Petroleum Investor Briefing
5 October 2016

Transcript

1. Petroleum Overview

STEVE PASTOR, PRESIDENT OPERATIONS PETROLEUM: Okay, good morning and welcome to BHP Billiton's 2016 Petroleum Investor Briefing. For those I have not met, I am Steve Pastor, and I was appointed to the President of Operations petroleum position back in February earlier this year. I previously held the position of the Asset President for our Conventional business and, prior to that, several leadership roles across conventional, shale and deepwater developments. Before joining BHP Billiton in 2001, I worked for Chevron for a little over 11 years and had the great pleasure of working on some of their first deepwater developments in the Gulf of Mexico.

Now, it is a pleasure to be here in London and with those of you who are connected by webcast and teleconference to provide a detailed overview of our petroleum business. Before getting started, I want to point to our disclaimer, which is obviously going to be relevant to our conversation today, and also to our second disclaimer, which relates a little bit more specifically to our petroleum resources.

Okay, now, let us get started. BHP Billiton Petroleum is a strong business on a foundation of quality assets that have produced strong operating and financial performance over many years. While global markets are currently well supplied, fundamentals indicate that markets are rebalancing in both oil and gas in both the short and the mid run- actually ahead of our other mineral commodities. Our strategy is focused on value over volume. Our significant reduction in activity in capital investment, over the last three years in particular of lower prices, demonstrates that we will be both patient and prudent as we work to unlock the significant potential from our oil and gas assets.

Our teams have done an excellent job reducing costs and improving capital efficiency. We will take you through several remarkable examples today of performance improvements and cost reductions that we have achieved. We will describe our momentum and our plans to continue to safely improve productivity going forward. This strategy and our operational achievements have further increased the economic competitiveness and the potential for both our shale and our conventional assets. Lower operating costs and capital costs have improved the rate of return, not only by reducing our costs but by improving rates and recoveries, which has lowered our breakevens in our shale portfolio in particular.

Today, we will show you how we have increased that investable inventory and we will also show you how we are prudently managing investment flexibility to adjust for market conditions. Our shale assets are now generating cash at current prices, and they have significant upside, should oil and gas prices improve, as we expect. Our portfolio of conventional brownfield extension projects is economically robust even in low-price scenarios. And, with significant improvements in capital efficiency, major capital projects – for example, the Mad Dog 2 major capital project – are now economically attractive even well below $50 a barrel. Our conventional deepwater exploration programme, which is focused on Tier-1 oil in bases that we understand both geologically and economically, offer great potential for value. Now, we will talk more about exploration progress, as well as potential volumes and value, a little bit later during the programme.

And, finally, while our primary focus is on delivering against this rich opportunity set, should attractive assets become available at the right process, we would consider inorganic growth opportunities if they are strategically aligned and they offer value-accretive propositions for the corporation.
Now, you can see some of our petroleum leadership team here on this slide today. It is a team of highly capable leaders with proven performance and deep functional expertise. Our experience is connected across the globe, in conventional, and shale through exploration, development and operations. While our petroleum line leaders are primarily responsible of safety, volumes and cost, we are supported by deeply skilled and experienced functional teams that are aligned globally across BHP Billiton. This operating model enhances our ability to safely deliver both orthopaedic productivity and capital efficiency though the elimination of duplication and the enabling of rapid transfer of skills and knowledge between our minerals and our petroleum colleagues.

We are harnessing the power of BHP Billiton's people, systems, processes and our culture for continuous improvement and best-practice sharing. Although we are still early on in this stage of organisational optimisation, we are seeing that the quality and the timeliness of our functional support and our decision-making is higher in every area, from HR-led talent management and leadership development programmes to strategy and finance, which are now solidly connected to our CFO to ensure we make the most effective, timely, consistent decisions on the allocation of capital. This organisational structure is not only more effective at leveraging functional expertise and best practice, but is also leaner, lower-cost and, ultimately, more scalable.

Today, several members of our leadership team have joined me to describe our plans and our vision for the petroleum business. Michiel Hovers, our Vice President of Marketing, will provide a perspective on the compelling outlook for both oil and gas. Michelle Turner, our Vice President of Finance, will describe petroleum's financial performance and our continued drive for productivity. Maybe most importantly, she will describe how BHP Billiton's disciplined capital-allocation framework is applied in petroleum. Alex Archila, our Asset President for Shale, will take you through a nice deep dive in each of the fields we have across Shale, and he will explain both the quality and the value of these assets – and the relative value of these assets, and their potential to generate both significant returns and free cash flow going forward. He will also discuss the flexibility that we have and how we will apply that to adjust to market conditions. Geraldine Slattery, our Asset President for conventional, will describe the strong foundation of the portfolio of conventional assets we have and the economically robust pipeline of opportunities we have, both brownfield and greenfield, to production and cash flow not only over the next five years but also well beyond. And, finally, Niall McCormack, our Vice President of Exploration, will take you through a focused exploration strategy to discover and deliver the next portfolio of Tier-1 assets.

Now, we all know that it has been a challenging period for the oil and gas industry, but what I am confident that you will see today is the dynamic and commercial way that our leadership team is approaching this business. We are flexing all the levers we can to improve safety, maximise value, increase returns and, ultimately, generate significant free cash flow.

Petroleum has been and continues to be a very significant contributor to the BHP Billiton Group, particularly by way of financial performance. We generated underlying EBITDA of almost $4 billion last year, and that represents roughly a third of the EBITDA generated across the BHP Billiton Group. Interestingly, that is pretty consistent with our average contribution over the last five years – and even further back. Petroleum's EBITDA margins of 66% over the last five years are the best in the BHP Billiton Group. Interestingly, last year petroleum generated 54% EBITDA margins, even with significantly lower prices. Maybe more importantly – and not shown on the slides here today – is that petroleum's cash generation of over $800 million last year and almost $13 billion in the last five years reflects the quality of our portfolio and, ultimately, supports the stability of the BHP Billiton Group.

Petroleum's portfolio of assets is high quality and it is well aligned to the overall BHP Billiton strategy: to own and operate large, long-life, low-cost, expandable upstream assets. Look, we are a natural resources business – just like our minerals peers and colleagues – that is founded on excellent geology, engineering and understanding of markets. We succeed when we are most effective and most efficient at finding, developing, producing and delivering those resources in the safest and most cost-effective way. Our Petroleum business benefits greatly from the expertise of our minerals colleagues across the wider organisation, including sharing of talent, sharing of ideas and leveraging of best practice, again, in technical functions: geosciences, engineering, operations and maintenance, project development, investment decision-making, as I described before, and so on.

This sharing between minerals and petroleum goes both ways. Petroleum also diversifies exposure to markets and political jurisdictions. It provides financial diversification, which is recognised by our corporate credit rating and, in turn, lowers our funding costs. Petroleum supports and contributes to the company's strong balance sheet, and it is that strong balance sheet that enhances our ability to consistently invest, for example, in Tier-1 exploration, when it makes good business sense to do so – and we will talk more about that during the programme. But the true power of Petroleum, being part of the world's largest mining company, may be the differentiation and the diverse set of opportunities we enjoy when compared to pure-play oil and gas peers. We do not face the same constant pressure to chase volumes and replace reserves, even at a time and place when it does not make sense to do so. Finally, when we look across all of our core commodities and we analyse fundamentals across a range of scenarios, we expect oil and gas markets will rebalance first.

Now let me turn to a quick outlook on the markets. Global energy needs are rising, and by 2035, global population is expected to increase by 1.5 billion on the planet, and GDP is expected to double. The graph that you see here on the right hand side of the chart – the source is the International Energy Agency – is consistent with our own analysis, and it shows that on the back of increasing populations, urbanisation and improving standards of living, the world simply needs increasingly more reliable, low cost and clean energy. We test across a range of possibilities, and our models show that oil and gas will unquestionably contribute and play a very important role in the overall primary energy mix, even with expected advances in energy efficiency and renewables in particular. Even with that, fossil fuels will supply four fifths of the world's primary energy needs through 2035. That is enormous.

Environmental, operational and economic advantages of natural gas enable it to be the fastest growing fossil fuel, established to be at about 2% compounded annual growth rate. With globally expanding transport and petrochemical sectors, oil demand is forecast to grow at about 1%. Renewables are projected to grow quickly – no question. But they are also clearly starting from a very small base.

In the oil market, a shift in fundamentals is already underway. We all know that 2015 was a particularly difficult year for oil and gas producers, as supply outpaced demand by roughly 1.5 million barrels a day, causing commercial inventories to swell and prices to plummet. This year, however, prices have already begun to shift. While OPEC production is at record highs, we also see that they have limited spare capacity. Non-OPEC supply is on the decline due to the significant cutback in activity and the unprecedented deferral of capital. And that historic pullback of investment around the world has brought us closer to balance in 2016. But we still have a minor supply overhang this year, relative to demand. However, in the short run, we expect continued healthy demand and limited supply growth and, on balance, we expect global inventories will start to decline in 2017.

In the long term, the fundamentals remain attractive. As you can see from the chart in the lower right, demand is expected to grow at about 1% per annum over the next two decades. In addition, natural decline, which you see in the blue wedge, declining at roughly 3-4 million barrels per day per year, creates a substantial supply opportunity.

Based on our understanding of remaining global supply, we see the new production coming from three primary sources. Production from OPEC members alone will not be enough to fulfil the supply opportunity. In the US, beyond the mid run, we actually see a reasonably steep cost curve, once the finite sweet spots in the best of the old shale plays have been developed. As a result of that, we actually see upward pressure in terms of the price curve, as those sweet spots are developed out. Other non-OPEC sources will be called on to meet the remaining supply opportunity. We will break that down a little bit further in Michiel's presentation, but when we look at that we see that higher prices are required to induce that new supply.

Now, on shifting to gas, in the US, gas markets have already started to rebalance. Following 2015, a year with oversupply and the mild weather we saw last winter, we had significant excess capacity in inventory but strong summer power burn and declining production has contributed to improving fundamentals. Prices are already recovering from 6-8 months ago, when they were $2 per mcf.

We are expecting that they will continue to rise moderately into accounting year 2017, while the abundance of low-cost supply will likely cap significant price upside in the near term.

In Australia, gas markets are a bit mixed. There is strong demand in Eastern Australia on the back of Curtis Island LNG plant start-ups, but relatively flat Western Australian demand, alongside significant new supply from major fuel start-ups like Gorgon. In the long-run, gas and LNG demand growth is reasonably strong, but heavy investment in LNG over the last decade in particular has led to excess supplies that may take about a decade or so to balance out. Our gas assets are geographically well positioned to meet the growing demand. Our Australian gas will benefit from close proximity to Asia and our US gas can supply increasing demand from the US and Mexico, as well as increasing LNG export capacity. We do, however, see more upside potential from oil than we do from gas, as gas resources are relatively abundant, easier to find and develop and, hence, have a flatter cost curve.

Our strategy is focused on Tier-1 assets in areas where we have both a material position and bring a competitive advantage. Our portfolio is concentrated in Australia and the US, with significant growth potential in Trinidad and Tobago on the back of potential exploration success there. We are continuing to optimise our portfolio, with an aim to hold and run Tier-1 assets that play to our strengths and our competitive advantages, in deepwater conventional and onshore US shale in particular. Our strategy is also to continue to rebalance towards oil, following successful divestments in Liverpool Bay and in Pakistan. We are advancing a farm-down opportunity of some of our interest in the large Scarborough dry-gas resource in Western Australia. We are preparing to market some parts of our large US onshore gas position.

From a growth perspective, we are pursuing conventional oil guided by our extensive global endowment studies in regions that we know both in terms of geology and above-ground risk where we have an early-mover advantage and we can capture material, high-value positions with reasonable competitive and stable fiscal terms that offer competitive returns on investment and ultimately material value to our shareholders. We are advancing an exciting and material exploration programme in Trinidad and Tobago, in the Gulf of Mexico and in Western Australia's Beagle Basin. We are also excited about deepwater Gulf of Mexico opportunities on the Mexico side of the water. Look, from a subsurface perspective, the opportunities on the Mexican side of the border, particularly in the

Perdido trend, are like those we have been pursuing and producing in the US Gulf of Mexico for some time. We will looking closely at opportunities to participate in upcoming exploration and, also, discovered resource bid rounds in early December.

We also continually evaluate other Tier-1 oil acquisition opportunities, again where they are strategically aligned with our strengths and our competitive advantages. But let me be clear: we will only pursue those where there is clear value to BHP Billiton.

Now, before talking more about our assets and plans, I want to start with our performance and our commitments to Sustainability. At BHP Billiton, safety always comes first. We are recognised as one of the safest companies in the industry, and you can see the data that has been sourced externally about our performance relative to peers in terms of lost time and injury—frequency rate. Our total recordable injury-frequency rate last year dropped by 26%, year-on-year, and we are very proud of that performance. And, at the same time, we know we can do better. We are not and we never will be complacent: this is simply not enough. And we will aim to continue to aim to eliminate injuries in the workplace. We are particularly focused on eliminating risk that has the potential for serious harm.

Now, it is also important that we contribute valuably and meaningfully to society and communities where we operate. BHP Billiton recently published our Economic Contribution and Payments of Governments Report for 2016. Last year our total economic contribution across the BHP Billiton Group was $26.7 billion. During the last decade, we have paid approximately $85 billion in taxes and royalties around the world. More specifically in Australia over the last decade, we have paid some AUS$65 billion in royalties and taxes – so extraordinary contributions.

In fiscal year 2016 alone, we directly invested $179 million to support local communities, particularly focused on health, education and the environment. Now, on the slide here, you see petroleum-specific fiscal year 2016 community contributions. Then, finally, we are highly committed to environmental sustainability. We accept the IPCC's assessment of climate change science, and we believe that sustainable development requires reliable, affordable and also clean energy. We believe this requires a significant reduction in global greenhouse gas emissions. We are taking action in many ways, including reducing our own emissions but also through partnerships with industry, governments and academia to accelerate development of low-emissions technologies, particularly such as carbon capture and storage.

Now, let me shift to talking about our assets. We have learned a lot since acquiring our onshore shale position. I will be the first to acknowledge that, clearly, we did not get the timing right. However, what we did get is some of the best positions of the best shale plays in North America: in positions like the Black Hawk and the Eagle Ford, like the core of Haynesville that we have, the core of the Delaware Basin and the Permian. If you look at heat maps sourced from Tudor, Pickering, Holt & Co. or Wood Mackenzie or others, and you draw a line around our position in those plays, you will see that we absolutely have captured the sweetest parts with the lowest breakevens and the best returns on investment in the best North American shale plays.

While, to the outside world, much of this has been masked by the falling oil and gas price, our performance in developing these resources has beaten even our most optimistic expectations from a few years ago. For example, some of you joined us in 2013 at a similar investor conference. Let me tell you that in the Eagle Ford, since 2013, we have lowered our drilling cost from over $5.5 million on average per well to under $1.5 million on average per well. We have reduced our drilling time there from about 30 days on average per well to under nine days per well. That is extraordinary. In addition, better technical characterisation, lower costs and improving rate and recovery performance from longer laterals and bigger completions have all contributed to lower well breakevens and, ultimately, increasing investible well inventory.

The illustration you see on the lower right-hand side of this slide shows just how significant the improvements have been over the last six months alone. The light-blue column you see reflects what we showed in May earlier this year at the Bank of America Merrill Lynch conference, and the dark blue shows how that has improved in the six months since then, with well over 2,000 net wells that have the capability of delivering internal rates of return of 15% or better at $60 per barrel oil and $3.50 per mcf gas.flat real prices below. Now, Alex will break this down field by field a bit later and also talk about just how significant the investible inventory is even at today's spot price. But, clearly, you see the performance improvement is extraordinary and continuing.

As we have relentlessly worked to become stronger, we have also become fitter by right-sizing our organisation for current activity levels, but, along the way and at the same time, we have retained the skills and experience we need to be scalable. As I said earlier, we are focused clearly on value over volumes, and we pulled back hard on activity in investment due to market oversupply and low prices. We are now well placed to invest for value as prices recover. Because the majority of our acreage is held by production, we control the pace, which allows us to be patient while markets continue to work off excess supply and prices continue to recover. Ultimately, that enables us to deliver maximum from our position. In close coordination with our CFO and our Marketing team, we are applying greater capital discipline and flexibility to move quickly as conditions warrant.

We recognize that investing for high prices but instead ending up with significantly lower prices is a risk. I just want to be clear that we are alive to that risk, which is being mitigated in a couple ways. First, we now allocate capital more regularly and formally with a quarterly process, connected again with our CFO and our Marketing teams, using the latest intelligence and robust signpost analyses. We have fewer take-or-pay contracts with rig operators and pipeline owners. We can adjust our investment plans more flexibly and quickly than we are able to in the past.

Second, we are using gas price hedging and advancing development of the core of the Haynesville. That reduces risk of falling prices. Now, oil-price hedging is less attractive given the price upside that we see – but also given the fact that our geologic advantages in the core of the Black Hawk, the Delaware Basin and the Permian make attractive returns even in low-price scenarios. Therein lies the difference.

In conventional, we have a portfolio of quality assets that deliver stable volumes and high margins. We bring deep experience and competitive advantage, particularly in deepwater. That is an area we all know is typically dominated by the super-majors. Our unit cash costs are among the best in our peer group, and we are expecting approximately $10 per barrel of oil equivalent over the next two years. Overall, we generate superior margins in this less competitive arena. We have a comprehensive portfolio of brownfield conventional projects that help offset natural decline in existing fields. These brownfield projects are very economically robust, and they have average rates of return of approximately 45%, which goes a long way to demonstrating the high quality of these infrastructure-advantaged opportunities, and these projects are also robust across the range of consensus prices.

We have deep, proven experience delivering deepwater developments in remote offshore environments. With faster drilling times and lower overall average development costs, we are among the most competitive in the industry in that arena. We are particularly excited about the Mad Dog 2 project, which we expect to bring to our Board for sanction within the next six months. Geraldine will elaborate a bit more this morning on that exciting project.

Now, as I said earlier, divestment of half our stake in the Scarborough project helps us rebalance our portfolio towards oil. With Exxon-Mobil as operator and Woodside a potential partner, we are working to optimise Scarborough development plans to ultimately maximum the value from that asset. Although our conventional base, brownfield, and greenfield programmes are strong, extending our high-margin conventional oil resource position is absolutely core to our strategy and it allows us to capitalise on our expertise and our proven competitive advantages.

Our exploration strategy focuses on early access to Tier 1 liquids opportunities with high working interest and operatorship. Based on our global endowment studies, we have positioned ourselves in key focus basins around the globe. In the Gulf of Mexico, we have two material plays: one that is near Shenzi, where development cost will be advantaged by existing infrastructure; and one that is the western Gulf of Mexico, where we have established a very large position that is concentrated in what we believe is the best part of the Paleogene play. Niall will also, clearly, describe that position, but he will also describe the low cost ability that we have had to capture the position over the last couple of years.

In the Caribbean, we are testing our dominant 'first mover' acreage position; it is a very large position. The Caribbean is actually four times the size of our entire Gulf of Mexico portfolio, which is extraordinary. We have high equity interest and we operate across that entire Trinidad and Tobago deepwater position, alongside the strongest and most credible oil and gas companies in Trinidad and Tobago: Shell, BP and Repsol.

In Western Australia, we have accessed a dominant high equity interest and operated position of approximately 25,000 square kilometres over the largely untested Beagle sub basin.We are maturing our Volume, Risk, and Value work, with an aim to deciding what our next steps will be by the end of this fiscal year. While we recognise the risks of early-phase exploration, we are optimistic, informed by detailed pre-development planning work that we have done, which demonstrates economic viability at $50/bblon the back of exploration success in our made case. That is important. Let me say that one more time. We are confident not only because of the geoscience and rigour from our global endowment studies and our approach to exploration, but we are also confident that, based on detailed development planning, we can develop these fields on the back of exploration success that are economically robust at $50 a barrel. And we have plenty of experience doing deepwater developments of that type.

Beyond exploration, we are continuing to evaluate Tier-1 acquisition opportunities with a primary focus on areas we know well that offer value and fit our strategy, but they must also compete for capital effectively under our capital-allocation framework.

Pulling all of this together, I am confident that we have a strong future for our Petroleum business. Petroleum benefits from and contributes to the significant value of BHP Billiton over the long term. This business will deliver substantial future free cash flow that contributes to the diversification and the stability of our corporate financial results. Further, with an attractive market outlook, we are well placed to create significant value for our owners. We have quality resources and we have proven operating capabilities in both our onshore US business, where our productivity programme continues to drive even lower breakevens and positions us to generate solid investment returns and positive free cash flow under a variety of price scenarios – and Alex will talk more about that, across a range of scenarios, later this morning.

Our conventional assets deliver some of the best returns on investment of any company in our industry and any business within BHP Billiton. Our reliable conventional production profile is supported by economically robust extension opportunities. We have a number of investment opportunities to drive valuable growth in this business.

Later today we will talk more about major growth projects that contribute to that like Mad Dog 2 and Scarborough. Our focused exploration programme has positioned us in some of the most prolific regions in the world with multiple drillable prospects and encouraging results to date.

Finally, I will say this again: we are primarily focused on delivering a rich, organic opportunity set. At the same time, we continue to look at value-accretive Tier-1 oil acquisition opportunities that can help us extend our high-margin portfolio and, ultimately, ultimately build on our existing position of large, long-life, low-cost assets – but we will only look at Tier-1 assets that compete effectively against other opportunities in the portfolio and that have a clear value case. Again, they must compete successfully against the other opportunities across the BHP Billiton portfolio, not just within petroleum, which actually presents quite a high hurdle for investment.

With these organic and potentially inorganic investment opportunities, as well as those across the Group in our other businesses, we will use our capital-allocation framework to guide our investments and, at the end of the day, produce maximum potential value from our opportunity set.

Thank you. Now, I would be happy to take questions. Just by way of housekeeping, on the questions, we have a couple of folks in here today who have microphones, and they can field questions in the room. We also have the operator, who is going to give instructions to those who are connected via teleconference and webcast, and we will try to some balanced alternating between taking questions in the room and questions from the line.

2. Questions and Answers

MENNO SANDERSE, MORGAN STANLEY: Morning, thanks for the details. I have one question regarding the chart on the volumes, which really looks very good, but what a chart does not show is how much the company expects to spend to keep those volumes there. Can you give us any more detail on what kind of investment you expect over the next five years to get to your points for 2020 and 2035?

STEVE PASTOR: I think in the appendix we may have given a little bit more forward-looking guidance on investment. I can tell you what we have guided in fiscal year 2017; it is a pretty low spend: $600 million on US onshore, $800 million on conventional and a $700 million exploration programme. However, I would have to take some advice from our IR folks as to how much specific guidance we have given beyond that.

JASON FAIRCLOUGH, BANK OF AMERICA MERRILL LYNCH: Could you help me understand your policy and your approach on hedging a little bit more? If I think about BHP, historically it has not hedged at all in the minerals business. We seem to be evolving towards more hedging. You were talking about hedging in Haynesville. Does it actually make sense that when you allocate capital, particularly in the US onshore, that you just hedge everything as you allocate the capital to lock in those returns.

STEVE PASTOR: That is a good question. We get that one very often. I will say one thing and then I would ask you to hold off a little bit, because we are going to describe that policy and our approach to hedging a little bit more completely during Michiel's presentation. What I do want to say, however, is that it is very specific to US onshore gas. And we will describe how, with the particular production profile that we see form investing in onshore US gas wells, it makes sense for us not to mis-time that and potentially destroy value. It is very unique, and it relates not only to that production profile but, also, our expectation of a relatively flat cost curve – hence we do not believe we are giving away significant upside there.

SYLVAIN BRUNET, EXANE BNP PARIBAS: Morning, just looking at the very same charts, volume seems to be going down again in 2018. I was curious to know whether you could help us quantify the rate of depletion in the conventional part? If you could give us a sense of the controllable cost potential. You have seen the portfolio after the good number last time. It was seven or eight million or so. What is the potential in 2017/2018?

STEVE PASTOR: First, speaking to the decline, let me just reinforce this, if I have not done it well enough so far. Going forward, our plans are focused on delivering maximum value over volume. Markets continue to be well supplied this year and we expect they will be coming into balance next year and prices recover.

For us, it makes sense to pull back on investment, allowing those volumes to drop some this year, potentially next, but we are going to be very flexible as to how we go back into the core parts of the Permian in particular and the Eagle Ford, which are quite flexible and throttle-able to actually turn that around and, further, using tools to help us invest in our very large portfolio of gas-resource opportunities. That is a snapshot of one scenario. Through that flexibility I just described, we can flex that one way or another. I think that addresses what you are asking about our production decline.

In terms of more specific numbers as to what the decline is in the conventional portfolio and the shale portfolio, I would ask that you let us field that outside of here and we can give you very specific numbers.

Let me take one, if I can, from the phone. Let me alternate a little bit here.

DUNCAN SIMMONDS, BANK OF AMERICA MERRILL LYNCH: Hi, good morning. I wondered whether I could ask a question regarding you 2P reserves. It seems like there is almost a 30% reduction in 2016 versus 2015, and I wondered whether you could talk us through the where's and the whys. That is the first one.

The second is this. It seems like you had some success at Caicos at a high level. Could you please explain what that means and what we should think that means for the next steps?

STEVE PASTOR: Duncan, thank you very much for the question. Unfortunately, the audio quality is not very good. I caught some of that. Let me try to address what I think your first question was, and maybe I will have to ask you to repeat the second. I think the first related to decline rates in US onshore shale – or was it 2P reserves?

DUNCAN SIMMONDS: Yes, 2P.

STEVE PASTOR: Well, look, Duncan, Alex, in his presentation, is going to break down our resource estimates, field by field, category by category. He will talk about proved, probable, 2P and he will talk about 2C prospective resources. I think you will get a whole lot greater insight than I can possibly provide for you at this very moment – and we will have another Q&A opportunity on the back of Alex's presentation for you to maybe dive down into that question a little bit more. What was the second part of the question?

It was success at Caicos, was it not? Look, we announced today that we did encounter oil. I do not remember what the release said, but we encountered oil on multiple horizons at Caicos – not dissimilar to what we found at the Shenzi North well. We are very encouraged by that – so much so that we have actually taken the decision to move our Deepwater Invictus drill ship to that area to do a follow-on appraisal well that we are calling Wildling, which we think will be the test to determine commerciality of the Shenzi North mini-basin. We are very excited about that, and Niall can elaborate a little bit later about not only why we are happy to have found oil in the multiple horizons, but, potentially, why the pressures that we have found suggest connectivity across the play.

PAUL YOUNG, DEUTSCHE BANK: Hi, Steve. I have a few questions on the US onshore. First of all, you say you have the best parts of the best places, but you only have 50,000 net acres of Black Hawk and 100,000 net acres of the Permian. Therefore, you just have 3-5 years of drilling in those fields. My first question is, how can those assets be Tier 1, as they are not long life?

My second question is, as you are short acreage, are you prepared to buy more acreage in those fields for the right price? If not, why not dive in, if you get a good price?

STEVE PASTOR: Paul, thank you for your question. For those who might not have heard that very clearly, Paul's question is about the size, the materiality and the running room of our shale positions, particularly in the Black Hawk and the Delaware Basin, and about the potential value and the options to monetise that value, if you will, whether it is through purely developing our own versus potentially divesting.

First let me just address the potential running room that we have there. I will start in the Delaware Basin, because I think it is the most compelling. In the Delaware Basin, we have about 100 or so producing wells that are producing about 30,000 barrels of oil equivalent per day. Across that position, we could see our way to, potentially, 1,000 or maybe more potential investible locations. Part of the reason is not related to the aerial position we have there, but also relates to the multiple perspective horizons in the Delaware Basin.

Today, Alex will describe for you that we are concentrated on the most economic horizons, the upper Wolfcamp, but we see significant productivity and performance potential – and ultimately value potential – from the middle Wolfcamp and the lower Wolfcamp. There is a lot of running room there and, again, we will talk about investible locations and growing that business into a 150,000 barrel a day business in the mid run, basically. That is our mid-case expectation. There is a lot of running room there.

In the Eagle Ford, it is a slightly different game. What I would say is that the core position of 50,000+ net acres in the Black Hawk part of the Eagle Ford is unquestionably the best value in the entire Eagle Ford play. And the Eagle Ford play is 400 miles wide by 50 miles north to south. It is an enormous position, but the best of that is right there in the acreage that we have. We have developed that quite rapidly over the last several years, and our game there today is to unlock more investible locations. What you see us doing with the one rig we have running in the Black Hawk today is drilling staggered laterals, and we are also doing completion trials, which basically help us improve surface performance, i.e. rate and recovery from the remaining investible locations.

That is in the primary target of the lower Eagle Ford. Although it does not have as many prospective horizons as we see out in the Delaware Basin and the Permian, it does have other prospective horizons, particularly the upper Eagle Ford, which is still largely in appraisal mode, as I call it. We, together with our partners and other operators which are neighbours, are testing the prospective upper Eagle Ford alongside some of the completion-trial work we are doing, with the hope and expectation – Alex will show this in one of his charts – that that opens up hundreds of investible locations across that position.

The second question was about how we monetise for maximum value. Are we a seller? Are we a buyer? How do we actually play that? The short answer I will give you in that space is this: to be strong as a player in US onshore shale, you have to be constantly in deal flow. You have to very thoroughly understand the technical aspects of the opportunities and their economic potential. You have to be rigorous with that and have good confidence in your evaluation across a range of scenarios, both technically and in terms of price. We do that, and we keep it current. We are in deal flow. A bit later, Alex will describe how some of the most recent land deals that we have done have increased the value of our position by trading and swapping positions, so that we aggregate our position and we can more effectively develop that position with fuel wells and longer laterals to recover the same resource. That is tremendously valuable.

I will take another question here in the room.

ANNA MULHOLLAND, DEUTSCHE BANK: Slightly connected to what you were just talking about, I think I heard you say you are preparing to market some of your onshore acreage. Did I hear you correctly? If so, what is for sale? Also, what is the process and the timing of that?

STEVE PASTOR: Thank you, Anna. Yes, we are. When Alex goes through his presentation, you will see the significant resource that we have onshore US. I have talked about our desire to rebalance towards oil, so this position that we are taking and effort that we are making to market some of the longer-dated gas options we see in our US onshore shale position is really about accelerating the monetisation of otherwise long-dated gas options, if we were to hold and develop them on our own.

Now, these are valuable assets. At the end of the day, we are going to go out and market these positions. If we can achieve what we think is fair value for the asset – or premium, which is what we really hope for – then we divest. If we do not achieve that, we will not divest. We have demonstrated our resolve in that regard by going out and marketing the Fayetteville – that was a couple of years or so now – and we did not achieve what we thought was fair value for that asset, and we pulled it down.

I just want to be clear about that. But Alex will talk about how, in the southern areas in the Hawkville, for example, and away from the sweetest part of the Haynesville, we are going to consider bundling up some of the acreage there and testing the market to see whether others are more anxious and interested and find that more investible in the near term than we do.

Part of that investability in the near term is a function of competitiveness versus other locations we have. You have to think about that in the context of the very large, very long-life resource potential we have in US gas, and it is just one way that we can accelerate monetisation of things that are not first in the queue for us.

FRASER JAMIESON, JP MORGAN: Hi, I have a couple of questions on slides 12 and 13. Firstly, on slide 12, the investible inventory, you have obviously seen a big increase in the lower than $50 barrel segment there, but, looking to the right-hand side of that chart, though, the $60-70 a barrel portion, what scope do you have to move those wells down the cost curve? There has not really been a huge change in that number versus the figure six months ago. Is there still work going on there? What are the opportunities to move that down to the left-hand side of that chart?

Secondly, on slide 13, around the Conventional business and the scenario there where it points to lower production in FY2017 and FY2018, I recognise those are scenarios only, but could you maybe give us some more context around what those scenarios envisage in terms of pricing and unit costs?

STEVE PASTOR: Sure, sure. To your first question, I would say that it is going to be a combination of getting our costs down and increasing rate recovery. Those, aside from price, are going to be the most influential on the outcome in terms of economic returns and value creation. There is no question about that.

Without looking specifically at that chart, I actually did not segment it in the way Alex is going to segment it in his presentation; you just see one big block. What Alex is going to share later is what part of that block relates to the Eagle Ford, both the lower and the upper, what part of that relates to the Permian and Delaware Basin etc. You will get a better perspective of what that block that is over there in the $70 a barrel range is made up of, and then we can talk a little bit more specifically about what is happening in that area and where we see the potential.

It is a combination, however. It is not just getting our drilling done faster and bringing our completion costs down. There are other things that help us optimise the ultimate development plan that relate, particularly in the Permian, to optimising the midstream. We are still early in the life cycle of developing out the Permian, and we are working to optimise how we want to go about developing that midstream. That will play a big part in the ultimate economics of that huge, 1,000+ well inventory we have there to deliver into the future. There are lots of things, however. The technology is probably leading the Group in terms of completion technology. We see bigger jobs and higher fluid rates and things like that really unlocking that, but there really are many things. Let me hold that for Alex.

The second question was around our conventional production profile, I believe.

FRASER JAMIESON: Yes, and specifically you talk about production scenarios based on expectations on pricing and cost etc.

STEVE PASTOR: Yes, clearly, the flexibility we have in the onshore US is an order of magnitude higher than the flexibility that we have in conventional. When you make a decision to move forward with an investment, generally, particularly on larger conventional development opportunities, you make that investment decision and it is long-cycled. Your ability to flex that in the near run is a lot lower. There are some examples where it is a little bit different: for example, where we are drilling in-fill wells. We have a rig running at Atlantis today; we have a rig running on the spar at Mad Dog as well. Our decision to continue to move into that and maybe bring more rigs into that could flex that up or down. Right now, I would say that the expectation that that moves around significantly is a lot lower than the expectation that we could throttle either faster or slower into US shale.

FRASER JAMIESON: I am sorry. I am not sure I am being particularly clear. You show production in your Conventional business falling in FY18 versus FY17, based on a pricing scenario. What is that pricing scenario?

STEVE PASTOR: First, I would say it is not based on a pricing scenario. It is based on natural field decline, and it is very insensitive to the pricing scenario. The second thing I would say is that I do not know that we have been very specific about our own internal pricing scenario.

MILES ALLSOP, UBS: When thinking about forecasting prices, I do not think any of us have been particularly good over the last five years. In the production charts, you are showing a big step up in production from the onshore business, which I presume to some extent is price dependent. How long are you prepared to be patient? What signposts are you looking for to give you the confidence to start stepping up the number of rigs, stepping up the number of wells, and delivering on this production profile? Is it OPEC, or what do you need to see to get confidence in the pricing dynamic? Also, on the exploration side, the timing of production from exploration almost falls off the end of the chart. It sounds like there is very little flexibility in terms of bringing that forward. What can we see to give us confidence in the value upside potential from exploration? Could you give us a sense of the timetable with the drilling programme? Would you be prepared to start farming out some more of the acreage, say, in Trinidad to bring forward some of the value, potentially?

STEVE PASTOR: Two questions there. The first is related to the investability and what signals are we looking at to ultimately determine whether or not we want to go harder and faster with our shale investments, beyond price. Price is one, and I talked about how we are going about through robust signpost analysis, and really keeping a very current and informed view as to where the market is going. OPEC is clearly a big part of that. There are lots of other signposts we look at to give us a view on oil. US rig count, US production, direction and pace of move in inventory levels. A whole host of things in oil, and again a suite of signposts that we rigorously analyse on the gas side. It is more than that. Take, for example, in Eagle Ford. Our decision to increase our activity level there will be a function of the outcomes from our fracking trials that are ongoing there, the staggered lateral work we are doing in the lower Eagle Ford, the upper Eagle Ford trials I alluded to a little bit earlier, and on which Alex will be a bit more specific later, on balance, we do not expect to move more quickly back into the Blackhawk as a function of price, as much as we do a function of outcome from the trial work we are currently doing. That is in part because, as you rightfully acknowledge, without opening up additional investable inventory through the means I just described, Blackhawk has relatively less running room that we do in the Permian. Permian is clearly a lot more flexible. We have actually done a really great job leading the industry, arguably – Alex will make the case a little bit later on – and really identifying the Upper Wolfcamp as the primary most economic horizon there, and figuring out how to drill and complete that in a way that performs better in terms of rate and recovery than the competition. We will show you a graph of our wells initial performance over 120 days cumulative versus the competition. We are in a good spot there, and I would say our ability to flex into that more quickly, because we have a lot more running room, is greater than we would be inclined to flex into in the Eagle Ford, if that makes sense. Gas, in the Haynesville, we understand and we know where the core is, and we have tremendous potential to flex into that more quickly. The two areas where we have the greatest potential to flex much more quickly into will be the core of the Permian and the core of the Haynesville.

Now, to your question about conventional, it was around the ability to bring that programme forward. We challenge ourselves on a regular basis about opportunities to bring that programme forward, and we are doing some extraordinary things. We will talk about how we go about that and the cycle time improvements relative to average industry cycle times from starting an exploration programme to drilling the first well, through appraisal and through development. We will talk about how we do that, and what our outcomes have been and what our expectations are going forward. That is one way. The other is those exploration regions that are infrastructure-advantaged, like the Shenzi North, Caicos Wildling area, and Niall will show you another prospective basin that is nearby the Shenzi North mini-basin. Those are infrastructure-advantaged, and so our opportunity is to bring that on much more quickly, either through existing production facilities where we have knowledge that we can utilise, and even if not, even if they warrant their own new production facility there, they are advantaged by having export infrastructure already in place. We can flex those a lot more quickly. The game there for us is to appraise more quickly, so we can get to a declaration of commerciality and move that forward.

TYLER BRODA, RBC CAPITAL MARKETS: Looking at the slide on page 15, with the exciting outlook for the petroleum business, you mentioned how you are working towards rebalancing away from gas, but when I look at the 2020 to 2025 period, it looks like onshore US gas has become a bigger part of your total production base as well, with the hedging and theoretically the lower returns on the cost curve, it is likely going to dilute some of the return potential. In terms of a transaction, if you are going to do something to rebalance that portfolio, are you looking more towards the conventional side or more towards expanding on the US onshore in the oil side?

STEVE PASTOR: Well spotted, and what you just described is what underpins why we want to rebalance the portfolio away from gas, more towards oil. That, coupled with the fundamentals and the steeper cost, is absolutely right. How we go about that is a function of value creation potential. You already see this exercise in several approaches in that direction: farming down Scarborough, looking to market some of the longer-dated gas options we have US onshore, focusing the very extensive and exciting exploration portfolio that we have on tier one oil and big basins that are material and can rejuvenate and replace the existing remaining resource that we have in conventional. Niall will show you a volume chart on that, but that is how we are going about it in the short-run. Are we also considering trades and M&A to help us accelerate some of that? You bet. We absolutely look at that, but it has got to meet the criteria that I described before, and it is not exclusively focused on deepwater conventional. If we see a fantastic, value-creative proposition in the right spot in onshore oil shale, we would not ignore that.

GLYN LAWCOCK, UBS: I just wanted to follow on, firstly, from my colleague's question. You have talked a little bit about having fracking trials to conduct and lateral works to undertake. When you look at your investable inventory, is that on a risked or unrisked basis? If some of these trials and work that you are doing does not come off, how does that risked versus unrisked impact the chart on page 12, in terms of the inventory? In the second way, this is more a philosophical one, I have listened to you tell me the oil price is going to go higher, yet you are telling me you can produce oil economically at less than 50 from your onshore. You said deepwater development is economic at $50 a barrel. I assume your peers are in a similar position to you; the technology is shared across. Everyone uses the same drilling contractors, etc, like Schlumberger. Why, then, is the price going to go up when you are telling me that almost everything you want to do is economic at $50? In 12 months' time, if the price is wrong, we are sitting here with oil still in the ground, not having gone anywhere, and we have missed out on opportunities to make returns for shareholders. I am just trying to balance your discussion points.

STEVE PASTOR: Let me address both parts of your question. The first is about the investable inventory, and how much of what we showed on slide 12 requires success from our trials. Alex has a chart coming up later in the presentation, and which you may already have showing with and without trial success. To the other question, I will just reaffirm that the supply opportunity is very large, and we do think that US onshore shale does play that marginal cost barrel role, in the mid-run. Beyond the mid-run, and beyond that point in time where the core parts of the best oil shale plays have been developed out, that is a finite resource. We do not see that that continues to play that marginal cost barrel role. Certainly not in the levels we are looking at today. The inducement price required for incremental investment in supply as you move away from the core onto the fringe is going to be higher. Michiel has got a chart that he will show that breaks down what that range of inducement price is for the core and how it compares to the non-core in shale. Clearly they are overlapping, and it is a simplified illustration, but there is a difference and I tell you that all of that goes into our very constructive approach to building up our price forecast.

JAMES GURRY, CREDIT SUISSE: I want to ask, after five years of significant investment, how much running room have you got on capital, and can you moderate the pace of your capital spend in the shale business to ensure free cashflow positive returns, which a couple of months ago and even now are on the horizon? We would be a bit disappointed if that slipped away.

STEVE PASTOR: I will make a couple of comments about that, but also reflect that we are going to talk about that in detail, we are going to show some scenarios reflecting a range of consensus prices, and a range of activity level and investment level that go along with that, and we are going to show a prospective cashflow profile. We are going to show that and go through it in a lot of detail in Alex's section. What I will say about the availability of capital, and maybe that was part of your question, is that one of the true strengths that BHP Billiton Petroleum has from being part of the larger BHP Billiton group is that we have that strength of balance sheet and the fundability of a $100 billion company that we would not have as a pure oil and gas company. It is a true differentiator. Further to that, we have enough liquidity and strength in our balance sheet that nothing that deserves capital is being starved of capital, if that makes sense. There is not a single thing that Alex, or Geraldine, or Niall want to do that make sense for us with our capital allocation model that is not being funded.

JAMES GURRY: If you do not have positive free cashflow, the net operating asset position will continue to build. There appears to be a valuation gap between some of our estimates of what the business unit is worth and perhaps what the carrying book value is. How do you make that assessment?

STEVE PASTOR: In a very detailed way, and across a range of scenarios. Again, I would say let us have a look at some of the scenarios we will describe during Alex's presentation, and what you will see is that it is a tough period. We are at the low point of the price cycle. It is tough to generate positive free cash. We have done that. We are very proud of Alex and his team for having done that, at a pretty low point in the price cycle, and we now have eyes wide open and a much more flexible and agile approach to ensure we can maintain that position. Ultimately, though, you are right. Maintaining neutrality does not get you there. That is part of your question, right, how do you actually generate the value that underlies what we consider as the value of the portfolio, and you have to invest. You have to invest effectively, significantly and at the right time.

I need to stop it there, and we are going to turn over to Michiel, who is going to give you that perspective on our market outlook. Then he is going to turn it over to Michelle, who is going to talk about our financial perspective and she is going to focus on some of the things I've described, focusing on capital allocation and productivity in particular. Then we will open it up for another Q&A. I think we go to break on the back side of that, but there will be lots of opportunities for more Q&A later, and many of the questions you have are quite detailed and I hope and believe they will be answered in the presentations.

3. Marketing

MICHIEL HOVERS, VICE PRESIDENT, PETROLEUM MARKETING: Good morning, ladies and gentlemen. My name is Michiel Hovers and I am the Vice-President Petroleum Marketing. Before we start let me give you a bit of background on myself. I have been with the company for about 13 years, in various roles always in our Marketing organisation. I started with BHP Billiton in energy coal, then moved to uranium marketing, after that I went into nickel and the role before this this job was responsible for our iron ore marketing. My team is based in Perth, Singapore, Tokyo and Houston, where I am based myself as well.

It is my great pleasure to talk to you today about our outlook on the oil and gas markets. In that respect can I also point you to the disclaimer on the slide. It is relevant to my presentation today. I will be covering three topics this morning. First, I'll begin with a view on the crude market. We see the market rebalancing in the near term and remain positive on the longer term outlook. Secondly, I will cover the North American gas markets, where we are positive on the demand outlook, but see abundant supply sources, about which I will talk. Thirdly, I will close off with some considerations around our decision to start hedging in shale gas.

With that I will make a start with our views on the oil markets. Before diving into the short term outlook, let me tell you that in doing all of our analysis, both short and long term, we spend a lot of time on range analysis, as well as different scenarios. We test our plans against these ranges. I will describe to you our mid-case today, but I will also talk to some of the risks we see around this. After 3 years of oversupply, 2017 is finally going to be the first year where we see annual demand larger than the supply. We see demand growing by around 1.2 million barrels next year. On the supply side, however, we see significant excess global stocks, OPEC countries with a strong focus on market share, an inventory of drilled but uncompleted wells in North America as well as a shale industry ready to ramp up and more competitive than ever.

What is the capacity of each of these factors to either bring us back to oversupply or cap any meaningful upside? I will talk to each of these and then share our views on where we think that will leave us for 2017. Let us start with the global stocks situation. Inventory levels are at record high. The oversupply of the last three years created an excess inventory around 800 to 900 million barrels. However, if we look a bit deeper into these numbers we see that around 350 million of these barrels have gone into the strategic reserves of China and are not expected to return to the market any time soon. I should also note that the China is nowhere near done with building their strategic reserves, so this will be a factor for the coming years as well. If we also look at the increased requirement for inventory needed throughout the supply chain due the higher global daily demand, we estimate that the excess commercial inventory is only equal to about two to three days of demand coverage. To put this in perspective, we were tracking around 58 days of global demand coverage before this stock build in OECD countries, so two to three days of excess coverage is manageable in our opinion. We expect that the stocks will be gradually be drawn down and we plan for around 0.5 million barrels of stock draw in 2017.

Now let us move on to OPEC. We forecast OPEC production to stay relatively flat year on year at around 32.5 million barrels per day, while we see growth in Iran being offset by declines in Venezuela as well as Angola. The OPEC strategy is obviously a key uncertainty, especially in light of last week's agreement to agree a production freeze or cut in the upcoming OPEC meeting in November. We monitor this very closely. Outside the US, we expect non-OPEC production to be relatively flat year on year. We see growing outputs from Canada and Brazil will be offset by small declines elsewhere.

That brings me to the US. The first point to note here is that base production is declining significantly. From the April 2015 peak, US production is now down by approximately 1 million barrels per day. If we look at 2017, this base decline of current on-stream wells is set to continue in the order of 1.4 million barrels per day, as depicted by the blue wedge on the slide here. A significant volume of new supply is required just to halt this decline. The first cab off the rank in this respect is the drilled but uncompleted wells, the so called DUCs. The total excess inventory of DUCs is estimated to be around 2,000. We assume around 800 to 900 of these will come online during 2017, which will add about 0.4 million barrels per day of supply. So we do not expect the volumes from DUCs to halt the decline. The remaining gap of 1 million barrels per day will have to come from yet to be drilled wells. On top of this, we actually need to see the US returning to a moderate growth, year on year, to balance the market. For this to happen we need to see an increase in rig count. How the US ramp up will actually unfold is obviously a key uncertainty, and in this regard we can look at history. If we look back to 2011, which was the height of the shale boom, the US was able to add 400 rigs year on year. That was the all-time record. We do not expect this to repeat. We actually anticipate a slower, more conservative ramp up, and early signposts are supporting this view, as rig count is up from the lows and is starting gradually to increase. We estimate the rig count to rise to around 600 by the end of 2017. That is enough to balance the market. I should note that our rig count forecast does account for the significant productivity improvements as well as the increased focus on the core areas of production. We expect most rigs to go into the Permian as well as the Eagle Ford. There is clearly a high a level of uncertainty around this rig forecast. We have price signals, fracking capacity, potential infrastructure, as well as financing constraints, that could all influence the profile of this ramp up.

Summarising on the short term, we expect for next year, continued high production from OPEC, with limited spare capacity, the beginning of the global stock draws, a strong reduction in the DUC inventory as well as a US shale industry that needs to see a turn around to stop the decline. I should note that most of these factors point to a lowering of the safety buffers for the market. This coupled with potential for significant supply wildcards around the current production disruptions in for example Libya and Nigeria, brings us to expect price volatility as well as modestly higher prices for 2017, as a reflection of the tightening of the markets as well as required to stimulate the US shale turn around.

With that, let me now turn to our long term outlook, and I will talk to the demand side first. We expect oil demand to grow by approximately one million barrels per day, per year, over the next decade. That is driven by economic development and a growing urban population in non-OECD countries. Our mid-case is, in this respect relatively green, as it takes into account significant demand reductions due to efficiency gains in the years to come. As a result, we actually see demand from OECD countries declining. Growth from the developing nations, on the other hand, will more than offset this decline. If we look at some of these countries in more detail we see that India this year will overtake Japan as the third largest consumer of oil and is expected to double its consumption in the next two decades from the current four million barrels per day. In India, the transport sector is growing fast. Car sales are already at approximately a quarter of US levels and India's motorcycle fleet is growing at 1.5 million vehicles per month. Turning to China, China continues to be a major contributor. We see a shift here, from heavy industry demand to a more solid consumer-driven demand lead by transport and plastics. With an average of two million vehicles sold per month in China, it has already surpassed the US and will continue to grow. We expect China to overtake Europe around the turn of the decade in terms of liquids demand.

Outside of China and India, in other non-OECD regions such as south east Asia, the Middle East and Africa, this will rise substantially. It will actually account for more than half of demand growth by 2035. Overall, we expect the long-term demand growth to be slower than we have seen in the previous decades, this is partially due to technological progress and energy efficiency. A key area of interest is the electrification of the vehicle fleet. This trend is important to us not only for out oil demand forecasting, but also our outlook for metal as well as steel. In this regard, I would like to highlight our recently launched blog, called Prospects, that is available through our website, where we have started publishing in-house research and views on a wide range of topics. To give you a flavor, I will show you a short video now from our post on electric vehicles. It will take a minute to play.

[*Video played*]

If you want to learn more on our view of electric vehicles, our views on this or other market insights, have a look at the website. You will also find articles on lighter topics, such as the Chinese national debt situation, as well as the peak steel.

While electric vehicles undeniably get most of the media attention, the greatest impact on oil demand will actually be the rising fuel efficiency of internal combustion engines. We forecast that the average light vehicle will become 45% more energy efficient in the next 20 years. This will displace 12 million barrels of daily oil demand over that time period. However if we take all this into account we do not forecast a peak in demand in the foreseeable future.

With that, let me turn to our long term supply outlook. Due to the natural field decline of around 3 to 4% per year as well as the projected demand forecast growth of 1% per year, there is a significant requirement for new supply to be induced. This steep decline rate is significantly higher compared to any of our other mineral commodities. By 2025, the world will consume more than 105 million barrels of oil on a daily basis, approximately 30 million of which will have to come from new, to be induced, supply. To put this in perspective, this is equal to one third of the current global demand, and is only nine years from now.

Despite this significant supply challenge, we have seen hundreds of billions dollars in cuts in upstream spending during this downturn. So, where is this supply going to come from? To answer this I out the chart on the slide. I will talk you through it. The chart shows a schematic of potential sources of new supply by 2025. Here you see indicative volumes per supply source, designated by the width of the coloured wedge, as well as an indicative range of cost of supply, designated by the height of the wedge. The first point to note here is that many different sources are required. Secondly, many of these sectors have a core that is profitable below $60 per barrel, i.e. the lower part of many of these wedges. Shale is no exception. Not all shale is created equal, is an important point. Core areas of shale are competitive, but non-core areas require significantly higher prices. To better illustrate this I have split shale into core area and non-core area, which you can see on the slide. We expect the core of the shale to be fully developed.

Over the next decade, the shale growth is primarily coming from the Permian as well as the Eagle Ford Plays. The Permian basin benefits from its large areal extent and multiple stacked plays. The Bakken play is also expected to resume growth but to a lesser extent given its maturity and higher costs per barrel. Plays such as stack and scoop in Oklahoma are low cost, but they are much smaller and will contribute less to the overall supply base.

Low cost shale is, in our view, finite. On top of this almost 50% of core areas will have to be developed just to offset the base decline. Shale will be an important and growing supply source for the world; however it is by far not big enough to capture all the supply growth needed to meet the gap. Conventional oil fields as well as deep sea developments will be required to meet the demand. We should note that many of the conventional supply sources are in countries with significant above ground risks and high barriers to entry. This increases the likelihood of disruptions and delays, at a time with limited OPEC spare capacity.

To conclude the long term supply outlook, in the recent downturn the industry has focused on sweet spot development and achieved remarkable cost savings. The industry will continue to focus on productivity; however, it is important to understand that geology is and will remain a limiting factor. Therefore we see a reasonably steep cost curve beyond the mid-run.

This concludes my remarks on the oil market outlook. I will turn to the second topic, the US gas market.

Last year's mild winter and resulting high inventories drove market prices to 17-year lows earlier this year. However, we had healthy summer demand and a production decline that led to a normalisation of the inventories. We have witnessed, as a result, significantly higher gas prices to a level more in line with inducement costs, as you can see on the graph at the bottom of the slide. This is needed, as supply is declining, but will have to grow by 5 BCF per day in 2017, to balance the market.

Let me turn to our long term outlook on gas. Our demand outlook for gas is very positive. We see the total North American gas demand grow by about 30 BCF per day to around 120 BCF in 2025. That is a 3% annual growth. The good thing is that the demand growth is diversified and is underpinned by multiple sectors. First of all, the power sector. Natural gas is now the largest fuel source in the US. Use of gas in power generation increased from 24% in 2010 to 34% today. The overall gas demand in the power sector is expected to grow at around 2% annually in the coming decades.

The industrial sector is also showing healthy growth, fuelled by the expansion of the petrochemical industry, adding roughly 8 BCF per day by 2025. On top of this we see increasing exports to Mexico as well as the US LNG exports having just started, and are expected to grow to almost 10 BCF per day by 2025. This will turn the US from a net importer to a net exporter of gas. Our assets in and around Texas are ideally located to capture these markets. We are near the expanding Petrochemical industry, Mexico is obviously close, and we are in close proximity to the main LNG export terminals in the gulf. This gives us a significant transport advantage over the gas produced in the Marcellus and Utica in the North East of the US. Talking about Marcellus and Utica, it is fair to say that there are abundant supply sources for gas. Marcellus and Utica combined will represent 40% of North America supply by 2025. That is close to doubling in size in 10 years.

Elsewhere, we will see more associated gas from the Permian and Eagle Ford, as well as increased production from the core of the Haynesville, so all add to the supply base. Recent industry productivity improvements and identification of the core plays have flattened the cost curve and will limit any significant price appreciation in the short term. We do expect price volatility to continue as seasonal demand, weather and storage levels will continue to drive prices in response. In the long run, steep decline rates and the depletion of the cores will drive the need for mid and higher cost resources to be developed, bringing prices to sustained higher level than the current market price of around $3 per MMbtu.

With that, let me now turn to my last topic: hedging. I will focus on the rationale for hedging and our approach, and Alex will in his section touch on the subject as well. As was remarked earlier, at BHP Billiton we have a longstanding floating price philosophy, and this is suited to a portfolio of long life, low costs assets. Our typical assets experience various price cycles throughout their long life and they secure an acceptable return in the up and down part of the cycle, as long as the position on the cost curve is excellent. Now, the shale business differs from our typical mining or conventional assets in the fact that around 50% of a shale well’s production occurs in the first three years. As illustrated on the chart on the left, the decline rates in shale are steep. This is a very different production profile than, for example, an iron ore mine, where we would see a steady production profile for many, many years or even decades. But a relatively short lived high production period in shale could coincide with a lower part of the price cycle, and this can compromise returns.

It is this effect, coupled with the unique dynamics of the US gas market, that I will describe now, that brought us to consider a different approach to pricing. The US gas cost curve is relatively flat. There is also a tendency for a large portion of the shale gas producers to hedge. As a result a pattern is created, whereby a price spike, due to a cold winter for example, can lift the forward curve and create a hedging opportunity that induces a material volume of new production, because of that flat cost curve. This can then lead to an oversupply of gas. This oversupply results in low prices in the spot market that can linger on for an extended period of time. The hedged producers are insensitive to this. Unhedged producers are exposed to these low spot prices. For this reason, we decided to deviate from our normal floating price philosophy and have started hedging for shale gas. The core idea here, and this is very important, is that we do not take a view on price, but we take a view on a rate of return. We do this by, not only locking in the forward gas price, for the first couple of years of production, but also the input costs, i.e. we fix the costs for drilling, as well as the completion costs and many of our other supply rates, thereby locking in a narrow range around a rate of return. In other words, we are de-risking our capital allocation decision. To lock in excellent rates of returns is, of course, only possible by the great work on the cost saving side. Alex will in his presentation talk to this as well the expected outcomes of our initial hedges, and growth plans for our gas production.

So the obvious question is, which Steve alluded to earlier, should this apply this to shale oil as well. In the current environment we do not see the need to extend hedging to oil. The market dynamics are different. We see more upsides than downsides in the oil price. Another important consideration in this regard is that in our low price scenario for oil, our shale investments still make an acceptable rate of return. Therefore we choose to retain the upside risk, and can live with the downside risk in shale oil. Having hedging as a tool allows us to be more dynamic and agile with our capital allocation decisions. In other words, when the time is right, we can react quickly to secure a rate of return that brings forward the resource monetisation with higher confidence. Michelle will next talk about the capital allocation strategy in more detail.

This brings me to the end of my presentation. Let me conclude with some summarising remarks. We do see the global oil market rebalancing in the near term. Our long term outlook remains very positive. On the North American gas side we see strong demand growth; however, abundance of supply is likely to limit any significant price appreciation in the near term. Finally, we believe that hedging will help us accelerate our gas developments at good rate of returns.

4. Finance

MICHELLE TURNER, VICE PRESIDENT, FINANCE PETROLEUM: I am Michelle Turner, Vice President of Finance for Petroleum, and I am really excited to be here today. I joined BHP Billiton in April, about six months ago, having previously worked at two global manufacturing companies. Today I sit on the Finance Leadership team reporting directly to BHP Billiton's CFO, Peter Beaven. I am also a member of the Petroleum Leadership Team and collaborate closely with Steve and our team in Houston. While Steve and his team focus on safety, volume and costs, my team executes the financial strategies, really focused on creating and accelerating value. Our priorities are two-fold, one, around continuous improvement environment, one that really drives the cost mentality down to the individual decision maker. The second is really around driving a commercial mindset. Think of this as driving business acumen. How do we deliver returns? How do we incentivise and create an environment where employees are thinking about creating returns for our shareholders?

My finance team partners with the operations to proactively drive to meet our financial commitments. I, along with my peers in the mineral businesses, do this using a consistent and disciplined approach that we apply globally across all of our operations. My team physically is located with our Petroleum assets in Houston and we work seamlessly with the group to drive overall BHP Billiton's financial performance.

We just heard the market perspective from Michiel, how the supply/demand rebalancing is presenting a positive outlook for our portfolio and the expectations around increased supply opportunities for the commodities we play in. Now, I am going to shift the lens to share our view from an internal perspective, and how the actions we have taken, and will continue to take, position us well to deliver sustainable returns into the future. This, coupled with our investment through our disciplined capital allocation framework, is positioning our Petroleum business to be one of the key pillars of BHP Billiton into the future.

Before I start, let me point you to the disclaimer and take a minute to read through this. It is important we remember this. We are going to be sharing a lot of great data with you today, so if you can keep the disclaimer in context, we would appreciate it.

In my presentation, I will cover three themes. First, the petroleum business track record and how it contributes to BHP Billiton's overall financial performance. Second, our relentless focus on productivity, both from an operational cost perspective and capital efficiency, and how we are doing more with less. Thirdly, I will also explain how the investments in Petroleum's projects fits into the overall group capital allocation framework.

Earlier, Steve addressed how Petroleum is key to BHP Billiton, how it complements the diverse commodity portfolio, it allows capital mobility across the commodity cycles and how it supports strong EBITDA margins within BHP Billiton's portfolio. Petroleum has consistently delivered strong results over many years. We delivered $3.6 billion in EBITDA in FY16, in a low price environment. Assuming the mid case consensus prices, the business will generate EBITDA close to $8 billion over the next two years. Complementary to our contribution to the company level results, we also regularly benchmark our performance against our peers, and we are proud to continue to deliver best-in-class results. You can see on the chart, we delivered on average 66% EBITDA margins over the last five years, in comparison to 50% against our peers. This is 5% above the next top performer, which is evidence of our value over volume approach we have been talking about throughout the presentations today.

We are particularly proud of the result of our focus on productivity, with our unit cash costs down 30% in the last two years. Even though we are expecting slight volume decline in the coming years, we expect our unit costs to remain around $11 dollars a barrel over the next two years, even if oil prices rebound.

Before I explain more about our strong results in productivity, I want to take a moment to comment on Petroleum's depreciation rate, as it is one of the more difficult parts of our business to model. Our depreciation rate in FY16 was approximately $17 per barrel and is expected to increase slightly to $18 in the coming year. It is really driven by a couple of things. One, the completion of the Longford gas conditioning plant increases our depreciation rate slightly in our Conventional business. Two, looking at our onshore business, the FY16 unit rate did decline following the impairments we took last year, though this was offset by price-related impacts as we move into FY17. You should expect to see our onshore rate increase by about 4% year over year. It is worth noting given the flexibility of our onshore business that we are poised to react to improving commodity markets. Accelerating our field developments at a significantly lower cost per well, that we have been consistently been delivering on, will result in lower unit DD&A rates over time.

Moving onto productivity, this is the chart I am most excited to talk about, because you will see some great results here. We have a lot of plans into the future, as well. We have actively responded to the challenging price environment and we continue to refine our operating strategies to maintain agility in the macro environment. There are really four pillars to our productivity focus: one is operational efficiencies; two is around organisational effectiveness, which is the people component of our cost infrastructure; three is around capital efficiencies; and four is around cultural change, the changes we have been on and the change we continue to drive into the future.

First is our operational efficiencies. Our controllable operating costs decreased $677 million in FY16 alone and our unit cash costs per BOE decreased almost $3 over the same period to less than $10 a barrel. In parallel with focused programs on cost take out, we are also aggressively managing our working capital, really driving a greater focus on our operation cashflow, so we have more dollars to invest back in the business.

From an organisational effectiveness perspective, we are taking steps to right size our construct driving additional efficiencies. Since 2015 our G&A expense is down 22% and our overall headcount is down 28%. In addition to reducing our headcount, we have significantly increased our efforts around offshoring, into low cost regions like Kuala Lumpur and Trinidad. In the last two years alone, we have doubled our headcount from an offshoring perspective, and we expect to double it again this financial year with the inclusion of technology to the offshoring model. Our Trinidad resourcing strategies are particularly unique, in that they offer an opportunity not only to lower our costs, but to aid the local economies where we do business. It is a win-win, organisationally and with the communities that we play in. Finally, the simplified operating model offers best practice sharing across the organisation, as Steve commented, but it also delivers a more efficient cost infrastructure and greater agility through organisational delayering and streamlining decision making so we can make decisions quickly that allow us to impact the business in real time.

Moving on to capital efficiency, we are working with the breadth of our supply chain to drive additional savings. In FY16 alone, we delivered roughly $300 million in supply savings driven across a multitude of initiatives, including price renegotiations, and a real focus around supplier rationalisation, driving to fewer suppliers so we have greater leverage in the price negotiations with them. We did see our supply base come down by about 10% in the last year alone. From a capital efficiency perspective we have seen significant improvements over the last two years including benefits from technology, redesign improvements and cycle time reductions. We are seeing this across the board in onshore and Conventional. Alex will share later the specifics in regards to what he and his team are doing around our drilling cost savings, and Geraldine will share similar results on our major project execution.

Finally, on the culture, we initiated a transformation campaign in 2015, focused on driving a cost mentality down to individual employee level. This is a grassroots approach; how do we get our people engaged on an individual level. Since beginning the program, we have had over 3,600 ideas submitted with a third of these ideas having already been executed. Additionally as part of our simplified operating model, we are changing how we do business. We are increasing the capabilities of the finance business partners to challenge organisationally how we think about a continuous improvement, and how we make it part of our daily remit and increase our business acumen and our commerciality mindset to show that the decisions we are making day in and day out drive returns back to our shareholders. Having been here six or seven months, I can tell you that the global Finance function is focused on every aspect of productivity, really leaving no stone unturned. We continue to get asked if all the low-hanging fruit is gone and whether productivity is done and the train stopped. From my 21 years in the manufacturing industry, the answer is no. There is no reason that we should not be targeting cost reductions year over year.

Moving on to our capital allocation process, under the simplified operating model, the strategy and capital allocation processes have been centralised under Finance. This structure ensures discipline and consistency across the company in how we allocate capital. The framework is focused on strengthening our balance sheet and maximising our returns to our shareholders. One of the key elements of this framework is that our petroleum capital projects compete for capital against minerals projects for capital. With the framework focused on maximising value, our petroleum business is really well positioned to compete for future capital, given the high internal rates of return across our business are generated; whether it is onshore, convention or exploration, we see really high RRRs in our projects, which allows us to compete well against the minerals business.

Moving on to our capital spend. Over the past three years we have seen our investment in conventional projects decline, as we completed several major projects, but also because of the capital efficiency that I talked about earlier, our ability to do more with less is allowing us to drive less in our capital spend in conventional. I should note that with a large suite of high return brownfield projects averaging returns of 45%, and with the potential Board approval of Mad Dog Phase 2 you could expect capital spend to increase in the years ahead. For onshore operations, we actively responded to market conditions and our capital spend has reflected the recent reduction in activity levels. In order to remain flexible and capitalise on changes in market conditions, senior leaders including Alex, Steve, Michiel and myself, along with our CFO and President Marketing and Supply, assess our investment plans regularly and allow for a dynamic change in our allocation of capital into our onshore business.. If market conditions improve as we expect them to, you could expect that capital investment will increase in the years ahead, and Alex will provide you with some scenarios on potential investment later today. Finally, our exploration programme offers an exciting opportunity to organically grow our Petroleum business with lower costs for discovery and development. This continues to be a highly competitive way to refill our portfolio in tier one assets. As you will hear from Niall later today, we are very excited about our current portfolio.

To conclude, Petroleum is a key contributor to BHP Billiton with high margins and strong EBITDA performance. With the healthy return projects in conventional and our high quality acreage in shale, we will continue to be a significant contributor to the overall Group financial performance. We have and will continue to focus and deliver on operational efficiencies and capital productivity. Finally, our capital allocation framework provides improved discipline across the company. With high return projects, both in onshore and conventional, the Petroleum business is well placed to compete for capital and remains flexible so that investment can be matched with market conditions.

STEVE PASTOR: You can all see, from Michiel's presentation and Michelle's, just why we are so excited and why I am so proud of what we have in front of us as BHP Billiton, and the strength and depth of our leadership team, and the connectedness we have that leverages the functional expertise across the globe. It is extraordinary, and I know you are going to see and feel more of that later on when you hear from Alex, Geraldine and Niall. Now it is time for our break. We will start back promptly at 10:15.

[*Break*]

5. Onshore US

ALEX ARCHILA, ASSET PRESIDENT, SHALE, BHP BILLITON: Good morning to all of you. Thanks so much again for joining us this morning, both here in London and via the webcast. My name is Alex Archila. I am the Asset President for our US shale assets. I have been with BHP Billiton for about seven years and in this position for about a year and a half. Before joining BHP Billiton, I was with Chevron/Texaco for about 22 years. As I was telling some of your colleagues this morning, I am very excited to be here today and to have the opportunity to talk to you about how we have been turning around the operation recently and, more specifically, about our plans to capture the full value of the asset while driving returns and, at the same time, accelerating free cash flow. Before I go into that, let me point you to the disclaimers that are important to my presentation. There is then a second disclaimer that deals with our Petroleum oil-and-gas resources.

There are three overarching messages that I would like to leave with you this morning. The first message is that our Onshore US assets are both very high-quality and very large. We are going to share with you our updated resource analysis which results in up to about 1,400 net future wells that could deliver returns of over 15% at $50 per barrel and $3 per MMbtu, and roughly another 1,500 net wells at higher prices within the consensus range.

Second, we are going to show you some compelling data that will illustrate how far we have come as an operator in these assets. As part of that, we are going to share with you third-party technical benchmark data that will show you how our latest wells at the Permian and the Eagle Ford are beating the competition. We are also going to cover with you how our efforts as well as our recently implemented gas-hedging programme that you just heard about are increasing the number of economic locations, as I mentioned earlier.

The third message that I would like to leave with you today is that we are going to show you a set of three scenarios of activity and their resulting net cash flow under different prices to illustrate to you our flexibility in delivering strong returns and positive free cash flow starting this calendar year.

These goals will be complemented by the monetisation for value of non-core acreage, of which we have completed roughly $100 million already this fiscal year. Maybe the best way to summarise my message for you today is that, at the consensus prices that some of you have given us, our Onshore US Shale business is very well-positioned to become a material business with significant flexibility to adjust to changing market conditions.

Let us first start with a quick recap of our existing operations using the map on the right as a reference point. The portfolio, as you probably know, includes a mix of liquids-rich and dry gas fields across the states of Texas, Louisiana and Arkansas.

Eagle Ford is currently our largest producing area and is made up of two distinct fields: the Black Hawk and the Hawkville. Black Hawk represents some of the most prolific acreage in all of North American Shale, given its high-deliverability condensate wells.

Hawkville is a bit more variable as it is comprised of liquids-rich acreage in the north and a gassier part in the south.

As many of you know, Permian is a multi-horizon, liquids-rich basin, located in West Texas. I am very excited to talk with you today about the Permian. You may not know this, but at the time of the Petrohawk acquisition, we acquired and valued Permian as pure exploration acreage.

Finally, Haynesville and Fayetteville are both dry gas fields located in Louisiana and Arkansas respectively. We recently restarted drilling at Haynesville with one rig, and we supported this by our gas-price-hedging programme to narrow the uncertainty of returns, which we are now expecting to be upward of 30% and, as you will hear about, we have plans to expand our programme substantially in the near term.

This slide helps us set the general context of where we have been from a production and capex perspective, but it also illustrates that the Onshore US Shale business provides flexibility to respond quickly to market conditions. In the period of high prices, we were able to grow production at a compounded annual growth rate of about 14% over a period of three years. We were also faster to react than most competitors in reducing investment when prices started declining, taking capital down by 70% between FY15 and FY16, and we are now planning to take it down by a further 50% this fiscal year. When you combine all that, it represents approximately an 85% capital reduction over two fiscal years.

Our productivity efforts have helped to partially offset the pace of production decline that results from reduced investment. Relative to the 85% reduction in capital from FY15 to FY17 that I just mentioned, we expect production to decline by roughly 35% over the same timeframe. This disproportionate change is partially attributable to increasing capital efficiency and improved well performance, both delivered safely through productivity. As you know – and you have heard this at BHP Billiton before – productivity is integral to our plans to deliver strong returns from new investments while also accelerating positive cash flow.

As we start talking about the future and new investment, let me begin with reserves. We have access to 3 billion barrels of proved and probable reserves in oil-equivalent terms, including about 500 million barrels of oil. These 500 million barrels of oil are equivalent in size to the exploration programme that we are chasing in the conventional world. Our current plans envisage development of approximately 3.5 billion barrels of oil-equivalent resource, including a small portion of contingent resources. These plans are, of course, based on our internal view of long-term oil and gas prices and our view of costs. There remains a significant long-term opportunity to employ productivity and new technology to bring more of those contingent resources into our development plans as time goes by.

Finally, the largest portion of our portfolio comes from gas, and we are actively pursuing opportunities to monetise these resources through accelerated development of the core acreage, supported by the hedging programme, along with the potential divestment of non-core gas acreage for value, as Steve mentioned to you earlier this morning.

I also mentioned earlier the progress that we have made in productivity. I am going to start with drilling and completion costs and then move to operating costs and well performance. Total costs over time for Black Hawk and for Permian are down approximately 40% in the past two years, with a very large component of these savings attributable to structural efficiency gains that will remain, even when the price cycle turns again. I am speaking specifically about things like casing-design optimisation, faster drilling and faster completion-execution rates. These productivity gains have directly and significantly improved the investability of our portfolio by lowering break-evens across the board. I am going to take you through that in just one moment.

We have also had great success bringing down our operating costs. As you are aware, the decline in iron-ore and copper prices started a couple of years before the decline in oil and gas prices came. As a result, we, at Petroleum, were fortunate enough to be able to take advantage of the tools and processes that have been used with great success in our minerals businesses.

Also as important, we are driving, as Michelle mentioned to you, a continuous improvement and cost-awareness programme. I travel to the field every month and, whether I am talking to a well pumper, a production engineer or a manager, my personal emphasis on safety, productivity and value creation, as opposed to volume growth, has been constantly there since I took this role last June. What I am suggesting to you, then, is that what we are also delivering is a cultural change.

In terms of our monthly expenditure in absolute dollars through FY16 as compared to the FY15 average, there was a very clear downward trend throughout the year and, in fact, we ended FY16 with our costs down about 30% relative to FY15. Every single field has delivered material reductions in operating costs per BOE, even as, in most cases, production declined year on year, so the denominator was against us. These are material savings, ranging from about 20% to as high as 44% in the case of Haynesville. Permian's current higher opex relative to Eagle Ford is largely due to the fact that we do not yet have centralised process facilities and we are currently trucking water out of our mostly single-well pads. This will change as we move into the development of Permian, as I will show you later.

In addition to these savings, G&A costs were reduced almost 20% relative to FY15, following the right-sizing of the organisation that we undertook earlier this calendar year. However, I do want to stress to you that we have maintained the organisational capability to ramp up in the short term. We expect further G&A savings as we take the Global Simplified Operating Model and implement it across BHP Billiton.

Finally, in the area of productivity, we are also actively improving the performance of our wells, such that we extract more resource and more barrels for every dollar that we spend. As you are probably aware, we were earlier to the Eagle Ford and the Delaware part of the Permian than most competitors. This early-mover advantage has allowed us to stay ahead of competitors in terms of well deliverability. IHS data normalised for lateral well length and proximity show that we are delivering very well relative to competitors in terms of performance and optimised completion and design. As with well costs and operating costs, these gains directly improve the investability of our drillable inventory and expand the overall size of our future development programme by lowering investment break-evens.

In a moment, I am going to show you our updated investable inventory incorporating the savings and well-performance improvements that I just described to you, and after that I will also show you a range of investment scenarios going forward. Before getting into that, let me provide a quick snapshot of each of our fields, starting with Black Hawk.

Although our core area for the Lower Eagle Ford horizon is largely drilled, we continue to see running room in the field, particularly in light of the productivity gains that we have been achieving. There is significant undeveloped Lower Eagle Ford acreage in the condensate-rich areas of the Southwest, Main and Northeast sectors that could be highly attractive, depending on the results of ongoing trials that we are conducting, and I will explain those a little more. The trials are testing several things, including the potential for staggered wells to increase recovery, confirmation of early results that we got that tell us that larger frac jobs can significantly improve productivity, and the potential of the Upper Eagle Ford horizon, which has been confirmed by other nearby operators and remains undeveloped in a large section of the field. We expect the outcome of these trials to be known in about the third quarter of next calendar year. We currently have just one rig drilling in the field and, if the outcome of our trials is positive, we are anticipating that we could pick up another rig sometime next fiscal year.

Also, as you may recall, we stopped fracking in February of this calendar year after prices hit $35 per barrel. You may remember that, in the guidance that we provided to you at the time, we indicated that we would come back to work when the price hit $40 per barrel. You know where prices are today and we are now back working with our trials and the rest of our inventory of drilled uncompleted wells, otherwise known as DUCs. We currently have four spreads working in the Eagle Ford, increasing to five later this month. We plan to have roughly 45 new net wells online this fiscal year, which will complement our production in the second half of the year, partially offsetting the field decline.

In the other part of Eagle Ford – the Hawkville – we also see upside potential from completion trials and continued productivity gains. Recent trials that we have conducted, along with trials completed by other nearby operators in which we have equity interest, show that well performance can be significantly improved through completion optimisation. This could add approximately 230 net wells. The graph at the bottom shows you the performance of these trials relative to completions that we used to have prior to the completion-optimisation design changes.

Before getting back to drilling, we intend to finalise our trial programme over the next 18 months, which aligns very well with the upcoming acreage-retention drilling obligations that we have in the field. Our acreage position in Hawkville is very large and the near-term holding cost is minimal. That said, we are evaluating the potential divestment or alternative monetisation of some of our dryer gas acreage to accelerate value by more quickly turning NPV into cash that we can potentially invest into our core areas or elsewhere in the BHP Billiton portfolio.

The Permian field is very close to my heart, as I used to be the General Manager there shortly after we acquired it from Petrohawk. We are now producing, as Steve mentioned, 30,000 barrels of oil equivalent per day, mainly from the Upper Wolfcamp horizon. As I mentioned at the start, our Permian programme initially began with a fairly large and dispersed position across West Texas, both in the Midland basin to the east and the Delaware basin to the west, and we valued the acquisition as purely exploration acreage when we acquired Petrohawk.

Since my time as General Manager there, we have focused on building a position in and around Reeves County, where we were able to demonstrate prolific Upper Wolfcamp performance ahead of our competitors in 2013. Since that time, we increased our acreage in what we call our development area by 60% for less than $4,000 per acre. I am sure that you are aware that, right now, parts of this area are attracting as high as $35,000 per acre in the marketplace.

We now hold approximately 78,000 net acres in the development area and are focused on acreage-retention drilling with one rig while undertaking additional tests to optimise our development plan. As part of this optimisation, we have been successful in swapping approximately 4,000 net acres with other operators in the area to build contiguous sections that are enabling us to drill longer laterals and, therefore, get higher returns. Another similar swap to that one is underway right now and we expect to complete it soon.

We are now moving towards full pad development within roughly a couple of years. We are taking a very deliberate approach to development to ensure that we maximise value and deliver predictable returns. I can tell you that we now have a clear line of sight to a 150,000-barrel-equivalent-per-day business in net terms, based on a six-rig programme, targeting the sequential development of the Upper, Middle and Lower Wolfcamp horizons. Additionally, we are actively evaluating alternatives for the midstream gathering system that is required for us to move into pad development, with a view to seeing how we can minimise capital requirements, including a third-party solution.

We are very confident in our ability to turn this into one of the largest production and cash contributors of the BHP Billiton Petroleum portfolio. Just as a comparison, 150,000-barrel-equivalent-per-day net production would be roughly 50% larger than what we are producing from our Bass Strait asset today. If I seem excited about the Permian, it is because I really am. Just as we are proud of our progress in the Permian, we are equally proud of the advancements that we have made in Haynesville, which is where I am going to turn next.

We have just restarted drilling in Haynesville with a one-rig programme that will deliver 16 wells with high confidence in returns that are north of 30% excluding sunk transportation costs. After successful trials in FY15, we are deploying an optimised completion design that we believe will significantly improve well performance. We have also locked in gas prices at around $3 per MMbtu via the hedging programme, and roughly 90% of the supply-contract rates that are required for this activity.

As I just said, in Haynesville a large proportion of our transportation costs are based on fixed-volume commitments of which we only use a small portion. New investments are taking advantage of this excess capacity and helping support the compelling business case for the development of the Haynesville. This is a great example, in my view, of utilising latent capacity through improved well productivity and commercial flexibility.

With new, low-risk, high-return investments, we are confident that the Haynesville can become a significant cash contributor and, to that end, we are assessing, as I said earlier, an expansion of our drilling programme as early as the next fiscal year. In the event that we do that, we can see a path to more than doubling our production from Haynesville and becoming cash-flow-positive within a couple of years.

Having said that, much like Hawkville and as Steve mentioned before, there are elements of our Haynesville acreage position that are less attractive, especially the part that is operated by others. We are, therefore, assessing the potential divestment of this acreage, if we feel that it can be sold for value.

Fayetteville is, of course, our other dry-gas asset and, in this case, we currently have no operated drilling or near-term plans to return to drilling. However, I want you to know that the Fayetteville is currently cash-flow-positive and carries minimal holding cost with the vast majority of our acreage held by production already. We are working with our partners in the field to assess the potential of the Moorefield horizon, which has been tested by other operators with some success. This could provide an avenue in the future to accelerate development, so we are going to continue to monitor market conditions to determine the optimum monetisation path for the Fayetteville, whether that is through a well-timed development of the Moorefield or the Fayetteville horizons, or potential divestment, as we tried to do before.

When you combine the quality of our resources and the productivity gains that we have made over time, as I showed you, this results in a very large inventory of economically attractive options, even at low prices. Our inventory of investment options can deliver a minimum 15% rate of return at various flat price bands. In our liquids-rich fields of Black Hawk, Hawkville and Permian, we have over 1,200 competitive net wells below $50 a barrel, with more than half of those in the Permian. At higher flat prices, hundreds of additional net wells become competitive for investment.

As I said previously, a portion of our liquids-rich inventory is subject to the results of the Eagle Ford trials. While we are absolutely planning for success, we have elected to show you the investable inventory both with and without the success of the trial programme. There is a very large well inventory at Haynesville that we want to get after with the accelerated development programme that I spoke of earlier. Given our large well inventory, we expect to increase investment and shareholder value in the months and years to come, which is exactly what I would like to speak about now by walking you through a number of investment scenarios that we have developed for you this morning.

The range of mid-case consensus prices from a number of investment banks were disclosed in the disclaimer earlier in the presentation. We have taken this range of mid-price assumptions to construct three investment scenarios over the next five years. This is simply a range of price scenarios for illustrative purposes, and none of these prices exactly correspond to BHP Billiton’s view of prices going forward.

These charts illustrate how we might respond to the price scenarios I described in the previous slide. It is important to recognise that the capital investment and rig scenarios presented here are not guidance; they simply represent how we could respond in differing price environments. In reality, as Michelle described, all investment options in our shale business are actively assessed under the group-wide Capital Allocation Framework and are informed by our expectations of market conditions.

The first chart on the left corresponds to the average consensus in which gas and oil prices rise above $3 per MMbtu and $60 per barrel after FY18 respectively. In this case, we would foresee higher activity in Haynesville beginning in FY18, followed by a ramp-up to full development in Permian at six rigs by FY20. The black line in all the charts shows the capital spend that corresponds to that particular scenario.

The chart in the middle corresponds to the high end of the price range. In this case, the level of investment in each of Haynesville, Hawkville and Permian is both accelerated and increased. However, even in this scenario, we would not foresee a total rig count of much more than 20, based on the expected productivity of these rigs and the importance of preserving the level of productivity that we have achieved at this higher level of activity. Capital spend in this scenario peaks at less than $3 billion per annum in nominal terms.

Finally, the chart on the right corresponds to the low end of the price range. In this case, we would focus on acreage-retention obligations while selectively investing in very discretionary wells that deliver attractive returns.

In terms of the range of production that we would expect under the range of rig-activity scenarios that I just described, inclusive of base production, which we expect to decline at approximately 15% per year from FY18 to FY22, even in the low-price and low-investment scenario we would expect to hold total production relatively flat from FY18 onward, while, under the mid and high scenarios, production growth is significant, potentially doubling in the next five years.

Again, I reiterate that this is not guidance but simply a demonstration of how we could exercise the flexibility of our shale portfolio in the future.

Putting together prices, capital investment and production, with regard to the resulting range of pre-tax free cash flow going forward, what is clear here to us is that, under most analysts' mid-price scenarios, and assuming that we match investment to price, BHP Billiton's Onshore US business would be slightly cash-flow-positive for the next two to three years. This investment will then create the opportunity to deliver very significant free cash flow to the Group by the end of this decade. As we ramp up activity, we should expect to be able to fund the investment from shale cash flows.

We see a very attractive future for the Onshore US business, with as high as $3 billion of annual cash flow at the top end of the price within five years, and significant cash-flow outlook for the following decade. Of course, as Steve mentioned before, and I will mention it again, price-forecasting contains an inherent degree of uncertainty and that is why we are planning to a range of outcomes. There is the risk that you plan for high prices and end up in low prices, so, as Steve said earlier this morning, what we are trying to do is mitigate this in a couple of ways. First, we are allocating capital very proactively on at least a quarterly basis and have less fixed obligations with rig contractors. This allows us to invest and move more quickly than in the past. Second, as I have already discussed, we are using hedging to reduce the risk of investing into a cyclical high and then being faced with falling gas prices. Finally, again as I said early, we are pursuing monetisation of non-core acreage, like the $100 million of sales that we have already obtained, which are included in the FY17 numbers.

To summarise my presentation, I hope that you can see that we are taking decisive and specific actions to enhance our Shale portfolio. We took swift action in our capital expenditure when prices moved. We have also taken strong actions to control costs, including painful but necessary rightsizing of our organisation that has not compromised our ability to grow the business in the short term. We are optimising future development by fully appraising our fields prior to large scale investments, thus ensuring that we end up with robust economics. We are also using commercial strategies to provide acceptable returns relative to the risks that we have, including flexible supply contracts, gas hedging and the divestiture of non-core acreage for value. We are also allocating capital to ensure that we nimbly respond. Finally, by carefully assessing our investment inventory, we are positioning ourselves to create material free cash flow with attractive returns for shareholders in the years to come.

This concludes my presentation. Thank you for your attention. Steve is now going to guide us through the Q&A session.

6. Questions and Answers

STEVE PASTOR: I am going to invite Michiel and Michelle to join us on the stage. We did not have a Q&A session after they spoke, so this is an opportunity for you to ask questions about any of those presentations.

SYLVAIN BRUNET, EXANE BNP PARIBAS: I have another question on hedging, just to get a sense of what percentage of your overall volumes are already hedged. You are suggesting a 30% return; presumably, other people are going to follow this strategy as well, which could put your non-hedged part of the portfolio at risk.

STEVE PASTOR: Michiel and Alex are probably best-placed to that; I would just wade into that by saying that it is a relatively small position that we have taken to date. Alex talked about that being, if you will, a trial or a pilot to enable us to understand our ability to do that well and then potentially scale off of it, so I will hand over to Michiel to talk about the volume.

MICHIEL HOVERS: Thank you very much. As Steve said, it is relatively limited at the moment, so we are talking literally about a couple of percent of total gas flowing out of the Shale business. We have many more unhedged molecules at the moment but, as we look to scale that up, you will see that portion increase.

STEVE PASTOR: I think we have been clear that it was about a 75 bcf pilot over three years, so you could look at that relative to our total gas production and see that it is about 2%.

RENE KLEYWEG, DEUTSCHE BANK: With regard to the at-least-15% IRR forecast and the 1,200 wells, could you give us a broad indication of what the average IRR of that portfolio is at $50? Second, you have not drilled in the Haynesville for a while. You are not assuming cost reductions in your $7.5 million-per-well capex intensity. If you benchmark that against what you have seen elsewhere and what you have learned over the last 18 months, what can you expect to get that down to? Is it a sub-5 number, or 5-5.5, or 4.5-5? What kind of ballpark number do you think you can do in terms of costs?

STEVE PASTOR: During the break, I talked about us getting back to work in the Haynesville for the first time in roughly 18 months, so I will go on the record and declare that that $7.5 million is going to be a conservative start and that we are going to see the same sorts of extraordinary productivity improvements that we have seen in the Eagle Ford and in the Permian, and we will be able to beat that going forward. That may be a challenge to the rest of the team.

In terms of the range of economic returns on individual wells that are placed in that $50 flat price band, it is going to be a range. There are some that are very high and some that are just making that 15%. Remember that, to create that chart, that is flat real. Generally, when we consider the economic investability of our programme, that is not our price protocol – it is not a flat real-price protocol – so I would be surprised if Alex can answer specifically for flat real 50 with the range –

ALEX ARCHILA: I have a better answer than that. If you go to the appendix, we have given you, for each band of prices, the estimated ultimate recoveries (EURs), the operating costs, the initial productions (IPs), the capital costs and the time it takes to drill, so that you can see the average pool of that. I will let you calculate your own returns.

MENNO SANDERSE, MORGAN STANLEY: Clearly, a lot has changed since 2013, when we were in Houston and you took us through this business. It is clearly a much better business, but one thing has not changed. There are huge IRRs, which are all fantastic, but the free cash flow is breakeven in the next two years and there is a lot of promise three years out. What am I still missing? Is it really driven by the fact that you are just depleting so quickly that this is just a painful business, no matter how many nice wells you drill?

STEVE PASTOR: Clearly, our price outlook is different than it was in 2013, and I think we could just look in a mirror. For anyone in the room who was at that investor presentation in 2013, our price outlook today is significantly different. We play against our prospective outlook, and therein lies the primary difference. Offsetting that significant decline in price, however, there has been, as I said before, better than our best expectation in terms of productivity. I gave an example two days in a town hall that we had in our London office – and we talked about this in 2013 – of driving productivity in our shale-well drilling. We talked about a pacesetter approach. I do not know if you remember that, but the way we described that is that we break a well down into each of the individual steps required to drill and complete that well: each hole section and each activity – running or cementing the casing, whatever that circumstance might be.

At the time, we were running a very high-number array. We look for the best of the best performance against each of that, we aggregate that and we say that that is the pacesetter. We then try to replicate that best practice and achieve that pacesetter performance. In 2013, our pacesetter wells in the Black Hawk were in the mid-teens, fourteen, fifteen days a well if you look back at the presentation. Today, as I described before, the wells that we have drilled so far year to date are sub nine days per well, again exceeding our wildest expectations. Please keep in perspective that, although the significantly lower prices have masked our tremendous performance with our onshore assets, we have done extraordinary things to improve in terms of costs, capital productivity, and rate and recovery.

ALEX ARCHILA: Let me add another perspective. Steve acknowledged the price issue in the acquisition but, going forward, in some of the scenarios that we showed you, we generate $3 billion of net cash flow within five years. That is more than what the whole company did in the past year. In terms of characterising the opportunity as not material or not profitable, I have to acknowledge that, clearly, at $50 per barrel, you are in a business that pays for itself, but that, in and of itself, is an option as well. That is another way to see your perspective

STEVE PASTOR: That is a great point, and I would add that we have lobbied hard to cut that prospective free cash flow in a different way, which did not show as much history but showed a bit more future. What you see is just the start of extraordinary free-cash-flow potential and, as Alex said, in those scenarios we are just getting on step with production, and that free cash flow then continues into the next decade.

MICHELLE TURNER: I would also add that, with those scenarios, we are at least neutral, if not positive, free cash flow, which is different than what we would have shown in the past. I agree that the history is really reflective of the difference, the change and the discipline that we have around how we are running this business now.

LOUISE HOUGH, UBS: You said in your presentation that, at the mid-point of consensus oil prices for FY18 and FY19, which look, if I am reading the chart correctly, to be $60-65 WTI, you will be marginally cash-flow-positive in those years. However, if we look at the numbers for those years for the US independents, certainly the bigger ones, they are materially cashflow positive in those years, and they are growing rather faster. Is this simply a function of your bigger weighting towards gas, or is there anything else making you less cashflow positive than your bigger peers in the US shale?

STEVE PASTOR: Well, I cannot speak specifically to the comparisons that you just gave, but I would say that it is largely a function of the scenario that we showed, and the fact that we are ramping production in those scenarios. We have some significant capital spend that enables the value maximising cashflow profile beyond that. Alex, I do not know if you want to –

ALEX ARCHILA: Yes, that is for sure, Steve. The only other thing I would add, to add some colour to your perspective on that, is: at the Haynesville we had a fairly chunky amount of ‘take or pays’ in transportation, as I have mentioned. So I will not opine on how others manage that, but we do have that element. However, that goes down through time, and it ends at around FY21. More importantly, if we succeed in our efforts and do our hedging programme going forward and increasing, we will be capitalising on that existing transportation volume and have a much better cashflow position than you would have otherwise had without the hedge.

STEVE PASTOR: Thank you, Alex. Let us take one from the phone now, please.

HAYDEN BAIRSTOW, MACQUARIE: Thank you very much, guys. Just a couple of quick ones from me. Firstly, just on the hedging volumes, how much of your hedging requirements will largely be driven by decisions of your non operative wells and your JV partners, and how much they decide to go ahead with? Is that a key driver of how much gas hedging you will have to do? Secondly, just back to the IRRs on these wells, the number of wells you have a 15% IRR at a $50 or less oil price, yet the business, as a few people have mentioned, remains cashflow neutral at that level, and production neutral. Is that the right number we should be looking at, or is 15% a nice number for the well by well decision, but the business as a whole needs to be considering much higher IRRs to get a decent cash return for BHP as a group?

STEVE PASTOR: To address the first part of your question and be clear: non op production across our shale leverage position is absolutely not a factor for us when it comes to the decision to hedge gas price. That decision is based fully on our ability to accelerate development of otherwise longer dated gas options at a lower risk, and secure quite competitive returns on investment. To your second question, I probably did not catch that one right; did you guys get that?

ALEX ARCHILA: I think the second question had to do with ‘Since at $50 we see cashflow neutral, do you need a higher return than what we are showing in the chart?’ I think that is the question, but I would appreciate a clarification again.

STEVE PASTOR: If I understood it right, I would just say that decisions on investability across the BHP Billiton Group come from a disciplined approach to the capital allocation approach that we described before. Peter Bevan described it extraordinarily well in some recent investor roadshows. I want to talk about across the Group, as opposed to very specifically within BHP Petroleum. He talked about how we start with available cash that we generate. Then we have some things that are required to safely and sustainably deliver our base performance. This year I believe he was talking about guidance for 2017. Call it $2 billion across the Group required for capital sustainability.

Then you get into more discretion, and the options that we have are between reducing debt and strengthening the balance sheet, topping up the dividend, and investing in value generative capital investment opportunities. It is across that suite of opportunities that we try to achieve the maximum balance. This year, across the Group, we have given guidance; it is a bit dated, it was two months or so ago, from when we were making the rounds and announcing the results from fiscal year 2016, that at spot prices we can generate $7 billion dollars in free cash. Peter went on to describe that that is enough to achieve everything that we aspire to in terms of reducing our debt, improving our balance sheet and strengthening our credit rating; topping up the dividend, potentially, and not starving any opportunity of capital that is worthy of capital.

The last thing I would say is that Alex talks a lot about this 15% investability threshold. There is plenty of resource and value at a lower investability threshold than that. That is still north of our cost of capital, and NPV positive. What we are trying to do here, however, is to be as transparent as we possibly can, to assist you in building your models and doing your own independent valuation work as to what we have in our portfolio.

ALEX ARCHILA: The one thing I would add to that, Steve, is that maybe behind Hayden's question is: 'Okay, so if you have a significant number of wells of less than 15, why are you not investing in those now?' Maybe that is part of the question. The answer to that is, as I have described to you, we are being very disciplined about how we move forward with spending money. Our trials at Eagle Ford are progressing very positively, and therefore we called that chart the 'Expected Case', as you saw there in the title. However, I still want to conclude the technical assessment of those. Likewise, in the Permian you could say, 'Well, you have a whole bunch of wells with less than 15%, why do you not do them?' We need to do a few things in there. First, we need to advance our midstream facility, which is important to optimise the value of the production, and we also need to do some spacing and staggered tests to make sure that we are addressing the optimum development. Finally, I would add to your question that, as Steve said earlier, we do not need to rush into investment. We have several commodities in the portfolio that attract investment at the right prices for that commodity. We were recently in $42 43 oil. We do not feel compelled to be burning our inventory through that.

STEVE PASTOR: Thank you, Alex. Let us take another question from the phone, please.

DUNCAN SIMMONDS, BANK OF AMERICA: Thank you very much, Steve. I have two questions. The first one is: could you give us some sort of idea about the monetisation potential in your gas business, say on a resource position, or even on a wells basis, so we can get some sense of magnitude there? Secondly, if we can just broach midstream monetisation in the Eagle Ford, what are the puts and takes there, and do you think there is the opportunity for you to release some capital effectively through a sale and leaseback? Thank you.

STEVE PASTOR: Duncan, thank you very much for the question. I know that you know that I cannot answer that question directly. I know you know that. We will find out; we will bundle up the parts of the Haynesville and the Hawkville that Alex showed you on a map, and we will do that. Actually, we have already done it, and we will be putting that out to the market to assess what the market thinks is fair value for that. Then we will test it against our own internal valuation and make a decision there.

I am talking about the upstream aspects of that, selling the parts that are outside what Alex showed on the map. On the midstream, before asking Alex to elaborate, I would say that we have been very clear that we create the best margins in large, long–life, low cost upstream assets. However, where midstream is the enabler for us to achieve the potential from our upstream assets, then owning and operating and doing that as effectively as we possibly can is part of enabling that. It is part of the strategy. Now, where we get to a point with our midstream position where we are confident in the availability of that position to support our upstream investments and outlook, then absolutely, we would consider the possibility of monetising the midstream. However, it would have to be in a way that is both for value, and also gives us that confidence and surety, if you will, of the availability to enable our upstream investments. Alex?

ALEX ARCHILA: Yes, what I would add to that is: what we can give you is that, during the remarks I made, I mentioned to you that what we are planning to divest is the parts of the portfolio that are long dated dry gas. I mentioned to you in my remarks that that is largely the non-operative portion of the Haynesville, when we speak about the Haynesville. I will let you understand our portfolio, how much is operated and non-operated, but it would be in that. That is one piece that I can give you on the Haynesville.

Another thing that I can give you on the Hawkville, which I already mentioned in my remarks, is that Hawkville is composed of two pieces. If you know the geology, we have a very liquid rich piece, and then we have areas that are fairly dry gas. When we look at our gas portfolio, we have the best of the best in Haynesville, so when would I take care of those drier Hawkville opportunities in my portfolio is what is driving that. However, as you will see, what portion is where in the maps will help you to see whether it is material or not to our value.

STEVE PASTOR: Quickly, before taking the next question again from the phone, I would just say – and maybe Alex will elaborate – that it is a bit of a moving target, and usually moving in a positive direction in terms of capital productivity and subsurface performance. Take, for example, in the Hawkville: some of the completion jobs that we are seeing done there, and the performance that we are seeing in the Hawkville, just as I talked about the costs exceeding our even most optimistic expectations, the subsurface performance is exceeding even our most optimistic expectations. There are some drier gas areas of the Hawkville that are starting to be competitive with the core of the Haynesville. There is a bit of a variation across the place.

MICHELLE TURNER: It really talks to how dynamic it is, as well, when we are talking about the valuations. I just want to foot-stomp both of their comments: these deals do have to be value accretive. We are not looking to just sell to sell, and that will be the bottom line from a priority perspective.

STEVE PASTOR: Thank you, Michelle, that is a good reminder.

ALEX ARCHILA: Yes, thank you for that.

STEVE PASTOR: Okay, we will take one more from the phone and then we will come back to the room.

PAUL YOUNG, DEUTSCHE BANK: Hi, Steve and Alex, once again. Just talking about free cashflow again, it never eventuated in the Blackhawk – not just because of the decline in the oil price and the lack of hedging, but also due to that significant investment in midstream. If I recall from the December 2013 site visit, you were planning on spending, and have now spent, about $1.5 billion on central delivery points. You had the pipeline Spaghetti Junction and pad development, and Eagle Ford. I just wonder: you talked about the Permian and what level of investment is required for the midstream. Do your IRR estimates include the spend? Thank you.

STEVE PASTOR: Thank you, Paul. To be clear, we have been and remain cashflow positive in the Blackhawk. I just want to qualify that. However, I appreciate that the further part of your question is around our strategy for investing in the midstream. As Alex alluded to – and I will let him describe the details – we are considering a different approach from the one Petrohawk had taken, and which we have followed up following the acquisition, on both the midstream and the transportation. Alex, you may want to describe what our case to beat is on our midstream investment for the Permian position.

ALEX ARCHILA: Yes, absolutely. If you have visited Pecos, or Odessa, or anywhere where the acreage is in the Delaware, you will know that certain areas in that part of Texas have third party gas plant processing, but have very little infrastructure connecting wells and pads to that gas processing. What we have done, in the calculations we have given you there, is to assume that we have used a third party solution to our midstream and utilised tariffs corresponding to that into the economics. That is the assumption we have made. I do not think I will give you more detail than that, because you can simply calculate how the midstream numbers work by yourselves, but you should be able to back calculate the tariff.

The logic is sound. First of all, we have not made a complete decision on it, but we want to make it based on value.

STEVE PASTOR: Great point: I think it is wise to not elaborate beyond that, although there are some other differences in the investment philosophy that we would take today in terms of take or pay versus dedication of volumes, and other trade–offs that we have in there that do not lock us into a particular volume profile that could then come back and bite us. Okay, one more from the room, and then I do want to honour the fact that we are a little bit past 11.15; I do want to honour the break. One more from the room?

JAKE GREENBERG, BANK OF AMERICA MERRILL LYNCH: Thank you very much, just a couple of follow ups on the Haynesville. Can you just explain to us what the IRR is if you do include the unutilised transport cost? Then, assuming that you can continue to achieve these 30% returns, can you help us understand why you would not hedge more production to utilise that transportation? Going back to the first presentation that you gave, in terms of M&A, do you have any restrictions on geography? From the mining side, we are used to thinking of BHP as very much OECD based. You have assets in Algeria and Pakistan; are you looking potentially to be in Guyana and East Africa, or are you thinking more along the lines of OECD? Lastly, in Michiel's presentation, on slide 7, I was just wondering what assumptions you were using for the development of battery storage for wind and solar, and whether that is included in that slide on slide 7.

STEVE PASTOR: Great, how about this? That was really clever how you made one last question into three last questions. Alex, if you would not mind taking number one, about the economics of the core Haynesville with the transportation?

ALEX ARCHILA: Yes.

STEVE PASTOR: I will take the second one, and Michiel can take the third. Is that okay?

ALEX ARCHILA: Yes, yes. Let me tell you, the effect of including the transportation in the economics is that it does reduce the economics. They are above cost of capital, but for commercial reasons we are not disclosing to you what those are. Clearly, the issue is that when you put them full cycle, you have to compare them with the rest of the portfolio that we have in petroleum in the rest of the world to invest. I will leave that one there.

STEVE PASTOR: That is right. It makes sense for us to make investment decisions on a go forward basis. If we have under- or unutilised transportation capacity, and we can make an investment decision, as we are making in the core of the Haynesville, that returns on a go forward basis, excluding some cost, 30% plus rates of return, we should do that and we should grow that. That was maybe the second part of your question: if we can do that, are we planning on doing more of that? We have a quarterly activity and investment review coming up in two weeks, on 24 October, and that will be squarely on the agenda: in the case to beat, the recommendation coming forward is to scale that up. Alex demonstrated that, showed that in his slides today. We call it a surge in the Haynesville, which makes further use of that latent capacity of underutilised transportation.

Quickly, to your second question about how above ground risk, if you will, factors into our decisions as to where we may or may not play, when it comes to inorganic growth, it is a factor. It is a key factor; it is not the only factor. We have demonstrated that. When it comes to places like Algeria and Pakistan, clearly they have higher above ground risks than Australia and the US. Mexico and Brazil have higher above ground risk than Australia and the US. It is a factor, and we consider that; but I can tell you that there are a multitude of factors, and those go into our filtering criteria to decide what we carry forward. They ultimately go into our decision that we take forward to the Board, and the Board's decision as to whether or not they will support it.

MICHIEL HOOVERS: Your last question, I think, was related to the power generation in the US, and how that would split, and different sources? As I said in my presentation, we see gas continue to grow, and we also see renewables grow as well. It is mainly at the expense of coal in the US. I do not know the exact numbers that we have assumed for solar and wind, but we could get that for you.

STEVE PASTOR: Thank you, Michiel. Now we will take a break until 11.30 and we will start promptly in about 10 minutes. Thank you very much.

7. Conventional

GERALDINE SLATTERY, ASSET PRESIDENT, CONVENTIONAL PETROLEUM: My name is Geraldine Slattery and I am the Asset President of the Conventional Petroleum business. I have a long history with BHP Billiton Petroleum – 22 years in fact – in Australia, in the US and in the UK, in roles of increasing responsibility in operations, in engineering, in HSE and in management. Prior to this current role, some of my recent roles included being General Manager of our Oil and Gas business in Australia, and prior to that, General Manager of our Haynesville and Fayetteville dry gas assets in the Onshore Shale.

Over the next 20 minutes, I will share with you the Conventional Petroleum strategy, in the near to the medium term, before handing over to Niall McCormick, who will take you through our longer term growth strategy.

Before I begin, I will go back to the disclaimer and remind you of its importance to today's presentation.

Over the course of this presentation, I will share four things with you. The first is our high quality conventional asset portfolio and the strong foundation it creates for our global Petroleum business. The second is our demonstrated operating and development capabilities, and how that underpins our success today, but also supports our future growth. The third is our high return, rich pipeline of brownfield opportunities over the five year outlook, and our greenfield projects in the medium term. Finally, I will share our plans to extend the production runway in Conventional, through our exploration program and our ability to accelerate development to first production.

Our global portfolio is concentrated in the Gulf of Mexico and in Australia. We also have a significant shallow water Trinidad &Tobago gas development, as well as non-operated interests in the North Sea and in Algeria. We expect our Conventional business to produce approximately 125 MMboe in FY17, with two thirds of that in Australia and about one–third coming from our Gulf of Mexico assets. In addition to being sizeable contributors to BHP Billiton's petroleum production, our asset base ranks us as the second largest producer in Australia and the fourth largest producer in the Gulf of Mexico, in the deepwater.

This level of portfolio concentration enables us to acquire basin-wide geological understanding of the resource, develop effective relationships with host governments, and also acquire a detailed understanding of the operating conditions and the regulatory environment. These are the factors that underpin some of our competitive advantages, which I will share with you a little bit later.

Let me just spend a few moments on the significant assets within our two production heartlands, firstly in Australia, in Bass Strait. Since its discovery in the 1960s, the Bass Strait oil and gas fields have been prolific and reliable producers. Bass Strait is our highest producer by volume, and carries significant high return undeveloped resource, yet to be monetized, which I will come back to a little later. In the North West Shelf, we are a one sixth participant in the North West Shelf LNG, Oil and Domestic Gas Project, which is one of the world's largest LNG producers, operated by Woodside. It is a material producer today, and it also has a suite of high return brownfield tie-in projects. In addition, it is also strategically located relative to accessible gas reserves, offering potential brownfield LNG expansion capacity in the medium to longer term.

In the Gulf of Mexico, we operate two deepwater oil and gas fields commissioned in 2008 and 2009: Shenzi, with a 44 per cent interest and Neptune, with a 35 per cent interest. We also hold non-operating interests in two adjacent fields – Atlantis, at 44%, and Mad Dog, at 23.9%. These are two of the largest fields in the Gulf of Mexico, with decades of production and development before us.

Turning now to our resource base, as I just spoke to, we are concentrated in Australia and the Gulf of Mexico. The quality nature of our assets is reinforced through the continued contribution of high margin liquids to our product mix, accounting for half of projected volumes over the five year outlook 40% of the remaining 2P reserves.

Of the overall resource base, almost 60% are contingent resources, illustrating the significant remaining development potential within the portfolio. We have clear line of sight to the development plans required to convert a large proportion of the contingent resources into future production with Mad Dog Phase 2, Bass Strait undeveloped gas resources, and Scarborough accounting for the majority.

Let me now speak to the financial contribution made by our conventional assets. These assets have been, and continue to be, the cash generating foundation of our Petroleum Business, providing the highest EBITDA margin across the BHP Billiton group at approximately 70%. Over the next two years, Conventional is forecast to generate approximately US$3.5 billion in EBITDA and US$2.7 billion in free cash flow per annum, based on consensus pricing.

Average Return on Capital Employed over the same period, even with investment but no revenue contribution from Mad Dog Phase 2 projects, is forecast at a very competitive 15%. This strong performance is attributable to improving capital productivity, industry leading uptime performance, which I will come back to, continuing to challenge and optimise our unit operating costs, as Michelle spoke to, and finally, divestment of lower margin assets such as Pakistan.

Under the current development plan, we expect capital to be approximately $10 billion per annum over the five-year outlook with FY17 and FY18 being slightly less than that, at about $800 million per annum, until such time as the Mad Dog Phase 2 project begins to ramp up from FY18, assuming FID goes ahead in this financial year.

Turning now to our operating and development capabilities – which is something I get excited about – in addition to strong and profitable assets, we are incredibly proud of the sustainability and the resilience of our operating and development capabilities, particularly in Deep Water and starting with deepwater drilling. Our industry–leading drilling performance continues to be a source of competitive advantage to us. We compete with the Super Majors in the Deep Water, and this is illustrated by the chart on the bottom left, which shows the average BHP Billiton Gulf of Mexico drill time of 2.85 days per 1,000ft. You see our peers are alongside us. This performance is attributable to a strong continuous improvement culture – the drive to be the best, and to do it better every time.

Turning now to uptime, at our operated facilities, we continue to maintain industry- and basin leading operated uptime, increasing total uptime from 92% in FY14 to 96% in FY16. This is underpinned by a high performance culture at our operated facilities, supported by effective reservoir management and maintenance strategies.

Finally, turning to our unit cash costs; on this, I will share with you a couple of examples that speak to our strong performance culture, both in maximising volumes and reducing costs. In Australia, in our Warehousing and Logistics, which is a big cost driver in an operated operation, we have partnered with our joint venture peers to make full use of latent marine, aviation and warehousing capacity, by sharing resources and support services, minimising unit costs in the process.

In Trinidad, at our offshore gas facilities in Trinidad, we are capturing market upside through improved reservoir management and facility debottlenecking at minimum cost. In the Gulf of Mexico, we are evaluating the application of gas injection technology to increase recovery rates. If this is successfully demonstrated, it will unlock a material resource within the easy access of existing infrastructure.

Finally, in a global sense, as you heard from Michelle, we are working hard at optimising our working capital though targeted management of inventory, payment terms to our contractors, and also our contract commercial terms.

Our continued focus on unit operating cash costs is demonstrated on the bottom right of your screen. This shows our Shenzi Deepwater operation, in production since 2009, continuing to demonstrate industry leading cost performance relative to our Super Major peers in proximity to us.

Let me now turn to our volume growth strategy, in the near and in the medium term. The profile on your right shows the volume growth wedges. First, we will continue to press and extract full value from our base assets through uptime, and through capturing full market potential through latent capacity. This will continue and always will be a priority for us. Secondly, the dark blue wedge represents a portfolio of high return brownfield projects. These projects arrest base decline from 13% to just 5% per annum over the full five year outlook. Thirdly, the green wedge beyond five years brings greenfield projects into production, notably the Mad Dog Phase 2 development and the Scarborough development in Western Australia. Finally, given our competitive advantages in deepwater, we are focused on replenishing our oil reserves. The light coloured 'Risked Exploration Success Scenario' wedge represents a success case profile associated with our current deepwater exploration portfolio, on which Niall will go into further detail with you.

We also continue to optimise our portfolio by ensuring we remain geographically focused in our production heartlands, and those areas such as the Mexico side of the Gulf of Mexico, where our skills and experiences are transferable.

This slide dives in a little bit deeper to that brownfield wedge that we saw on the previous slide. This wedge has a pipeline of multiple economically robust projects, already in execution within our production heartlands, as well as further near-term projects that we are currently evaluating. Collectively, these projects provide average nominal returns of 45%, and slow base decline to just 5%. By volume, over the five year period, 85% of these projects are already sanctioned or approved. These projects have been tested across a range of price scenarios, similar to what you saw with Alex in shale, and they remain economically robust even under consensus low prices.

These are well understood reservoirs with existing tie-in infrastructure, providing an attractive low risk source of future cash flow in accelerated timeframes. I will just touch on some of the details within these projects.

In Australia, in the North West Shelf, there are multiple subsea developments being delivered over a five year period providing predictable and phased gas reserves. These maximise the availability and they maximise the economic recovery of the gas resource, and are aligned with ullage availability in the offshore facilities, and also at the Karratha Gas Plant. In Bass Strait, a new onshore gas conditioning facility, adjacent to existing facilities in Longford, will be brought into production later on in this calendar year. This will monetise significant reserves from the recently developed CO2 rich Turrum and Kipper fields, and from future high CO2 reservoirs. Finally, in the Exmouth sub-basin, we continue to evaluate and appraise remaining resource potential, to leverage our existing infrastructure in Macedon and in offshore Pyrenees.

In the Gulf of Mexico, at Atlantis, in the current approved field development plan, there are a significant number of material field expansion opportunities, in addition to potential in-fills, undrilled segments, sidetracks and recompletions, giving us the potential to expand beyond the current approved development plan. In Mad Dog, development drilling from the Spar A facility resumed in 2013, following the loss of the original rig to a hurricane in 2008. Wells in the Mad Dog field are extremely prolific, with many development wells in the coming programme. The facility, indeed, will only reach nameplate capacity within this financial year, with a long development plan ahead of us. We also continue to evaluate future development potential at Shenzi, through enhanced oil recovery techniques, as I mentioned earlier, and/or further infill drilling targets.

In Trinidad, we have just completed the Angostura Phase 3 project, which achieved first production on schedule just last month. The three–well development is expected to add 2.8 million barrels of incremental oil and 400 bcf of incremental gas.

Beyond the existing suite of brownfield projects, greenfield projects provide medium–term volumes, particularly the Mad Dog Phase II Project. I will start with a few words on the Mad Dog field and on the development. The Mad Dog field is one of the largest oil fields in the Gulf of Mexico, with an estimated original oil in place volume of over 4 billion BOE, and a potential recoverable volume of 1.0 billion barrels.

The Mad Dog Phase II is the second development phase of the Mad Dog field, targeting the south and southwest segments of the field. The development consists of a wet tree subsea development of 22 wells, supported by a floating semi-submersible production and water injection facility. The Phase 2 project is an excellent example of how a once challenged deepwater project is now approaching FID with very compelling economics, and is expected to break even at well below $50 per barrel. In particular, the project capital costs have halved since its original development concept in 2013.

A number of things have contributed to that. Firstly, optimising the field development concept and the flow development plan; secondly, replacing bespoke solutions with simplified design specifications and industry standards, where it makes sense to do so; and thirdly, rebidding all major contracts and revising contracting strategies, to take full advantage of the deflated market. Finally, excellent collaboration and technical engagement between the co-owners have led to a significant proportion of this value. A final investment decision is expected in the next 6 months, which would enable development drilling to commence in the second half of 2018, and that would align with a first production date in 2022.

I will turn now to Scarborough, which as you will know is a large gas resource in the Carnarvon basin in Western Australia with adjacent smaller fields of North Scarborough, Thebe and Jupiter. Scarborough offers development concept optionality, be it FLNG or gas compression tied to one of the existing onshore facilities. It also has the potential to serve as a hub for developing adjacent stranded gas reserves from sub-economic fields in the basin. Whilst we would acknowledge that the current market is challenging for LNG, we remain confident on the long term prospects for Scarborough.

As I spoke to earlier, our deepwater drilling capabilities are as good as many in the industry, and indeed they are better than most. These capabilities are currently being leveraged in our exploration programme, which Niall will come to. Whilst Niall and the Exploration team are focused on drilling exploration wells and finding resources, we in the Conventional Assets are focused on shortening the development timeline from discovery to first production, and ensuring that projects are economics at sub $50 per barrel.

To frame this challenge internally, we have set ourselves a bold target of reducing development timelines by 20% relative to industry average. Such acceleration will lower break even costs and add NPV. Our confidence in achieving this target is based on tangible actions that are already underway, such as using Metocean and Geotechnical data to pre-screen development concepts in parallel with appraisal drilling. We are developing relationships with key vendors and equipment providers, and applying standard solutions versus customised designs, which will not only accelerate timelines, but also lower our operating costs. We are engaging key industry suppliers to understand not only current technologies, but also the potential for extending those technologies to future commercial applications. Finally, we are leveraging our continuous improvement culture, as demonstrated in our deepwater drilling and operational performance.

In conclusion, I will return to the four key themes. Firstly, we have low cost assets, concentrated in stable political environments, which are forecast to produce robust earnings and free cashflows. Secondly, we continue to maintain superior development and operational capabilities, demonstrated through our deepwater drilling performance, our uptime performance and our cash costs. Thirdly, we are executing an attractive growth pipeline in the five year outlook, through a portfolio of high return, brownfield projects, and in the medium term, through greenfield projects, with Mad Dog Phase II expected to go to FID in this financial year. Finally, we are ready to support future developments following exploration success or acquisition success, through the work we are doing to enable a 20% reduction in development timelines.

Thank you for your interest, ladies and gentlemen, and your attention. I will now hand you over to Niall McCormack, VP of Exploration, who will take you through the exploration programme, and then I will then rejoin him to respond to questions. Thank you.

8. Exploration

NIALL MCCORMACK, VICE PRESIDENT, EXPLORATION FOR PETROLEUM: Thank you, Geraldine, and good morning, ladies and gentlemen, it is a pleasure to be here this afternoon. Thank you very much for your time and for your interest. My name is Niall McCormack and I am the Vice President of Exploration for Petroleum. I have been with BHP Billiton for about four and a half years now, and before that I have worked around the world, on six continents, exploring for oil and gas.

Geraldine has given you a comprehensive overview of our high quality conventional asset base, our strong operating capability and our project pipeline of brownfield and greenfield. Given our advantage in this area, it is obvious that we want more reserves to ensure more high margins and returns from our conventional business, for decades to come.

Again I will draw your attention – hopefully for the last time today – to the disclaimer, but I do ask that you read it; it is definitely pertinent when we are talking about exploration.

Over the course of this presentation, I will bring you through our definition of Tier 1, and how this has re-focused our exploration program, the opportunities that we have prioritized and how we have simplified our portfolio over the past four years. How we work is centred around the right technology, the right data and the right processes. We will look at our recent results and the forward program. We will touch on the benefits of investing counter cyclically, as we take advantage of the low cost of acreage and seismic data, and the ability to appraise and develop in a low cost world. I will discuss how a combination of the simplified operating model, coupled with technology, can significantly reduce our cycle time in all of the upstream phases, including exploration.

With huge progress already made in the exploration sphere, you will see how we are looking at value in that space. The geological potential, coupled with the excellence in project execution, mean that we can bring any future discoveries into production faster, more cheaply and more safely than our competitors, while ensuring maximum value for the shareholder. We will finish up by looking at the potential production streams that could come from our exploration portfolio.

Stepping back a little bit, many people in exploration believe that you can offset the high risk with more wells in more basins: high risk equals high reward. We fundamentally do not believe this. While we are, indeed, frontier explorers, we look at exploration as value accretive options, and will only proceed to test opportunities that we really, truly believe will work. Over the last four years we have transformed our portfolio. A view of our global exploration portfolio five years ago indicates that we were in over 12 countries, across many plays, with a very low chance of success.

While it sounds simple, the key to delivering volume and subsequent value is identifying, accessing and exploiting only the best basins. A recent Wood Mackenzie study of exploration demonstrated quite effectively that 90% of the value created by the Majors from exploration was created in just 10% of the basins. This seemingly confirms our view that value is created not by the number of global basins that you explore in, or the number of wells that you are drilling, but, actually, ensuring that you have positioned yourself in the best basins with the right geological characteristics under the right fiscal terms.

How do we identify which basins are the best basins? We step back and we ask ourselves three very basic questions: is there a world class source rock? Is there a big reservoir system? Are there large traps? The answer to this informs our view of the global endowment for petroleum. Our most recent assessment of this in 2012 focused our activity on the basins where the rocks supported the potential for Tier 1. With that, what is our definition of Tier 1? Our definition of Tier 1 is a petroleum system where we can get 100,000 barrels of oil a day. To deliver that, we need field sizes of greater than 250 million barrels, which in turn means a petroleum system of over 5 billion barrels yet to be found, of which we need to capture one billion barrels net.

Additionally, we need fiscal terms that allow opportunities to compete for investment with the greater BHP Billiton portfolio. We recognise that we have a range of growth options across each of our major commodities and across BHP Billiton. Petroleum exploration must deliver both materiality and margin. We aim to provide developments at less than $50 per barrel. We believe we can best deliver this by focusing our activities and our exploration on liquids-prone systems. To capture the volume and the value, you have to be an early mover. To be clear, we are not looking for one-off opportunities; we are looking for those areas where we can explore for a decade and where we can produce for half a century. This is best typified by the Bass Strait, which has been a cornerstone asset for BHP Billiton since the original discovery well back in 1965, Barracouta 1.

With that, over the last four years, our focus on our definition of Tier 1, combined with the geological analysis of what drives the potential for liquids-prone systems, has transformed our portfolio to focus on just three areas: the Gulf of Mexico; the Caribbean; and the Beagle Basin in Western Australia. In addition to these plays, we see significant potential in Mexican deepwater and are in the process of evaluating this potential ahead of the initial deepwater bid round later this year.

We have acquired the right data across each of our basins. Like a scalpel to a surgeon, seismic data is the critical tool that underpins our understanding of potential. This includes licensing and processing over 200,000 km^2 of 3D in the Gulf of Mexico; acquiring the largest ever proprietary seismic acquisition done by an IOC in Trinidad and Tobago; and accessing over 40,000 km^2in the greater Beagle sub-basin area in Western Australia. These seismic datasets have allowed us to do the next set of analysis, which is an interrogation of the 'plate to the pore'. That is getting the understanding going from the scale of the tectonic plate to the pore space in the rock. From this, we are now focused on two plays in the Gulf of Mexico, three in Trinidad and Tobago and one in the Northern Beagle Basin. While we are in the early days of testing these plays, the early results indicate that these basins and plays gave the resource potential consistent with our definition of Tier 1.

Aligned with our strategy, we have accessed multi-billion barrel liquid potential across each basin. Consistent with the Tier 1 focus, most of this potential is in pool sizes greater than 250 million barrels unrisked. In addition, our evaluation of the Trinidad and Tobago following the recent LeClerc well results indicates the potential for a material gas province with a potential longer-term tie-in to higher-margin LNG. The risk in exploration is clear. However, the wells we are drilling as part of the current programme will polarise these opportunities and provide us the necessary feedback to inform the next phase and the potential of these basins.

An example of positive feedback is evident in the Trinidad and Tobago gas story. Our initial well, coupled with our regional evaluation, has indicated significant gas potential in addition to multiple liquid plays. We see exploration of sequential options. If we see positive or negative feedback either on seismic or with the drill bit, we have the flexibility and the ability to refocus our spend elsewhere. We will only increase investment on success. Over the next few years, we are well positioned to deliver material organic growth and deliver significant value to BHP Billiton.

We have completed our portfolio rationalisation and are now we are moving into the executing against our Tier 1 strategy with the drill bit. Over the past year, we have drilled three material exploration and appraisal wells with 100% success. We have timed our exploration program to minimize cost while maximizing value. Several years ago, when the oil price and cost base were high, we focused our efforts on data acquisition, play evaluation and portfolio rationalisation. During the 2012-2014 period, we had the lowest expenditure of any in our peer group and significantly underspent our major deepwater competitors. Now, as we complete the pivot to execution and test, we are accelerating our exploration efforts to take advantage of the low-cost environment. While we cannot pretend to have a crystal ball, our view of the long-term oil price remains bullish. Explore low; produce high.

Our increase in FY2017 spend and investment is because of the success. And, as I said, we will only increase spend when we have made discoveries that have the potential to become commercial, that justify appraisal and compete in the portfolio. Over the next three years, we expect to drill 6-8 high-impact wells in the Gulf of Mexico, Trinidad and Tobago and, potentially, Western Australia. Upon success in exploration, you want to see more moving down into this line. You want to see us appraising opportunities that have the potential to be developed and commercialised – and which are competitive in the portfolio.

In terms of the Gulf Mexico, we are actively exploring two plays there today: the Miocene play in the Central Gulf of Mexico, central Green Canyon; and the Paleogene in the Western Gulf of Mexico, which is an extension of the proven Perdido Trend. The Miocene play in Green Canyon leverages our understanding from our operations in Shenzi, Mad

Dog and Atlantis, combining the work of the Conventional Asset team, who work for Geraldine, and the Exploration team. They identified significant untested potential in the Miocene to the north of Shenzi.

The first well of the current exploration program was Shenzi North. Oil was encountered and appraisal of the basin was accelerated with the drilling of Caicos well, in which, as was just announced this morning, oil was found in multiple horizons. With this success we are now moving to test the Wildling appraisal location after the rig returns from Trinidad and Tobago. We have identified further running room of this play in an adjacent sub-basin and are in the process of planning an exploration well to test this potential. Success at either Wilding or Scimitar, as it is called, would result in high-margin oil which that is robustly commercial at prices below $50 a barrel.

Moving to the western Gulf of Mexico, we have accessed a concentrated and material position through strategic acreage trades and modest bids at recent lease sales. We are now the dominant operator in the US side of the subsalt Perdido trend, an extension of where the discoveries have been made in the Mexican deepwater. We have 152 blocks with 60-100% equity position, and we operate all. The acreage has multi-billion barrel potential in a large reservoir system overlying a world-class source rock. In addition, recent seismic imaging has identified a dozen significant leads and prospects in the area. Success in the Paleogene, however, takes more than just resource size. While the industry has discovered large resources to the east of our acreage position, much of this resource will have a high unit cost due to either poor rock quality or fluid quality.

We are leveraging our seismic data and out understanding of the regional geology to better define the leads and prospects. Within that space, the indication is that our acreage position, by design, is where fluid and geology 'sweet spot' occurs. Should we be successful, we expect the unit cost of this play to be competitive with the prolific Miocene play in central Green Canyon. We are planning on testing this in 2018.

Geology does not stop at borders – and neither does our assessment of petroleum systems. The Gulf of Mexico petroleum system, in and of itself, runs from Florida in the east, to the foothills of the Sierra Madre in the west and from the Yucatan in the south up to Louisiana in the north. BHP Billiton is uniquely qualified to undertake the evaluation of the Mexican deepwater, and we have leveraged our experience in deepwater, Green Canyon, our understanding in the Perdido fold belt, to work through our understanding of the Mexican sector of the Gulf of Mexico.

We have also capitalized on our understanding of the shale plays from the Haynesville and the Eagle Ford which, interestingly, are two of the source rocks for the potential deepwater systems. The geological analysis supports the potential for Tier 1. There has been limited activity to date, mainly in the Perdido, with high success rates. We are also evaluating the untested deepwater Salinas trend, which is an extension of the prolific shallow water Campache province. Today the changes in the Mexican oil sector are some of the most exciting in the industry. This year will see the first of four deepwater exploration licence rounds that are planned to take place annually.

As well as the Exploration opening, Pemex are looking to bring partners into their discoveries in the Perdido. This will be done through an open and transparent process, and we have submitted our prequalification for the Trion bid, which is planned for 5 December later this year. While we are encouraged by what we have seen to date, we are taking a disciplined approach to country entry, as Steve mentioned earlier. We are positioned to progress organic or inorganic access if, and only if, the geology and fiscal terms are value-accretive and competitive in the portfolio.

Moving further south, down to Trinidad, we have large, proven structures, world-class source rock and the relatively untested deepwater of Trinidad and Tobago and Barbados. In 2012, we identified that it had clear Tier 1 potential. From 2012-2014, we accessed nine operated licences in Trinidad and Tobago with 60-100% equity. In the past year, we signed two licences in Barbados, which we currently hold at 100%. We have acquired the right data to evaluate the play with over 21,000 square kilometres of high-fidelity 3D seismic in 2014.

Our portfolio in Trinidad and Tobago has multi-billion barrel oil potential across three plays: the southern Neogene; the northern Paleogene; and the northern Neogene. Additionally, we have a material portfolio of gas opportunities. We intend to drill eight wells in the deepwater of Trinidad and Tobago across two phases. In phase one drilling, which is currently underway, we have drilled an initial well in the Southern Neogene, which I will come back to in a minute, and we are currently drilling a well in the northern Paleogene.

The results of the first two play tests will be integrated into our analysis for phase two, which is planned to start in the second half of 2017. So far, we are encouraged by the results we have seen at LeClerc. We have made the first discovery in the deepwater Caribbean, with gas penetrated across multiple zones. Significant gas discoveries in the near term have the potential to hit the market in the mid-2020s, a time when both Trinidad and the LNG market have available capacity. We were also pleased to have oil shows deep in the well, a strong indication of a liquid-prone hydrocarbon system, which supports the potential for oil prospectivity in the southern Neogene play.

In the north, the first play test of the Paleogene is currently drilling, the Burrokeet well. For context here, we are testing new plays in the deepwater Caribbean over 100 kilometres away from the closest well control. Historically, these types of areas take more than one well to prove the presence of Tier 1. Actually, a very good example of that is the Miocene sub-salt play in southern Green Canyon, where it was the third well that actually opened up the play. With our results to date, our view of the chance of success in the region has increased, and we are well positioned to capture these volumes and the value of these plays.

To move, now, through to operational excellence, consistent with the focus you have heard all day in terms of operational excellence, we have identified what that looks like in Exploration. What we are trying here is to reduce cycle time while when we access a block to when we start to test the play. In effect, it is about delivering the right answer to the organisation, and delivering it faster. The key to this is having the right technology, the right data and the right processes. Historically, the industry has taken 5-6 years to drill their first play test in a new region after accessing the acreage. We now target three.

We have done this primarily in three ways. First, we are acquiring the rights to data as early as possible. We started acquisition in Trinidad and Tobago one month after the last block was signed. Secondly, we are investing in computing systems that allow for all the data to be accessible all the time. Today we have 5 petabytes of seismic data online 24/7/365. For context, that is about 9,500 years of music to listen to digitally, which is a lot of Beyoncé. And, finally, we are running our workflows in parallel rather than in sequence. The vertical integration of regional, prospect and early-appraisal work ensures that we can realise all possible synergies, while improving the ultimate handover between workflows. As Geraldine described, additionally, we are working to reduce our cycle time on discovery by 20%. We are benefitting from the simplified operating model of BHP Billiton, which facilitates a flatter organisation and deeper cross-functional expertise.

Overall, this gives us three major benefits. It improves integration of the technical work at all scales, across both surface and subsurface, which in turn reduces project risk and uncertainty. Secondly, it allows us to leverage well results sooner, enabling better strategic planning. Finally, time is, of course, money. On success, for a 300 million barrel oil field, the NPV increases by circa $100 million per year of acceleration.

To finish up – I suppose this is the punch line – we are exploring, consistent with our strategic mandate, for large, long-life, low-cost assets. We are focused on our core competencies in deepwater with a portfolio of Tier 1 opportunities and a bias for liquids, with high interest and operatorship. Over the last four years, we have built material positions in six plays across three basins; we are a dominant player in each of these plays; and we operate all our key exploration acreage. The portfolio has multi-billion barrel oil potential across the Gulf of Mexico, Trinidad and Tobago and Australia. Much of it is in pools of greater than 250 million barrels unrisked. Additionally, there is significant shallow gas potential in Trinidad and Tobago, as evidenced by the shallow gas found in LeClerc.

On a risked basis, our portfolio has the potential to deliver over 100 million barrels of oil equivalent per year to our production stream, including a risked 90 million barrels per year of oil. We are targeting large pool sizes in the deepwater, with IRR of over 15%, real, full cycle, and NPV per barrel of $5-10 a barrel, which are economic at less than $50 per barrel.

As you can see, while exploration risks are always high, our potential rewards are attractive. The petroleum exploration programme we have embarked upon is the most significant in many years, at a time when the industry is cutting back. This is aligned with our overall strategy and aims to create value by opening new plays with material volume-potential in areas that have attractive fiscal terms. We have found the first hydrocarbons in the deepwater of the Caribbean and have moved to the north and are currently drilling the first play test of the northern Paleogene. This is a high-quality portfolio of prospective options, which aims to add significant resource and value to the company. It is being worked and progressed by a world-class exploration team with leading-edge technology.

We are working on delivering high-quality projects at a fast pace in deepwater that maximize the value of our resources. Thank you for your time, ladies and gentlemen. I believe Geraldine and Steve will now join me to answer questions.

9. Questions and Answers

STEVE PASTOR: Thank you very much, Niall. We are now moving in to the final Q&A session for the briefing. We have about 25 minutes or so, which we are going to spend answering whatever remaining questions you are able to put into the room here. This is not just for Conventional and Exploration – although I do hope you have some good questions for both Niall and Geraldine. I will also invite Michiel, Michelle, Alex and myself to answer, depending on your question. Let us go ahead and get started – and then we will work towards that 12.45 close. Can we have the first question in the room, please?

TONY ROBSON, GLOBAL MINING RESEARCH: Thank you. On capex for Mad Dog 2, of course you will not comment because it has not been sanctioned or approved by the Board, but, if you could tell us what the capex was in 2013, it is half that. If not, given that we are mining analysts, not necessarily petroleum analysts, what is in the trade journals; what are the sell-side analysts suggesting, who cover your JV partners? Is there any guidance you can give us there in terms of gossip, please?

STEVE PASTOR: Tony, thank you for that. Geraldine, would you like to field that question.

GERALDINE SLATTERY: I can do. Probably, I can quote certainly what is in the press, now we are approaching FID with the operator. The capital cost back in 2013 was $20 billion and we are now below $10 billion. There are a number of things that have contributed to that: the development concept has changed completely from a spar development to a more conventional semi-sub development, but that is now the development concept. That came from collaboration, acknowledged by the operator, between the co-owners. We certainly played a large role in that through technical and managerial influencing.

The development plan has changed quite dramatically in terms of the number of wells and the placement of wells – and there is a host of other designed concept changes. The contracting strategies have changed quite markedly over time in terms of taking a much more competitive approach to the market by way of contracts that are bid and so forth. I am probably saying too much, because it is a non-operated project – but we are certainly very excited about the project and we will see what FID brings us, but we are confident.

STEVE PASTOR: Thank you, Geraldine. Do we have a second question?

JASON FAIRCLOUGH, BANK OF AMERICA MERRILL LYNCH: I have one here. It is just maybe a philosophical question on exploration, because it does seem that you get a lot more latitude to do greenfield exploration in petroleum versus what your colleagues in the minerals business do. Is that going to continue?

NIALL MCCORMACK: I think probably the best answer to that is that exploration competes for capital as part of the capital-allocation process in the same way as any other part of what we do does. Whether it is Mad Dog 2 or whether it is exploration in minerals, it is not independent of that process and they compete for that and with that. At times, it is hard to compare the scale of investment involved in minerals exploration versus petroleum exploration.

We are very focused across copper and petroleum in terms of what we are targeting and what we are trying to do. We are actually pretty well connected. Laura Tyler, the chief geoscientist, who works through Jean de Rivieres down in Chile, and myself talk on a regular basis. We understand what both sides are doing but, from an investment perspective, we compete for capital within that and we are within the capital-allocation framework. It is definitively not a free ride in any shape or form – or treated any different to any other major investment we are doing.

STEVE PASTOR: Thank you, Niall. To elaborate for a moment on that, I would say we have been very clear across the corporation that we see the best market opportunities for growth in both copper and oil. It comes back to fundamentals, and the fact that in both copper and oil we face both naturally declining production – or grade decline, as is the case in copper – and that presents a much more significant supply opportunity than we see across our other commodities.

Therein lies the reason why we are exploring, where it is valuable to do so, in oil and copper. I would also say – not to put too much pressure on Niall and the exploration team – that that is also a function of our confidence and the chance of success for Tier 1 assets to come out of this exploration programme. Further to that, we have decisively taken the decision to accelerate this programme and see what we have. This has been a completely revamped programme, as Niall described, over the last four or five years. We are in positions that we think offer the greatest potential not only from a subsurface perspective but married up with the economic potential – and we are accelerating our tests of that.

I will leave it at that. Success breeds success – and the alternative can also be said. It is a fact of the matter. I have absolute, high confidence in our success. We have already demonstrated, as Niall said, that we have the smell of it. We are onto the scent, both in Trinidad and Tobago and with the discovered oil we have seen north of Shenzi. We have been really smart and very effective about growing that position quietly and cost-effectively to give us lots of running ground there.

MENNO SANDERSE, MORGAN STANLEY: I have three small questions. The first one is for Geraldine on the Conventional capex guidance of $1 billion for the next five years. Does that include all the brownfield you talked about or only the 85% that has been approved?

Secondly, forgive me: I am just a finance dummy. Could you help me and explain whether less than $10 billion for Mad Dog 2 is good or $20 billion was just insane?

STEVE PASTOR: Be careful, Geraldine. That is really like a lawyer saying, 'I really do not know the answer to this question.'

MENNO SANDERSE: I really do not know. Maybe the $20 billion is insane and maybe the $10 billion is not so good. My final one for now is this. You said you had a world-class team and a new approach, which I am willing to believe, but can you illustrate how the world-class team has been built? Did you hire new people? Can I get a bit more feeling?

GERALDINE SLATTERY: I think your question was on the capital guidance. I saw two numbers of about $5 billion over the five-year outlook. That includes the full brownfields outlook. My point around the 75% is really intended to demonstrate the certainty and the confidence of that particular wedge, but it does include some capital in the five-year outlook for projects that have been studied and we anticipate will be approved. The other thing that is in that five-year capital outlook is that it is assumed FID will happen for the Mad Dog project. About 35% of that, over the five-year outlook, is for Mad Dog. We also have about 15-18% for licence to operate, compliance, risk reduction, making sure we always maintain the integrity of our security.

I probably should not comment on the Mad Dog question, given that we are touching FID. We are very excited by the Mad Dog project and the economics that we currently have. We are just weeks from FID, so just wait a little longer there.

NIALL MCCORMACK: I can give you a little bit of colour in terms of the answer to the last one. About five years ago, 50% of the people in Exploration in BHP Billiton had more than 25 years' experience, but over 50% of them had less than five years with the company. Essentially, there was no consistent approach, no consistent way of doing anything. It really was not pulled together in any strong form within that space.

While we have seen some major changes in terms of personnel, one of the big things we did was sit back and say, 'How do we want to explore?' We looked at our processes and our technical work and it was literally like different companies talking to each other. We sat down and we created a process called Volume, Risk and Value, which is a consistent way we approach prospecting at every scale. We have worked through that over the last four years. We have put in a tight assurance and brought in a group to actually do that within the company. There has been a lot of changes on the personnel, a lot of changes on the process side in terms of how we approach what we do, bringing a level of consistency and technical rigour.

We went through the analysis of what we do well and what we do badly, and what we found was overall quite a bit of the technical work was good. There were some gaps, which we did fill, but, actually, on the back end what we saw was that decision-making was not always aligned with the process. There was this idea of, 'It has a chance; we have to give it a punt,' which we call hiding behind risk. That is different from actually saying, 'Look, if we do not think this is going to work, or if it is a one in 20, there is no way we should be doing it' – because in reality the one in 20s in exploration do not come in.

There was a culture change, a process change and a people change. I would say the culture and the process were the dominant factors there.

STEVE PASTOR: Thank you, Niall. Can I add a quick comment on that? This is a buzzword I picked up from Niall some time back. That concentrated attention that we are now able to give to Trinidad and Tobago and the Gulf of Mexico allows us to do that 'plate to pore' work and really become the 'basinmasters', if you will, from the perspective of geologic understanding, much more so than we were able to do when we had our attention spread out across the world.

DUNCAN SIMMONDS, BANK OF AMERICA MERRILL LYNCH: The first question I have is just about Bass Strait. I wonder whether you could walk us through the opportunity for volumes or prices in gas as these LNG players seem to be on low on their own reserves. Second, related to that asset and probably a little more broadly, what do you think the rationalisation potential for older oil assets is within that?

Second, on exploration, in very simple terms for another finance guy, how should we think about the size and volume of Green Canyon? Is it likely to be a standalone project or is it tied to Shenzi?

GERALDINE SLATTERY: If I got your question correctly, I think you are querying two things: one, the future resource potential from Bass Strait; and two, the rationalisation of the oil assets. Let me talk to the first one. In the presentation, much of our remaining resource potential is concentrated in three places, and Bass Strait is one of those. Within the five-year outlook, much of that programme wedge is, indeed, high CO2 gas in the recently developed Kipper and Turrum fields. We also see future development potential both within and beyond the five years from the high-CO2 reservoirs, West Barracouta being one, and there are several more. We expect to see the Bass Strait gas plateau extending well into the next decade, and there is a multitude of smaller accumulations that are either in the five-year plan or beyond that.

In terms of the rationalisation of the Bass Strait, in its heyday Bass Strait produced about half a million barrels of oil a day. That has passed us now and you will, no doubt, have seen in the press that the joint venture targeting the divestment of the aged oil-producing fields or facilities represents just 10% of the current production. While those assets continue to hold some upside and value, we and our JV partner, Esso Australia, do not think that they are strategic fit for us, and we think that there may be more value in the hands of us, hence the targeted divestment there.

NIALL MCCORMACK: In the area in the two basins north of Shenzi, what we are looking for there are opportunities that have the ability to be standalone; however, there is a lot of infrastructure in the area and there is material ullage in those facilities. That means that, in even in quite large cases, it may be more fiscally attractive to bring it back through the ullage in that system, but not necessarily Shenzi, so I would not think about it purely in that way. That is part of the attraction of the area: you can get things online potentially more quickly and maximise their value through what are multiple different export routes within that area rather than just being dependent on a big new facility. You get to quite large numbers before you need a new facility in that area to drive value.

STEVE PASTOR: It is not either/or; it could be both. It could be production through a tieback, taking advantage of existing ullage and, if it is large enough and warrants an additional new floating facility, that could be an outcome as well.

PAUL YOUNG, DEUTSCHE BANK: First, on Scarborough, you mentioned the potential to tie some resources back into North West Shelf. You have sold 50% of your stake in Scarborough to Woodside. Is the concept there to stay a tie-in into North West Shelf? A year or two ago, you were looking at floating LNG. There was also the comment about being a potential aggregator within that geographic area – could you talk about that?

GERALDINE SLATTERY: Scarborough is a material gas resource off Western Australia. We are currently targeting the sale – it is not yet approved but we anticipate that it will – to Woodside. We continue to have very confident prospects for the development of Scarborough. It currently has two development options being considered very seriously: either a floating LNG facility or a tieback to one of the existing LNG facilities. That is one of the great things about Scarborough: it does have development-concept optionality. Both concepts are currently being studied, so it is too early to have concluded on either one of those. We think Woodside will bring a lot of value to the JV both in terms of their LNG experience but also their deepwater-operating experience. Together with the operator, Exxon, we think we have the right mix to identify the most value-adding development concept in Scarborough.

STEVE PASTOR: I would reemphasise that last point: that we could not be more pleased with the partnership that we have there, because of the strength of the operator, ExxonMobil, and the long, deep, solid performance history that Woodside has in both Western Australia and in LNG. We think we have the perfect partnership mix.

PAUL YOUNG: My second question is on organic opportunities. You certainly have a lot of those, and some pretty exciting exploration potential. You have not even touched on the Scimitar mini-basin and the drilling there. A lot of these projects, of course, notwithstanding the fact that they are pretty exciting, are reasonably long-dated, with eight-to-10-year development timeframes. There are some inorganic opportunities out there, and we have seen some. I am just curious about one of the recent ones, which was Anadarko's purchase of stakes in Freeport's assets in the Green Canyon area. Did you take a look at those assets to potentially look at backfilling the next five years of production at least?

STEVE PASTOR: I think the question may have been more focused on the second part than the first, but you may have a comment to make about Scimitar first and then I will talk about the inorganic.

NIALL MCCORMACK: Scimitar is planned to be drilled after Wildling. It is a similar play concept but it is independent of Wildling, so Wildling's success or failure really does not give us any of that negative or positive feedback that we were talking about earlier. It is, however, a similar play type in the same area. There is probably not a lot more that I could say about that at the moment; it still has some level of commercial sensitivity associated with it.

STEVE PASTOR: To the latter question, Paul, I would say that, in its most generic sense, it has to be the right strategic fit for us and to have a value-accretive proposition for us. To that end, we certainly were aware of and evaluated the Freeport-McMoRan Gulf of Mexico assets and did give very significant consideration there. What I would say about what turned out to be the case there and Anadarko's acquisition is that one could argue that Anadarko is the natural operator of those assets. A lot of the value in that divestment – or acquisition, in Anadarko's case – came from assets that Anadarko were already in and that we, by the way, were not in. When we looked at the strategic fit in particular, there is a difference in our perspective on that versus what Anadarko's perspective was.

JAMES GURRY, CREDIT SUISSE: Following on from that, can you talk more about how acquisitions might interact with the exploration efforts? If you are the knowledge master of a particular basin, surely that gives you an edge on areas that you do not currently have but might look at. Could that accelerate that 11-year timeline that you envisage for success for production?

STEVE PASTOR: As you will appreciate, you could break that down one level and ask, 'Are we talking about pure exploration acreage acquisition or about discovered but not developed, or are we talking about developed?' You get the whole range there, and I would say that we have been quite active and successful in the front end of that. The best example may be the Paleogene play, where we have amassed over 100 blocs over the last year in a trade with Chevron and an acquisition from Conoco. It was a very low-cost way to enter that and very strategically well-aligned with the fact that we believe that our knowledge of the basin is very prospective for Tier 1 oil in the western Gulf of Mexico.

In a discovered-resource sense, we look at a number of things that fit our strategic criteria. One of the best examples is our interest in Trion, where we have confidence in the geology and in the economic potential, although the fiscal terms are not absolutely nailed down just yet, nor are some of the JV-related aspects such as partnering relations, who is to operate and at what equity interest. Those things are all quite important to us. In addition to just the pure growth value case, is it material to us? Are we comfortable with our position as either an operator, which we prefer – and we think that we have demonstrated competitive advantage in being the operator in that arena – or would we be comfortable entering as a non-operator there? Do we see running room to gain a material position and something that is attractive to us in the long run? Those are the things that we think about. At the end of the day, what is the value case? What is the value equation across a range of possibilities? That is how we think about a discovered resource such as Trion.

The last thing that I would say with regard to acquisition opportunities of producing resources is that we do not tend to see the greatest value-creation potential for us from that. Those tend to be relatively fully valued and do not benefit from what we think is our competitive advantage in developing the resource.

MYLES ALLSOP, UBS: To be clear on the big exploration projects first of all, pretty much everyone in this room will have zero value in their model for pretty much all of those projects. In terms of the timeline, when can we start getting a bit more excited about these projects? You are spending a heck of a lot of money on them every year, and we are still waiting for the next big discovery and the potential. Is this five years or 10 years down the line, or can we get better visibility on this over the next two to three years, which I suspect is the average kind of patience that investors have?

NIALL MCCORMACK: That is a very good question and a very fair one, because people have a tendency to have off every well and expect a big announcement one way or another after each one. In reality, however, it is about a two-year time horizon that it takes. Shenzi North is a very good example of that. Before we are going to say anything material, it will have been three wells. You will know whether we are still in the game but in terms of what that means to us, the minimum that you are going to see is three wells. If you look at Shenzi as a proxy for that, seven wells were appraised before Shenzi was fully appraised. It was way down the path before we were at the point where we would talk about what we considered the resources to really be in that area. That two-to-three-year timeframe is not a bad way of thinking about it, and it is certainly not something you should be hanging your hat on for every well, saying, ‘They are in’ or ‘They are out’; it is very much positive or negative feedback rather than an on/off switch.

MYLES ALLSOP: Is that two to three years on each basin?

NIALL MCCORMACK: Yes, but if you look at what we are doing in the activity base, it will be on a shorter timeline in the Green Canyon area and in that range in the Trinidad area. In the Western Gulf of Mexico, we are not getting out there until 2018, so it will be a little further out on the cycle in terms of that.

MYLES ALLSOP: Is it, then, a 2018-19 story?

NIALL MCCORMACK: Yes, the Western Gulf of Mexico will be a little later in that space.

STEVE PASTOR: I want to just reaffirm that we are maintaining a very healthy pull to the left: a desire to accelerate those programmes to see what we have, without compromising quality. I think we have demonstrated that by picking up a second rig earlier this calendar year to accelerate the testing north of Shenzi and the well that we are progressing in Trinidad and Tobago. That is really important to us. You heard both Niall and Geraldine talk about the things that we are doing to accelerate the entire cycle time to first production, and I would say, not to go too far here, that, in terms of the productivity that we have seen in drilling onshore shale wells, we will be back in front of you in two or three years’ time talking about that productivity, meaning it is not 11 years in full cycle, and we have taken material amounts off that. I can say, from having had experience over 16 of my almost 28 years in oil and gas in deepwater developments, that we have opportunity to beat what these guys are showing. I really believe that, and we are going to go and chase that really hard.

MYLES ALLSOP: A second question around the 1P reserves. For many years it was pretty stable over 10 years on the Conventional side, and over the last three years we have seen it tail off or tail down quite significantly. I do not know how worried we should be about that, if reserves are below seven years or so now.

STEVE PASTOR: Let me give you a quick comment on that, and then I’ll offer if Alex or Michelle has anything to add. The history of, and the reasons for, proved reserve changes are different in Conventional and US Onshore. In Conventional, our proved reserves have been rock solid steady, and relatively are a high proportion of our 2P probable reserve. We have very mature fields there that are easier to geologically model with high confidence. I think your question really relates more to the changes in Onshore proved reserves, because Conventional proved reserves have not changed very much at all, other than just decline rate.

In onshore – Alex, please.

ALEX ARCHILA: It is mainly a price issue for the proved reserves. You take the SEC price and you apply it; that is an end of year calculation, 12 months backwards. If I have my numbers right, the year before we had 77 or something like that, and in the following year 42. What I would invite you to work on your models is, if you have a view of prices, in a way you can forecast what the trend could be on a passback.

STEVE PASTOR: To be clear, it is a bit mechanical, but the definition of SEC proved reserves has certain requirements. It is formulaic, and it requires you to use backward looking 12–month average prices. When we come upon our proved reserve estimates, and look back over the last 12, clearly that is not our expectation going forward, but it is the basis for our proved reserves determination that has had a material negative impact in this past year.

GERALDINE SLATTERY: The manner in which the SEC rules work in Shale is calculated on a per well basis, whereas in Conventional it is calculated that the project is the field, where you have a smaller number of wells but the overall field is what dictates the inclusion or otherwise. You also have the inclusion in your development plan within the period. I think in Shale you would expect to see the 1P reserves number going up and down as prices change, in contrast to the Conventional, of course, which stays pretty solid, aside from projects coming in and production coming off.

STEVE PASTOR: Thank you very much. We have time for one more question. We are over by a bit, and out of appreciation for those of you who have stayed on the webcast and telecoms as long as you have, and are probably in a part of the world where it may be the middle of the night, I will offer that last question to those remotely connected.

OPERATOR: We have no further questions on the telephone line.

STEVE PASTOR: Congratulations.

SYLVAIN BRUNET, EXANE BNP PARIBAS: Just following up on your comments, Steve, that overall you would prefer to be an operator. At the moment, really, on the conventional side it is really Shenzi and Neptune. Do you have a target in mind – I know these things tend to be opportunity – of where you would like to be? Related to that, what are the benefits you see, or alternatively what you feel you miss, when you do not operate, in terms of focus on costs and so on? Clearly, coming from a mining group, the focus on cost has been a bit easier in the culture than among your peers on the oil side. Is that a fair comment?

STEVE PASTOR: It is. It is pretty straightforward. Firstly, I would just say that the joint venture partnering or joint venture relationships that we have, and the assets that we are part of across petroleum – even in a non op position – we have great relationships with our partners, and we love those assets. That is true whether it is the legacy assets in the Bass Strait and the North West Shelf, or the fantastic assets that we have in the Gulf of Mexico with BP. Our preference to operate comes from our data driven, historically proven competitive advantage, we think, in generating superior value in the arenas where we work.

Further to that, it depends on the joint venture operating agreement, but having a relatively greater influence and control over the pace and the ultimate direction that a programme goes in. Again, it depends very much on the uniqueness of a joint venture operating agreement.

10. Closing remarks

Thank you everyone, and let us go to close. I have a few final comments. I want to thank you again, particularly for the great engagement that we have had today. I want to close reinforcing the key messages about Petroleum. Petroleum is absolutely a core part of, and a good fit with, the overall BHP Billiton group. We have great assets, strong operational performance, and with a backdrop of strengthening markets, we think it provides options to deliver significant value from our existing portfolio. From both Shale and Conventional, in the near term, through an exciting exploration programme, we are testing plays that can significantly grow our resources and value.

Finally, petroleum opportunities, at the end of the day, must effectively compete for capital. Our operating model, as well as our disciplined capital allocation framework, will help to ensure that we make the most effective, timely, and valuable decisions for our shareholders. Thank you again for your time today. We really enjoyed meeting with you, both during the programme and during the break. I will look forward to continuing to receive your questions over lunch and in the coming days. I hope you have learned something and got something from your time today.

I also want to close by thanking the Petroleum Leadership Team, who invested their time and energy, and I think did a fantastic job today presenting our outlook for the Petroleum business, as well as the vast support that we get from Investor Relations and everyone else what has put this programme together. Thank you very much, and we will close here.