom of the escarpment.

What does Atlantis look like? This is a picture basically looking at the escarpment. At the top of the escarpment you are in about 4,500 feet of water, and at the bottom of the escarpment you are in about 6,100 feet of water and that is a fairly steep drop over a ten mile distance. So it is fairly steep as you come off this thing.

The footprint of Atlantis is quite a bit larger than the footprint of Mad Dog which drives us to the semi-shaped facility, probably without a drilling rig, and we will drill wells through subsea tankers. Atlantis is 400 to 800 million barrels, a significant development in any sense of the word. This makes Atlantis one of the largest fields discovered today in the Gulf of Mexico, after Crazy Horse, Mars and Ursa. It is amongst the top 50 ever discovered in the United States. Put that in a population of roughly 31,000 fields in the US. A significant asset.

BHP Billiton owns 44 per cent of this asset. As I said, it is in 6,000 feet and the development will likely have a capacity in the order of 150,000 barrels a day. We are currently working with our partners to narrow the options down and determine the details of the production facilities that we will use for this project. This will be disclosed more fully and we expect sanction sometime in the first half of next year. Development costs on both of these projects are going to be in the order US$4 a barrel or less. So quite good.

Where does this put us in terms of production in the Gulf of Mexico? This is a chart showing barrels of oil equivalent per day for the various companies down the left side. There is about a million barrels a day being produced in the Gulf of Mexico today. Shell produces almost half of that at 450,000 barrels a day and BP comes in at about 175,000 barrels a day and it tails off quite fast. BHP Billiton, until very recently, was way down at the bottom. With Typhoon we immediately go up to the middle of the list, and you can see we are now producing about 25,000 barrels a day.

This is a forecast that was generated looking forward five years from today. The orange band represents the high and the low forecast for oil we are producing from our total Gulf of Mexico production. You can see we will go from about 15,000 barrels a day in FY01 through 25,000 barrels a day in FY02, and the big projects, Mad Dog comes on in FY04, Atlantis comes on in FY05, and the variable will be 80 to 160,000 barrels net to BHP Billiton by the end of the period. Production at that level can easily put us in the middle of the top three or four on that prior graph. Significant given the short period of time.

Q. What proportion will be gas?

MIKE WEILL: That's in oil, basically an oil forecast and the GORs [gas-oil-ratios] are about 500.

Let's talk about profitability for a minute. Profitability is also an issue in the deep water; big costs, expensive drills, et cetera. Until we actually get one of those projects up and we can talk about specific numbers I will talk about indicative costs, but I think you will find it relevant to the types of developments I have given you already. If you look at US$18.50 WTI, if it costs a dollar, which is roughly what we are spending for exploration, for finding costs, US$3.65 to develop the field, US$2.47 to operate it, US$4.22 in government taken, that's royalty and tax, 35 per cent tax rate and royalty of 12 and a half per cent, US$2.92 cost to basically get the oil and the gas off the platform to the beach or to the WTI equivalent, which leaves us a margin of about US$4.25 in an US$18.50 world.

In a US$14.50 world we still make US$2 a barrel margin and in a US$25 a barrel world we make a US$8 dollar margin. These are quite good margins and they stand up against the other pieces of business.

One thing that isn't reflected in here is royalty relief. As we talked about earlier, for Typhoon we got royalty relief. That's a 12.5% burden. All leases post-1996 were automatically granted royalty relief on the first 82.5 million barrels. Leases issued before 1996 were not automatically granted. Typhoon fell in that category and we had to actually file for it.

Moving away from the Gulf of Mexico, this is a slide that shows Angola and Gabon, our two deep water focus areas in West Africa. In Angola we have been employing conservatism. You have no doubt heard of all the discoveries in the Lower Congo Basin there. We took Block 21 in January 1999, where we are 30 per cent owner and the operator, and Block 22, next to it. BHP Billiton has a 15 per cent non-operated interest in that block. The first exploration well was drilled in September of this year on that block and further drilling is being evaluated as we speak.

In Gabon we farmed into the Otiti and Tolo blocks from Arco. The first well on the Tolo block was drilled in October of this year and, again, we are basically in evaluation mode and looking to see where we go next.

Turning to gas, I'll talk about four areas in gas and growth in gas: Eastern Gas here in Australia; New South Wales, Victoria, South Australia and Tasmania. I want to turn it back over to Phil to talk about the North West Shelf in Australia, Zamzama in Pakistan and the oil prospect that turned into a gas field which has now turned back into an oil field, Aripo, Angostura and Kairi, in Trinidad.

Bass Strait. We have been focused for years on oil in the Bass Strait. The cumulative production on the oil side is about 89 per cent, about 11 per cent of the reserves remaining there. On the gas side the picture is quite different. We have only produced 45 per cent of 4.7 Tcf [trillion cubic feet] in the gross sense of the gas from the Bass Strait. Of the future volumes to be produced, about a third of it is contracted and about two-thirds of the remaining to be produced is not contracted. As we look forward with the oil declining in the Bass Strait, the emphasis here will be to commercialise gas.

What are we doing there? If you look at Eastern Australia you basically have four basins that potentially can supply Eastern Australia. You have the Bass Strait which has been there the longest - actually the Cooper followed by the Bass Strait. Those are the two proximal ones. You hear a lot these days about PNG and the Timor Sea. While we hear a lot about PNG and the Timor Sea, we have been quietly going about contracting gas and basically pushing out of Victoria into New South Wales, into Tasmania, and now hopefully with Minerva into South Australia. We fundamentally believe that Bass Strait gas is quite competitive with any of these other sources, and will continue to be competitive.

In terms of specific activities. In September of 2000 Duke completed the Eastern Gas pipeline connecting the Bass Strait and New South Wales. We now have a 20 per cent share of that market and we look to grow that as we go forward. Recently, BHP and ESSO have signed a contract underpinning the pipeline to Tasmania. Again, Duke will build that pipeline and BHP Billiton will underpin that pipeline.

In the downstream we already have contestabilities in the commercial and industrial sectors. Retail contestability will come shortly. We are reviewing how we will react to that as we go forward and look downstream as to how we might make margins in the future. We've BHP Billiton and ESSO commencing supply to BHP Steel at Port Kembla and the Smithfield power project shortly after completing the Eastern Gas pipeline.

In the upstream we are looking at what do we do with Minerva and what we do with Bass Strait. In the Bass Strait it is about contract expansion, in Minerva it is about the memorandum of understanding that we signed earlier this year with ANP in South Australia. The intent is to bring Minerva gas onshore, process it, pipe it to South Australia.

Beyond these developments, as Phil mentioned earlier, we are shaping the northern margin in 3D in the Bass Strait. We haven't looked for gas frankly for 30 years in

Bass Strait, and no doubt there is more gas to find.

Looking forward, what does this do for us? As I mentioned, the oil, as you are well aware, has fallen away quickly. This is a chart that shows the production revenues as we look forward in time for crude oil, condensate, LPG and gas. As you can see, the gas wedge does not quite replace the oil wedge, but it goes a long way to actually underpinning our strength as we go forward. The assumptions in this chart, it assumes that the growth in the gas sales will be about 116 BCF, and we capture about 35 PJs [Petajoules] per annum net in New South Wales to our account, and 20 PJs per annum in Tasmania for the 2003 fiscal year. Our gas prices are assumed to be basically what we are getting today in Victoria on the revenue side.

Is this aggressive, yes. Can we achieve it? Absolutely. With that I will turn it over to Phil.

PHILIP AIKEN:

What's going on the North West Shelf? I just wanted to reconfirm three things I've already said before. Firstly, uncommitted reserves of gas are available for the extension of the LNG contracts for a further 15 years. Therefore the North West Shelf going forward has significant potential growth in LNG. We are talking to further contract volumes in Japan and we are also looking at other opportunities in China, Korea and Taiwan. As I said before, the heads of agreement was an important first step in trying to be successful with the supply of LNG to Guangzhou, our project in China. The short list will be known later this year and we do believe that Australia is in a good position to be successful here.

Domestic gas opportunities have certainly grown and there are two important ones which are currently being pursued. The North West Shelf participants signed a memorandum of understanding with Methanex Australia Pty Ltd to supply gas to the planned methanol project. This agreement involves the supply of 200 terra joules a day of gas for a 25-year period from 2005. Under the agreement there is also provision for the North West Shelf to supply another 200 terra joules a day if Methanex decides to double the size of that plant. The Petroleum project continues to go through its process and does also appear to have good opportunities of going forward. So besides LNG, there are good domestic gas opportunities for the North West Shelf.

Coming back to Pakistan, as I said before in April 2000 we commenced a 21 month extended well test. Commercial production actually commenced on 26 March 2001, and over the last three months has been supplying in excess of 90 million cubic feet a day. To the end of October, gas from the extended well test sales have been 18 billion cubic feet and we have also produced about 117,000 barrels of condensate. We now have letters of intent from customers and an allocation letter from the President of Pakistan for gas sales totalling 320 million cubic feet a day. The gas sales and purchase agreements which will underpin phase 1 of the full field development are currently being negotiated. The capital and drilling cost of phase 1 of this development will cost about US$40 million, BHP Billiton's share.

So the Zamzama project full field development is a very, very good project, robust and the first sales from phase 1 should occur by about the first half of 2003.

Obviously, things have been slowed a little in Pakistan since the events of September 11, but we are still very confident of signing a full field development within the next few months.

Let me now turn to Trinidad which we think could very quickly become a major core area of BHP Billiton. Located off the coast of Venezuela and South America, Trinidad has a long history and a long pedigree in hydrocarbons. It is the world's leading exporter of methanol and has a sophisticated petroleum infrastructure. Following a continuous and significant drop in Trinidad's daily oil production, I think it peaked at about 240,000 barrels a day back in 1978, the government of Trinidad and Tobago wanted to generate more company interest in its offshore acreage by revising its contractual regime to more internationally acceptable terms. In 1995 it invited foreign companies to bid on acreage offshore the eastern coast of Trinidad under revised fiscal terms that included the implementation of a new production sharing contract model.

BHP Billiton conducted studies in the late 1980s. In 1996, after filing specific applications, BHP Billiton signed a 25-year production sharing contract for two continuous exploration tracks. These are now in the fifth year of their sixth year exploration terms.

The two blocks which are approximately 450,000 acres in size are located immediately off the east coast of Trinidad in water depths ranging from about 50 to 60 metres; that is not very deep. The initial seismic shoot was conducted to acquire proprietary data on the blocks and the drilling program was initiated in 1999. The first discovery in Angostura was made that year. That was basically a gas discovery.

A year later the Aripo discovery was made. This was a gas discovery where we also found an oil rim. Then the Kairi discovery was made in 2001 where we found an oil rim. The latest well, Canteen, is currently nearing completion and, as we now saw this month, is another discovery in which results confirms the oil potential in this area. So to date we have drilled some five exploration wells and appraisal wells discovering both oils and gas.

The Canteen-1 well is TD [total depth] and has indicated hydrocarbons. A testing program has commenced. I think that in itself signals that significant hydrocarbons have been found, and a full release will be made when the testing program is complete, expected in a few weeks time. We are very excited about the latest results and we think it marks a possibility to become a core area for BHP Billiton. I think you are going to hear a lot more about Trinidad in the future.

We have been asked many times, and I know I will be asked here later on if I don't comment, what sort of reserves we looking at here. It is very early days as yet but we do believe the oil discovery is in the range of hundreds of millions of barrels and when pushed I would say at this stage we hope something in the order of 300 to 400 million barrels [gross]. I would put the caveat on that that this is very early days and this is still very at an evaluation stage.

It is also a project we can fast track being relatively close to the shore and in relatively shallow waters we believe we could have production on line within a couple of years, and that would be very important to us because it would add value very early. We also have an addition 1 TCF of gas which could lead to commercial exploitation at a later time.

As part of our ongoing program and our thoughts about Trinidad, we have also gone out for more exploration and we were recently awarded exploration block 3(a) which is adjacent to the block 2(c) where we have made our oil and gas discoveries. Negotiation of a production sharing contract with Trinidad's industry ministry is underway and this again is expected to be executed in the next few weeks. Block 3(a) provides us with high prospective acreage and our knowledge in the adjacent areas can only enhance our efforts in this newly acquired block.

Trinidad's political stability and attractive petroleum geology together with the improved contract terms, make this one of the most attractive exploration areas in the Latin American and Caribbean region, and BHP Billiton certainly has a strong position which we hope to build on in the next few years.

The final part of our strategy is what we call access to discovered resources. We have often talked about it in terms of desert and other things, but this is really the third part of our growth strategy where we are looking at getting access to reserves which have already been discovered. In this area we have mostly to date been involved in Algeria and I will update you on how those two projects are going in the moment, but we do see a number of opportunities in the Middle East, and have a number of opportunities which we are currently evaluating. Of major interest to us is Iran. Iran has huge reserves; 9 per cent of the world's proven oil reserves and something like 16 per cent of the world's gas reserves. There are opportunities in Iran to enter the business by getting involved in buyback projects.

Australia and BHP Billiton have very good relationships with Iran, and Iran also wants to develop its mineral sector and sees BHP Billiton as a company that can be involved in both oil and mineral developments.

We have been in discussions with Iran for some time about buyback opportunities and we are currently at an advanced stage of discussion over the rejuvenation of the Foorozan field to enhance production levels. This field has been in production since 1975 and the production could be rejuvenated through a technology package. This project could be BHP Billiton Petroleum's first project in Iran and with our excellent relationships could be the significant platform on which to build further growth. Iran is an obvious location for supply with its growing energy demand, and this obviously is the sort of area we look quite strongly at being involved in.

Iran is also a country where we can identify the most potential for medium-term access to huge gas resource. The Iranian authorities are seeking an industry perspective in the planning and development of gas resources, and BHP Billiton is one of nine companies currently involved in the consortium to carry out a study on how to best utilise the gas from the huge South Pars gas field over the next 25 years. This study will be completed in about nine months' time.

We are also looking at other countries in the region, Syria is one. One of the problems we find in certain parts of the Middle East is that projects you're offered the fiscal terms are so harsh they are just not worth being a part of. Hence we are trying to balance the country risk, the fiscal risk and also making sure that the projects we are into are ones that add value to our portfolio.

Let me talk more about Algeria. BHP entered back in 1989. We have had successful exploration, very good relationship with SONATRACH and, as you know, we captured the 401, 402 project and the Ohanet project. At the moment BHP Billiton is looking at investments totalling US$1.5 billion [gross] in Algeria and I will speak briefly about those two going forward.

The first of those is the ROD integrated development. The ROD project comprises the integrated development with the BRN facility located in block 403. It is actually the development of six accumulations in 401, 402 with BHP Billiton holding 45 per cent interest. An agreement has been agreed and the oil reserves involved in this development are 299 million barrels. BHP Billiton's entitlement under the production sharing contract is approximately 65 million barrels. The capital cost of this project is just on US$500 million with BHP Billiton's share being US$200million. To give you an idea of the progress we have made, all of the drilling contracts have been awarded and civil engineering for drilling campaign is now well underway of the 19 wells planned..

We also expect to award the EPC contract in the near future. This is a bit later than we would have hoped, for a number of reasons, but it is also quite significant that during this time we have been able to revise our capital cost and any value we have lost in the timing we believe we have made up by reducing the overall capital cost. First oil is still expected during fiscal year 2003, but this is subject to final government gazetting and contracting procedures going ahead.

The Ohanet project is going very well. This is a risk service contract [RSC] which we signed in 2000 with SONATRACH. The RSC was gazetted in November 2000. The original partners of course were Itoshu and Petrofac and as you know Woodside has farmed in with 15 per cent last year.

This is a big field, 3.2 Tcf, and about 210 barrels of liquids, a combination of condensate and LPG. Liquids production will be about 60,000 barrels a day with BHP Billiton's share being 25,000 barrels a day. Our entitlement to liquids under the RSC terms at current oil prices is 67 million barrels, about 55 per cent of that is condensate, the rest being LPG. Indicative capital cost around about US$1 billion, making our share about US$430 million dollars.

This contract is going very well. All the contracts have been let. Development drilling is underway and facility engineering is approaching 18 per cent complete. The major base camp has now been built and the major subcontracts are underway. We will drill 32 new wells and recomplete 15 previously drilled wells and currently have two drilling rigs on site; a work over rig and a rig testing unit all on site. It is actually a real hive of activity on site at the moment, and hence we are very confident that our first production will be reached in the third quarter of 2003 fiscal year.

Ladies and gentlemen, that brings us to the end of the presentation today. I would like to conclude though by just giving some summary slides, giving you an idea of what we see as our priorities in the short to medium term.

This slide shows our capital slate. On the left you can see the investment in US dollars and down the bottom you can see the start-up date when we expect first oil.

In 2003 you can see down there the yellow dot at the bottom is Zamzama, that's the full field development, we expect to be onstream 2003. Our share is in the vicinity of US$40 million. The second one is the ROD project in Algeria which we also expect onstream in 2003. As I said before, our investment there about US$200 million.

In 2004 we have four projects coming onstream: the Bream A gas pipeline in Bass Strait; the Ohanet project, and we also hope to have Minerva, although it hasn't yet been sanctioned. Subject to finalisation we would expect that to be approved next year. We have an investment there of about US$120 million, BHP Billiton's share. The bigger blob up there is the Mad Dog project which would be due to come onstream about 2004.

2005, North West Shelf fifth train. Angostura [Trinidad] if everything goes to plan could come forward from that, but for our current plan is for 2005. Then the big white one at the top is Atlantis which is going to be a very large investment for BHP Billiton, the largest we will be making in this period of time. Then lastly at the end you will see the fifth train of the North West Shelf which we would expect to be coming on there, and also Kipper [gas and oil, Australia].

So it is quite a slate of projects and I think you will see a good amount of production coming on over those years.

I see we have four areas where we continue to drive forward. The first area is to continue to maximise existing value. This is about making sure that Bass Strait and North West Shelf continue to operate strongly. Although we are not the operator, we do influence and obviously we want to maximise our value. Obviously we will continue to drive our performance in Liverpool Bay which I think has been one of our successes in the last few years.

So maximising the value from our existing assets will be the number one priority. Number two priority will be bringing those projects which we've currently captured and bringing them onstream on time. Obviously the projects in Algeria, the fourth train of the North West Shelf and the Bream pipeline are very important projects for us. Then it is about sanctioning and development projects, Mad Dog, Atlantis, Trinidad, and Zamzama. When you add all of those projects up, when they are onstream at their peak they will provide something in excess of 170,000 barrels a day of production for BHP Billiton. So they are very important projects when you think we currently produce about 360,000 barrels a day; our share in those core projects is about half our current production. They are all very robust projects and if everything goes to plan, and we have them onstream on time, obviously they will add significant of value to our business. So sanctioning and going ahead with those developments is most important.

Finally, there's the blue sky of the future. While we run our business well today and complete the projects we have currently sanctioned, while we also sanction new projects, we hope to continue to pursue good opportunities, and that's about maintaining a quality portfolio. So therefore it is very much about making sure that our growth profile has quality. It is about having meaningful sized opportunities, potentially with a value contribution in the order of a billion dollars. We don't want to spend a lot of time on small projects. BHP Billiton is now a US$30 million plus corporation and obviously the Petroleum business needs to look at projects which have a meaningful size.

Finally, we will continue to keep our geographic focus. In London on Friday I got asked about Russia and Caspian and all sorts of wonderful places. We really do intend to keep our focus very much on the countries we have talked about today.

Finally, I think going forward Petroleum is a very important part of BHP Billiton. It contributes a significant amount to the corporation's profit and I think it has a very good growth opportunity with a number of brown and greenfield projects and it will continue to be an important part of the group. We have a strong portfolio of assets, our production assets are all performing well. We have very good margins, very robust even at low oil prices, and I think our recent exploration success has shown we can make some material discoveries, and extend the pipeline projects going forward.

That's the end of the presentation today. What I would like to do now is throw it open for questions.

Q. You mentioned talking about the Gulf of Mexico this morning that I think drilling is up to nearly 10,000 feet. We have seen developments in Brazil to 6,000. How deep would you be prepared to drill, I suppose, ahead of where technology would allow development?

MIKE WEILL: Actually, from a development perspective, two comments here. One, there isn't a hell of lot of prospectivity beyond 10,000 feet water depth. There are very few feature so there isn't much prospectivity. From a development perspective, we have gone from 1,000 feet to 3,000 feet to 5,000 feet to 6,000 plus and frankly the difference between 6 and 7,500, say, is really minimal. It is the 7,500 to 9,000 and I think you are going to see that with discoveries in the next five to ten years at the most. There isn't much beyond that.

PHILIP AIKEN: I think the industry is driving to bring down the cost of the wells, therefore to some degree when it comes to production we talk about safety, production and cost. I think what has happened now with deep water drilling there is a lot of emphasis about placed on companies about bringing the cost down. Probably going back a couple of years ago you were talking about US$30 to US$50 million dollars, I think people are now talking more about US$20 to US$40 million dollars so therefore there is a lot of work being done to bring the costs down. So I think that is what the industry is doing, trying to understand how these wells can be drilled faster and at less cost.

Q. Can you talk a little bit about the buyback in Iran, can you give us a little more detail on the fiscal terms and how it works, and then, secondly, just looking at the cost performance of the business and how far do you think you can drive it?

PHILIP AIKEN: It is very hard really to say much more about the buyback project in Iran because, quite seriously, we are in the middle of some fairly sensitive commercial negotiations which is really about the financial terms, but the Iranian buyback projects have been around for a while now. There is something like 11 projects which have already been let to about seven companies, and some of the majors have been involved in those projects.

Basically, it is really about giving you a return on the money you invest. The way the buyback projects work is the foreign contractor comes in and contracts to build a facility to a certain price and there is an agreed return on that. Obviously, if the oil price goes down you are protected because you get more oil to make up for what you have been promised by the government. One of the issues which has taken place in Iran is that there was no incentive for companies to do better. If you actually came in under on the capital cost there was no great incentive, and if you actually came and produced more there was no inventive to make more production. So one of the things which is currently being considered by the Iranians at the moment is the terms of these buyback contracts to allow some potential upside.

So I really can't say much more at the moment. It is a fairly basic buyback procedure. It really is about the foreign contractor coming in, building the facility, the facilities that are operated by NIOC {National Iranian Oil Company], and we're paid in oil. The only comment I would say is that these things are probably going to be in the mid teen returns. Certainly the earlier buyback contracts in Iran, some of them were in the low 20s. I think now they have been tightened up, but we certainly wouldn't look at anything which wouldn't be in the middle to the high teens.

On cost base, it is quite interesting. When I first came into this role I thought we had an organisation structure which wasn't as efficient as it could have been. At that time we had a global strategy but we had three regions, so we flattened out the organisation and we now have a global organisation with the assets and resource teams reporting into a global management. If anything, now I would say our overheads are going to increase in the next three years, the reason being we have a lot of activity, we have a lot of projects there for what we have in place, and therefore to some degree I don't think we are looking to reduce our cost base now going forward, we are probably looking at increasing it if anything, mainly because of the amount of project work we have in hand.

When it comes to finding and development costs, we have set ourselves targets. Our internal target is to have an F&D [finding and development] cost of better than US$4.50 and if we can retain an F&D cost of US$4.50 we will be performing in the top quartile of businesses and that is obviously where we want to be.

Q. A question about your gas strategy in South Australia, please. You dismissed pretty quickly the gas for Northern Australia, however there are at least two go projects of a small size coming from the Bass Strait region. In all of these fields you have either a low equity or no equity in, so what is the strategy in regards to the smaller fields coming on line in Bass Strait?

MIKE WEILL: Kipper, in particular, we are looking at very hard. In fact, Kipper is right next to the Pilchard well that we drilled with Esso earlier this year, and basically presents us with a tie back opportunity in the future. We feel that fundamentally Bass Strait is the most competitive gas in the basin. That's not to say this other gas is not going to get up and get contracted. In terms of the farther away basins, clearly the tyranny of distance gives us an advantage,- and the fact that we basically have all of the infrastructure sitting there today gives us one heck of an advantage.

Q. I take that to mean you are not going to chase the others on price for those small markets, and these guys are undercutting them by 20 to 40 per cent to get into the market?

PHILIP AIKEN: Basically no.

Q. It is obvious from the presentation that a big growth area is the Gulf of Mexico going forward. Can you give us a bit more detail, a bit more of a feel for the level of prospects that you have at this stage. Is there still a lot more work to be done? What sort of play types are we looking at? Is it like shooting fish in a barrel, what do you think is going to happen?

TERRY WHITE: If you look at our inventory, we have some good prospects going forward that we are currently working on but there is no doubt there is a challenge to keep the portfolio rebuilt. We are focusing on prospects that are around our existing discoveries, particularly Mad Dog and Atlantis, and we showed a slide that had two or three of those colourful bumps there. Also we are looking at some other play types. One slide I skipped over because it was slightly out of sequence, we were looking at some mid field opportunities around the Typhoon and the Genesis areas. We have about 30 blocks in the Green Canyon area, so we are looking at the smaller prospects which are analogous to Typhoon. Hopefully we can tie them in quickly so they are high margin prospects.

Our ability to image below the salt canopy is a critical technology that we are all involved in. There are relatively cycle times in terms of getting things mature, but I think we are finding those cycle times are decreasing so we have an ability to get things ready quicker.

So I think we have a good slate of opportunities in front of us. They are at different stages of maturity in terms of being drill ready and they have quite different risk profiles, and there is a mixture of potential for both the short, medium and long-term. Clearly an objective of the team in Houston is to rebuild the portfolio. One issue that we didn't discuss, there is an area in the eastern Gulf of Mexico that's been embargoed for the last ten years because of environmental issues. It will be up for bid in, I think, December of this year, so we have work going on with that at the moment. Whether or not we choose to bid remains to be seen, it depends on the prospectivity.

So we will have an aggressive program of working on what we have and building for the future.

Q. Other than Iran, have you looked at other areas where you can work well with Billiton in terms of future growth opportunities?

PHILIP AIKEN: We have looked at a number of areas but nothing really specific. I mean, for example we have had discussions in Brazil. As you know, we have aluminium minimum smelters in Brazil and they have huge issues about shortages of electricity. The last few years their hydroschemes have been quite heavily down. We have done some work helping them look at opportunities that might assist there.

We have really explored a number of areas like that but nothing in particular. One of the things which is said quite strongly about BHP Billiton is we are short and long on energy. Obviously aluminium is a huge user of power and the developments in the refineries have taken advantage of stranded power from Eskom in South Africa.

So going forward I think we will have an ongoing dialogue looking at opportunities like that, but at this point in time probably the major priority of the merger would be the integration. The actual work we did in Iran was really with the old BHP.

Q. Looking at the overall capital budget and exploration budgets in the next couple of years, I wasn't good at adding them all and I fear I have made some mistakes. Obviously they come to very large numbers. How do you relate to that cashflow as well, but some idea for the next three or four years because these projects seem to all be mapping out particularly over the next three years.

PHILIP AIKEN: That fact remains is if you sit down in any area and look at it, on benchmarking, our reserves replacement has probably been one of our least performing areas because we have under invested in this business. Therefore, I think in the next few years we are going to be spending a lot more capital than we probably spent over the last five or ten years in growing the Petroleum business of BHP Billiton.

This is one of the great benefits of being a part of a large group, that these projects can be funded out of BHP Billiton. Obviously these projects are looked at in the total portfolio. If you look over the next five years there is no doubt that Petroleum will be taking a larger share of the capital funding which the corporation is going to be putting forward.

Q. So if I was to look at the exploration budget of about, say, US$250million average for the next four to five years?

PHILIP AIKEN: What we are doing with exploration these days is a little bit more sophisticated than in the past and there has been some work initiated by Greg. What we are saying is we have an exploration budget which is around about US$250 million. Then on top of that we will ask the corporation for extra funds for appraisal and delineation, so we are not trying to squeeze it all into that area and come up with a figure. Every year Petroleum used to go to the corporation, get as much as it could get. What we do now is take a much more sophisticated attitude of a base figure and we go back to the corporation to fund success. Obviously at the moment the Trinidad success was not in our base budget, so we have gone back and made more money there.

So US$200-250million, depending on the success. When it comes to capital, it depends on the projects. They are big projects and you can add them up as well as I can. The underlying investment of the business suggests that to continue to grow a business - we produce about 130 million barrels a year, and if you've got a development cost of $3.50 to stand still you have to be looking at close at a half a billion dollars to just fund your business going forward. That's the sort of figures we are talking about.

Q. I know some of the majors have these production targets --

PHILIP AIKEN: Yes.

Q. Do you have a medium term target? If we are rolling forward three or four years in the plan, looking forward what would be the production rate increase in your mind?

PHILIP AIKEN: I think the slide Greg showed before showed we are producing about 130 million barrels a year now. Five years out, fiscal year 2006 we are looking at about 180 million barrels. That's the target. In this business you can't look at annual targets, you have to look at what is happening over a period of time. That is a pretty bullish target. A 5.5 per cent growth per annum for five years would be very much at the top of E&P companies overall. So in saying that, a lot of things have to go right, so it is a pretty ambitious target but it is one we believe we have to achieve if we are going to meet our goals on time.

Q. Just on the growth going forward there are two areas you are looking at. One is the high return Gulf of Mexico type and the other is the lower risk Algerian type. How do you propose to split that up. Is it 50/50?

PHILIP AIKEN: Good question. It is one we often discuss internally. I think what happens in our case is that we see it as a business where to some degree we are more resource than opportunity constrained. By that I think one of the big areas going forward is not about the availability of money, it is the availability of people.

If you look at the oil and gas industry internationally over the last ten years there is a lot less people involved in the business than there was. We have the issue also of getting the right amount of people. So to some degree we also have to take - before I answer your question - take into account, not just what we can actually do, but what we can physically do going forward.

To some degree to me how much we take in the lower return resource business will depend on how successful we are in exploration. I mean, if we went out and found 200 to 500 million barrel fields every year we certainly would put our priority into those, so I would see that would be a higher proportion of our business. However, we realise that we need a base business and going forward we think it is prudent to have a part of our portfolio in the lower return regulated return type market, but I see it as being a lower percentage than the sort of percentage that we have in the high margin exploration area.

To some degree it is also looking at the longer term. I attended the last OPEC conference in Vienna a few weeks back and it was interesting seeing non-OPEC oil production has peaked and it is suggested that by about 2015 that non-OPEC deep water oil production will have peaked also. If you look post 2020, if you are going to survive in the E&P business, you are going to have a significant part of your business in OPEC type companies. Therefore to some degree I see going into Algeria and going into Iran in a relatively small way, compared what we are doing in deep water exploration et cetera, is a way of really giving ourselves options for the future. I think the opportunity there is really about what you can learn today.

So the answer to the question is we will look at the opportunities as they come forward. Obviously we will take the higher opportunity, the higher margin opportunities first, but we will continue to balance the portfolio and we are also looking at where the opportunities will be going out in the future.

Q. Just to add on that, you mention people being a key factor. How does BHP Petroleum manage to retain all the people in this business when they have the --

PHILIP AIKEN: Yes. It is quite interesting. We have had two examples, I obviously won't go into names or where, where we have recruited people from mega majors who have come into work for us because of the challenge of what we are doing in deep water or something like that. When they come into a company like BHP Billiton Petroleum they actually find they get a lot more freedom and a lot more opportunity to work on projects than being part of a much larger organisation. When a person comes in and has a good experience, they are inclined to bring people with them.

So it really depends on where you are. I mean, at the moment in London it is very difficult because the oil market has been very good and you will find in the UK at the moment it is a very, very tight market. When oil prices start to go down and some of the companies start cutting back, some of the pure players, you find people come a bit loose. We actually find we can recruit people. If a person has a long-term goal to be in a huge oil company they are probably not going to join us, but there are a lot of people who enjoy the variety of the work and the opportunity in a smaller organisation and, in fact, we don't have too much trouble getting the professionals that we want.

Q. Just a question on value. There is a view internally at BHP Billiton that the Petroleum is undervalued.

PHILIP AIKEN: Yes.

Q. I guess the obvious question is where does the group think that under valuation is occurring? I guess when you look at the growth Petroleum went through in the countries Algeria, Pakistan, Trinidad, Bolivia, if that is the area where the under valuation is occurring are investors being too cautious in not giving that full value?

PHILIP AIKEN: I will ask Greg to comment on that as an ex-investment banker and CFO.

GREG ROBINSON: I will sit on the fence. The answer is probably different for every analyst. We look at the values that come out of the community and we see the values that we are able to build up within our own portfolio. When you look at the quantum numbers we can see gaps and it is not consistent across the analysts. I would say that across some of our exploration, certainly around Trinidad and those areas, there are big value differences, but the same has applied for some of our major production assets, too. It is not a consistent answer, I'm sorry, but in general we feel that the market has undervalued Petroleum. Albeit that it has been catching up a bit this year as we have gone through the merger and the analytical community has focused more on the Petroleum division.

Q. I just want to go back to that production growth slide. It seems that a majority of that growth is in the gas part of the business, the oil part of the slide remained fairly constant. I guess one of the things that is integral to that is developing the market to commercialise gas measures. How big a role is BHP playing in the LNG outside of the North West Shelf in terms of commercialising some of that gas flow?

PHILIP AIKEN: I am just trying to remember the slide myself. If you look at that slide gas does grow but of course around about 2004 and 2005 you have Mad Dog and Atlantis coming on, so I don't think gas goes enormously out. I wish I could tell you the figures but going forward we are going to start to develop quite a bit of oil production. ROD is oil, Atlantis and Mad Dog are basically oil although there is gas under both of those, and I think really we would like to see a balance of oil and gas. Obviously oil projects are projects that --

GREG ROBINSON: For example, Typhoon oil, 7 million barrels; ROD oil; Zamzama gas; Ohanet gas, condensate; Minerva gas and then we have Mad Dog, Atlantis, Trinidad all oil. So you are looking at it across Bass Strait and the North West Shelf --

Q. The question wasn't actually --

PHILIP AIKEN: No, it was about LNG.

Q. It was in terms of BHP's involvement outside of the North West Shelf.

PHILIP AIKEN: At the moment our only interest in LNG is in the North West Shelf, but I think we are being quite open in saying we have looked at other opportunities. One of the things we looked at when we first had Trinidad was our chance to get into LNG, but now we have an oil discovery there that is probably less likely.

One of our interests obviously being Iran is the potential for both LNG and pipeline gas out of Iran and we also have other interests in north-western Australia which aren't necessarily with the North West Shelf. For example, Scarborough and the other fields we have there.

So in LNG we certainly would be very keen to do something further. The only thing which worries about me LNG, I am a great believer in the LNG business going forward, I think it will grow a lot in the next 20 years, but it is going to be become a hell of a competitive world. You only have to go to LNG13 this year and see all the brownfield projects but all the greenfield projects; Angola, Bolivia, more projects in Nigeria. Everyone seems to have their eye on a another greenfield LNG project.

I recently went to the World Energy Conference in Buenos Aries and I was staggered to see three LNG projects being promoted there as part of the conference which is very much about power utility.

I think we are a very good partner for someone in an LNG project. We have very good marketing experience, we have good operational experience plus our involvement in the North West Shelf, and we also have some technology which we call Compact LNG which we believe somewhere in the future will have an application.

My view is that LNG will be opportunistic and we will continue to look at opportunities, but I really do have a bit of concern at all the projects people are talking about.

Q. . Just following up about LNG and the profits. It seems to me if this correct (inaudible) commodity at a lower return business. Are we able to sustain the value of the North West Shelf?

PHILIP AIKEN: . It is interesting, there was a presentation in the World Energy Conference from a guy who talked about building an LNG plant and selling it spot. Anybody who does that is going to be a very brave man. I think what will happen going forward is the plants will be underpinned by long-term contracts which might take up half, two-thirds of the volume and there might be more of the spot market developed.

Today about 2 per cent of the world's LNG is sold on the spot market. I think most people think that within ten years that will still only be 5 per cent. The fact remains is there are a lot of people who have more to lose if LNG prices go to a spot commodity basis. So I think the commodity spot market will grow but I think it will still be quite small. I think the projection I saw said it will only be 5 per cent of the market in ten years' time.

What is going to happen is what has happened with us with the Japanese. You are going to go away from the six seller, eight buyer and you are going into individual negotiations and there are going to be more terms and flexibility in the contracts than there was in the past. I think it will be much more marketing driven than necessarily supply-demand driven. I think there will be much more selling done going forward, but I think the chance of it being totally commodity in my lifetime is unlikely.

Q. How interrelated are the two parts of minerals, Iran with regards to minerals and oil and gas commodities? Is there any link between the two (Inaudible) and are you doing the dual track?

PHILIP AIKEN: Actually everywhere we go we now take the opportunity of trying to see if there is some benefit for our minerals, and vice versa. When we went into Angola, for example, we did quite a lot of work with the diamonds people looking for the opportunity of diamonds. When we went into Algeria we actually as part of the bonus contract looked at a couple of projects in Iran, we are not actually going into them together but we are certainly working together. If you are going to do a minerals project in Iran it will have to stand up on its own feet. We wouldn't do it because we are in the oil business and vice versa. So we are not going hand-in-hand but we are aware of what we are doing and working as closely together as we can.

Q. Just on Iran, are there any implications? What are you doing with the Iran sanctions in the US and what is the firm idea on the timing on when the government might approve that deal?

PHILIP AIKEN: Obviously the ILSA legislation has been re-enacted. BHP Billiton has always said we will operate to the letter of the law in the countries we operate in. As you are aware, a number of projects in Iran have been carried out by foreign companies. They have all been given waivers by the US. We expect we have to go through a similar process but our feeling at this stage is that we will be treated equally as European and Canadian companies that have gone into Iran and would not be subject to sanctions, but that is something we will have to address at the right time.

With regards to timing, I am always very nervous on timing on projects. I think we took a year longer than we thought we would to sign the Ohanet contract because the negotiations dragged on, and the negotiations with Iran will drag on also. But the Iranians are very keen to get this project cleared by the end of their current fiscal year which is the end of March, so we hope it would be some time in that sort of period but that would be very much subject to resolving issues.

Q.I have two questions here. The first is obviously you have had a lot of discussions with Woodside and Shell and sort of a merger or corporation restructure is there anything that came out of that may lead to the value being optimised in that part of the business, out of those discussions? The second question really regards the tax credit situation in the United States and whether you have any views at this stage as to how Petroleum may use those, particularly with respect to acquisitions which is something people want to know about.

PHILIP AIKEN: One of the things the North West Shelf joint venture has been doing for a number of years is to try to work out how to increase the competitiveness of the North West Shelf, and there is nothing specifically out of discussions we had with Woodside and Shell which really differed from what we are having with all the partners. So really the answer to that question is basically no.

With regards to tax losses, it has been a big issue for BHP. We have a lot of tax losses in the US and of course one of the things that really helps our Gulf of Mexico projects would be the fact that we won't pay any tax for a long time because of the tax losses we have. Obviously if we do have been acquisition, that again has great benefit because we have capital gains, we have capital losses also. So, yes, those losses are available but it doesn't mean that we go out and do something for doing it sake, it has to be the right acquisition in the US. It certainly helps the underlying performance of the business in the US as we won't be paying tax on Typhoon, probably Mad Dog and Atlantis for a long time to come.

Q. Phil, since the merger with Billiton there has been a lot of unease in the UK market particularly, both on the buy and sell side, about the petroleum business to the mineral business, i.e. if you want oil and minerals buy Rio and BP. Do you think that buying into the argument that the management at BHP Billiton is committed to Petroleum being a long-term investment, and if so how do you think they are going to value this business within the BHP Billiton portfolio?

PHILIP AIKEN: Well, I've been in this role now for about four and a bit years and I think ever since I have been here I have been asked that question pre-Billiton, just as BHP. As I said before, if you look at the portfolio of BHP Billiton oil and gas, it is very good for diversifying your business. If you didn't have oil and gas, the cashflow at risk would be much higher. In Petroleum BHP Billiton has one of the most profitable E&P companies in the world. We are in the top half dozen, top three or four companies when it comes to our return on capital and our operating margins. We have a wonderful suite of brownfield and greenfield projects going forward and, really, the Board and the senior management of BHP Billiton has given me every confidence that they want those projects to be developed and create value for the BHP Billiton shareholders.

So at this point in time I have no suggestions at all that there is anything but 100 per cent support for Petroleum to be part of BHP Billiton for some time to come. That's the attitude I get and that is certainly my own view.

For the people who have come from the Billiton side, they are learning about oil and gas very quickly. They understand the mining business very well and I think they are understanding this business very, very quickly, so I have no issues and don't think it is a problem going forward. The trouble in the UK with all the analysts or the market is they have always followed Billiton as a pure minerals play. I did two presentations, one in April about the time of the merger, and the one I did last Friday and the market in the UK was much more informed, they had done a lot more homework since then, and I think they are beginning to realise Petroleum is going to be part of the portfolio for a while.

Q. How do you think they are going to value it?

PHILIP AIKEN: How are they going to value it, well that's up to them to some degree. I think that over a period of time there will be a lot more consideration taken about what development merits are, and I think you only value Petroleum by the opportunity it has and you have to value it equally to the other parts of the portfolio, therefore I think it is very much about valuing the opportunities and the value of the projects coming forward.

Q. Just in relation to disclosure, the BHP disclosure overall is quite good. I notice in the Petroleum division you have the disclosure of Bass Strait separated out from the North West Shelf and Liverpool Bay and then Other. Given the growth of the other areas, particularly in the United States, but other areas as well, North Africa coming up, will there be added disclosure?

GREG ROBINSON: Good question. We are looking at that at the moment in making sure that the way we are talking about the business and where the growth is that we are looking at disclosures and alignment. I can't give you an answer right at the moment, but we are going through an active process of looking at the breakdown of information, making sure that the investment community gets access to the right information.

Q. I think just in regard to that, given the large sums that have been expended, in particular the Gulf of Mexico keeping apace on that and going back into the (Inaudible) would assist. The second area that I wanted to explore, just in relation to Gulf of Mexico forecast of costs, I am just trying to find the chart, there was a section here on gas and gas quality. I am just wondering, it seemed like a very big number to me. Quality and gas content, and the indicative margin analysis. I didn't quite understand.

MIKE WEILL: ThatUS$2.92 cents is what it costs to get the barrel of oil from the well head on the platform to a WTI equivalent on the beach. So it is the transportation tariffs to move the oil off the platform on to the beach, as well as the gas transportation. That is all involved. It is gravity corrections, it is transportation tariffs.

Q. Because I saw OPEC's transportation was mentioned in another section.

PHILIP AIKEN: It is like all of these things, if you add them up you are talking about US$5 to produce and transport, you have quality issues, it depends where you sell it. They are real costs. But it is not a US$2.90 discount because it is poor quality crude, that is the point you are trying to make. It is not.

Well, ladies and gentlemen, that brings us to a close today. Thank you very much for joining us and we look forward to seeing you again some time in the future. Thank you.