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Peter Botten: Ladies and gentlemen, thanks very much for attending our shareholder briefing investor briefing this morning. It's great to see the number turn up and obviously you're not here for the sandwiches afterwards clearly, but at the end of the day it's great to see the numbers both here physically and I know through the web. So thank you for attending. A little bit of housekeeping, there are no fire exercise alarms planned for this morning, so in the event that you do hear a whoop whoop whoop in the normal way that fire alarms do, the main exit out onto the street is actually the hidden door underneath the green screen at the back. So that's the easiest and safest way out in the event that we have to terminate this because of safety. Toilets both male and female are downstairs I'm sure, you may or may not need that during the break that we have coming up in the session.

The presentation that we want to go through with you today, I'm going to give a bit of an introduction and where we see strategy and where the company's heading both in PNG and also now obviously Alaska. We're really pleased to have with us Bill Armstrong from Armstrong Oil and Gas; it's great that Bill's come out from Denver and all points in the US to actually give you his views of life. Bill is a really nice guy and it's great that he's here and shared some time, so thanks Bill for coming out and being with us and giving the opportunity for investors to hear what you think and also answer I'm sure some questions during the course of the morning.

We then will turn it over to Keiran Wulff, who's our EGM of exploration and new business, and he'll spend some time walking you through some of the technical aspects, deal summary and some of the key and important issues in Alaska that we feel are important to communicate to our investors, the exploration upside and also after the break the development plans, some stakeholder engagement issues and some of the programs that we see moving forward. At the end of the exploration upside there'll be a short period of time for Q&A. Again, at the end of the Alaskan exercise after the program's scheduled summary we'll also have some Q&A's on Alaska. I'll come back to talk about LNG expansion and give you an update on that.

Chelsea McGregor, who's our Group Treasurer is very ably filling in for our CFO who is in hospital this morning having some surgery. Nothing major we understand but Chelsea will fill us all in on the financial overview, and then again, we'll have another Q&A session. So that's broadly speaking what we're going to go through today and this morning and it's a real pleasure to be able to pass this information across to you.

I suppose first off, a little bit of an update on our strategy and where we're going with respect to our business in both PNG and now Alaska. The most important thing in PNG as we all know is that we have an enormous and strong resource base. It's dominated by gas but the reserves base that we have in PNG is significant and with the work that's gone on over the last couple of years in terms of optimising our portfolio there and looking at ways of where the gas may be, and it is gas dominated, we have a number of commercialisation options to bring some of this gas into a commercial reality.

At the moment, we've dedicated 10 tcf of proven and probably resource dedicated to LNG expansion and the development of Papua LNG. So a significant volume of gas is part of the next phase bringing on two more trains, and I'll speak about that later. Two train expansion can and will be delivered, it's moving forward at a pace and I'll update you where we're at with that later on this morning. Appraisal and exploration success over the next few years will inevitably deliver significantly more gas. However, the reality we all know about LNG projects and brought to me in spades by meetings I've been to in the last few weeks and again on Tuesday, indicates that LNG projects are complicated. They require strong participant alignment and they require strong market support and financing. Unbelievable projects when they're getting up and PNG LNG has got up really, really well, but they are significantly complicated beasts and that means it does take time to bring to market.

I suppose one of the challenges that we have is that we're not in full control of that process and it does require time to commercialise. In reality from FID decision on trains one and two to FID decisions on train three and four will be 10 years. A strategic question for us is whether there'll be another 10 years before there's a further two trains come to market. That's a question that strategically we need to answer. There is a very strong need to align our interests and align our interests in different parts of Papua New Guinea to actually make the next phase LNG development work. I'm moving past trains two and three, three and four now into five and six and beyond. In reality we have resources spread across the whole country, at least in the Papuan Basin.

In the North West corner there's a very strong alignment between PNG LNG partners in terms, led by ExxonMobil, Oil Search, Santos, Government and the Japanese. A very strong alignment about what can and should be done in that area. Clearly a part of the expansion will involve commitment of further resources from PNG LNG, whether that be in Hides, the oil fields, P'nyang et cetera to underscore the next phase of commercialisation. But in the North West corner we have constraints around infrastructure and with one train coming out of PNG LNG our infrastructure from the Highlands will need to be modified in the event further gas is found.

So in reality a strong alignment in the area around Hides and between Hides to Muruk to P'nyang there certainly is the potential to have in the order of 10 to 12 tcf of new discovered resource. The question is how does that come to the market? If we move down to the Elk-Antelope area there is alignment and growing alignment between ourselves, Total and Exxon, and aligning both exploration and development interests in the onshore and offshore Gulf remains a key part of where we go. Certainly, again we believe there are a number of Elk-Antelope lookalikes available to be found in the Gulf onshore. The offshore [low] not well tested, especially the deep water certainly has multiple tcf potential.

The question is when and how do we invest as at Oil Search? We do not want to invest substantial funds in wells like Muruk unless we see a clear path to commercialisation. Muruk is a $200 million well plus side tracks, we need to see, and as part of our overall strategic analysis, understand how we bring gas to market. That is a question about balancing where we spend our money, whether it be in the Gulf, onshore or offshore or in the highlands or a combination of both. But we as a company need to fully understand what the strategic imperative is and our road to commercialisation for our large gas resources. That's clearly a focus for us in the first part of 2018 as we align ourselves for the development of the next two trains, what about the further trains and where do we go to ensure we get timely commercialisation of what is an enormous resource-base that we see presently available and to be found in Papua New Guinea.

All of that leads to a very disciplined capital prioritisation and it does mean that we have to work very closely and align ourselves with our key partners in Gulf certainly as well as obviously in the PNG LNG related areas in the North West. Just to highlight that, our analysis in terms of yet to find, 92% of the gas, of the resource base remaining in Papua New Guinea is gas, 92%, and discoveries to date indicate we've got 12 developed fields, 30 undeveloped fields with 24 tcf of gas already discovered yet not commercialised in Papua New Guinea, 24 tcf of 2C resources waiting for a commercial home.

So the obvious question is how do we bring that to market without overcapitalising, optimising our capital spend and placing ourselves in the best possible position to drive the maximum value? We see P50 discoveries I say around 24 tcf but yet to find another 40 tcf, pretty evenly spread between the Highlands, the Gulf onshore and the gulf offshore. Again, if we want to husband our money well and get good return on that money we need to understand and have a picture, not just Oil Search but a picture for Oil Search with its key partners in different areas a plan to commercialise. It's a significant resource base absolutely, but being gas and being LNG requires some coordination and that's part of our strategic process that we'll be going through to clarify with our partners and develop a vision for trains five, six and beyond past trains three and four.

The strategic rationale therefore for Alaska involves a clear focus on being able to control our destiny and removing some of the barriers to commercialise a resource base. We believe Alaska brings a sustained predictable development for Oil Search into the future and gives us an element of control with our joint venture partners that we can bring this tier one resource to market quickly. We do believe it is a tier one resource and it has significant upside in development and exploration potential beyond what we paid for this asset. We think the entry price was compelling and we did it at the right time in the development cycle, appraisal cycle and the right time in the oil price cycle. We see a conservative resource development assumptions going in and will discuss those later on, and Keiran and Bill will discuss that along with the financial issues provided by Chelsea.

The deal structure we have for entry into Alaska provides significant optionality and risk mitigation for oil search and it allows us to have an option to partner with key strategic players that confer the dry value to our business. We do have an opportunity to drive early commercialisation, it significantly enhances our resource position and reserve replacement opportunities and enhances our shareholder returns in a post 2023 period. With no change to dividend policy between now and then and supported by a very strong balance sheet with good flexibility to allow us to manage the significant investments that we must make on LNG and now Alaska development over the next four to five years.

This diagram summarises both PNG and Alaska together. You can see in the top left-hand corner a view of how we can significantly improve and deliver high quality tier one production from both PNG LNG, PNG LNG expansion and Papua LNG along with a base case or at least a phase one oil case out of the Pikka in Alaska. It's a significant development and significant add to our production base in what is two tier one assets. I don't believe there's any oil and gas company of our market capitalisation with this quality of resource base and the opportunity to double our production in these types of assets.

If you look at the exploration and production acreage position in the top right slide you can see that Alaska's footprint is extremely small versus that of PNG. Yet if you move to the net prospective resource base you can see Alaska has huge running room, huge running room over and above despite the size and shape of our licence portfolio. We're assuming at the moment a base number, which Keiran will talk about, but there is substantial further upside in our licences in Alaska, despite our relatively small pool of licences that we have there.

So if you compare I suppose the asset base we have with two trains moving forward to LNG expansion and development of Papua LNG with long-term gas business and optimised development of the large gas resource in PNG, combined with a direct to market oil business, we have an unprecedented set of assets in our view that we can manage and develop over the next five years and deliver substantial shareholder return post that with further growth in both the gas and oil business. Now I won't highlight this too much but we have been looking for these types of assets for quite a while and signal that as part of our overall business balancing out our portfolio. I suppose it may be the little difference between what we're trying to do in terms of understanding and growing our business in gas but also recognising that LNG projects are difficult to market, complex in nature. We've done it before and we'll do it again but highlighting and Oil Search perspective that really can deliver faster to market oil in a top tier one resource through our Alaska asset.

With that introduction I'll throw it over to Bill, who can give his perspective on the Alaskan oil slope and give some background I'm sure on how the transaction came together. So welcome, Bill, welcome to the stage and the floor is yours.

Bill Armstrong: Hi everybody. I'm a private guy, a private company, so standing here in front of 70 analysts is not my thing. I'd rather be that CFO getting an operation right now than doing this. But Keiran and Peter wanted me to come here and give you my perspective. Alaska, a little bit of background, how we found it, how I found Oil Search, where I think it's going, where's it been, et cetera. This is Oil Search's show today so when Keiran showed me the slides I had it was really lame compared to - because all the slides that he has are my slides, which really pisses me off. I found this baby and now he's raising it and that's difficult for me.

Anyway, am I in charge of the slides or is somebody else? Oh [expletive] what did I just do there? Okay, here we go, thanks. Obviously, I'm not good at this. Let's talk a little bit about Alaska, a little bit how I found there. So my company is private, I grew up in the oil patch in West Texas, been on my own since I was 24 years old, I'm 57 now so I'm 33 years of doing my own thing. Started as a one-man company in the attic of my garage, Apple's got nothing on me, they started in a garage, I was actually in the attic of the garage. I'm a geologist by training, I met my wife the first day of class in Geology 101 as a freshman in college, and that was the best trade I ever made was getting her. My business model has always been to pursue company impact wildcat exploration which is extremely unpopular today in the United States because everybody and their brother is drinking the unconventional shale Kool-Aid.

But over the years I got really good at finding oil and gas, I found production in a bunch of states; California, Michigan, North Dakota, Utah, Wyoming, blah-blah. Anyway, somewhere along the way sort of assembling a bunch of really talented guys that I met while I was pitching a deal. Everybody has their skills, I think my skill best of all is probably looking across the table and looking in a guy's eye and realising does this guy get it or not? Because if you saw my employees you would really clearly recognise that I don't hire for personality or looks, hopefully they're not listening to this today. But somebody who can find oil and gas is a rare type and in all of my guys have what I refer to as the FTR, which translates to Your [expletive] Track Record. Can you say that here? No F-bombs? Your Fricking Track Record.

So all of my guys that work for me are unbelievably talented to find oil and gas, most of them are major trained, a lot of them are Exxon trained. Anyway around 2001 I hear of this opportunity in Alaska and I decided to go have a looky-loo to see if that made any kind of sense. I've never been confined to an area, I've always felt like you need to look at all kind of areas to figure out what's the best to go because how would you know if you're in the right area if all your work is the Permian Basin or all your work is Louisiana or the Gulf of Mexico or deep water or something. So I always looked around, so I went up to Alaska in 2001 and I saw this awesome incredibly rich petroleum system that was in the US terms was like the Mecca of oil fields. Because everybody always talked about Prudhoe Bay. I mean Prudhoe Bay's the largest field in the United States by a factor of five, or three I suppose of the second biggest field.

Everybody talked about North Slope in hushed tones. If you look at this map here - this is impossible to use - there's Prudhoe Bay off here to the east and that was found in 1968, it was turned on in 1979 and you can see that it started off at about a million and a half barrels a day, rapidly peaked at about two million barrels a day and then it's been on a relentless decline like all big fields do ever since basically the early '90s. Alaska has that gigantic field, the source rocks of Alaska are unbelievably rich and unbelievably prolific, the three main [horse] rocks have generated and expulsed about 1.5 trillion barrels of oil. If you add up all the fields in Alaska just a very, very tiny fraction of that 1.5 trillion barrels has been found. So as an explorer you have to ask yourself well where's the rest of it.

So you have the Prudhoe Bay field at 13 billion barrels and there's another two dozen fields that are 100 million barrels, so they're really, really good fields. Multiple-billion-barrel fields, this field here, this oh my god, hang on, this is a touchy little [expletive] this guy isn't it. So this here is Kuparak River field, it's about a three and a half billion barrel field, this is a field over here by ConocoPhillips, it's called Alpine and if you add all its little satellites up it's about a billion barrels. Anyway, so I came out here and decided man-oh-man this is like nobody plays Alaska. You've got Exxon, you've got BP and you've got ARCO which eventually became ConocoPhillips, and yet there's nobody else. So they dominated the infrastructure and they dominated the politics and it was their world and I was a latecomer to that game. I came out here in 2001 I thought this is - there's so much grass on this playing field I could not believe it. So I started putting together deals.

There's a field here called Quguruk Field, which me and a partner out of Texas discovered, I believe it was in 2003, it was about 225 million to 250-million-barrel field. The very next year I brought in a company out of Oklahoma City called Kerr-McGee where we found this field here called Nikaitchuq, it's about a 300-million-barrel field. Two years after finding those two fields I was in a non-opposition with 30% interest and I got hit with an AFE which I couldn't cover, so I had to sell my position and I was in a squeeze. I had to bring in a partner so I sold my position to a company called Eni, out of Italy. I'm sure you guys have all heard of them, big major oil company. So I took a few years off, came down to the lower 48 and decided what I wanted to do there and I looked at all these crazy Shell plays that everybody was making, very difficult plays to make money despite what they say. Great way to find oil, terrible way to make money.

So I came back to Alaska in 2009 and we had learned a lot, we knew what we wanted to chase. We wanted to chase really high-tech AVO/inversion technology anomalies in seismic. Alaska is an interesting place because almost all the fields in Alaska are stratigraphic traps, and it's the exact opposite of Papua New Guinea where you have these big anticlines. In Alaska it's mostly all strat traps and as you all know if you've been studying the oil business, big oil doesn't like chasing strat traps because it's easier to go shoot a whole bunch of seismic, look for a big bump and go drill it. Alaska's a lot more subtle, it's a lot more - it's a little bit more distinct of a typical way to play the game.

So we came out here and I'm 100% comfortable with playing that subtle stratigraphic trap game. So we assembled a bunch of land on some ideas that were pretty easy, they were onshore, they were close to infrastructure and each one of them had size, because out there if you don't have enough size you're going to be at the mercy of the infrastructure players. So you've got to be big enough to build your own infrastructure. So we assembled three quarters of a million acres, I brought in a company out of Spain by the name of Repsol, as my partner, they have been an absolutely terrific partner for me. So over the last five years we have started this exploratory game we've done together. In that, since 2011 which I brought out Repsol we've drilled 19 wells, we've had 19 discoveries and we've just crushed the ball.

About three years ago, four years ago we drilled this well called the Q3 well, which is just to the east of Alpine Field, right here, between Alpine Field and Kuparak River Field. I found a tonne of oil and gas in my life but when we saw the Q3 log I knew for the first time that we had really, really outkicked our coverage. Does that translate into Aussie football, kicked your coverage, you don't know what that means? Whatever, it was bigger than we expected, how about that? We followed that up the next year with a five mile step out to the north extending the field. We then stepped out three or four miles to the south west the next year and extended it again and it's everything you want on a field, everything. It's shallow, it's regular rock, it's 24% porosity with good permeability. It's high gravity oil, it's sweet oil, it's not gas, it's just everything you want, it's just fantastic.

So this last - I guess it was two years ago now, we dialled in our seismic to what we were looking for and once you knew what you were looking for it was kind of hard to see before you drill it, but once you drilled through it and you had a sonic log and you were able to really figure it out, suddenly it was a little bit like balls on a dog and - does that translate in this country too? I just want to make sure you're still alive. We stepped out and drilled an extension. So in the United States when you drill an extension well everybody brags about it, if you go in the Gulf of Mexico they'll say, oh well, we had a big old step out this year, we just drilled a one mile step out through our discovery in the blah-blah-blah deep-water field, you know what ever. A mile is a big way to go. This year we stepped out 21 miles, 21 miles and we drilled the Horseshoe well and we found the exact same field way down here, and these are all connected between the two.

The seismic is all shot with 3D, it's the same sand, it's the same oil water contact, it's the same oil, it's everything was the same. Not only have I never stepped out 21 miles and extended the field but I've never read about somebody that stepped out 21 miles. So we suddenly in our office realised that - there's a real famous movie called *Jaws*, and Roy Scheider saw that shark for the first time and he says we need a bigger boat, and that's exactly what I realised I needed was a bigger boat. Occasionally in life things go really, really well for you and in this case, it did for us. Sometimes it's not 100% perfect and when we found that field is when the price of oil collapsed. So who would have ever thunk that we would get a field this big at the same time the price of oil collapsed? That's just life. I mean think about how hard this was guys, the last time a field was found this big in the United States was 1968, that was in Prudhoe Bay.

You're going to see some numbers here, I'm probably talking off script, Keiran, are you okay with this? I don't know, okay. You're going to see some really lame numbers from these guys today because they're confined by the SEC and their dweeb engineers and other stuff, that doesn't give them the credit of what you deserve. But you guys can do the math, you can pull your calculator out and you can see 40 miles long by two and a half miles wide with about 120 feet of average pay at 640 acres per section. Multiply that by about a 325 barrels per acre foot and you can see that's about a three billion barrel field. You're going to hear some numbers today that are substantially less than that so I probably shouldn't have said all that but that's the truth. So when Oil Search is going to be talking about half a billion barrels or something, they're talking about where we just actually have just dead solid, look over your fence and they don't give you credit beyond the fence but your well's right there and your well's right there and the well's right there. But we can tell from our seismic and our step outs that this thing goes a big long way.

So that's all really, really exciting stuff. I was caught in what I unaffectionately refer to as the duck breast, and that is I had a partner in Repsol who wanted to go fast, fast, fast. I had a State of Alaska that wanted to go fast, fast, fast, and it was a big-time game and it cost a lot of money and so I had to raise a white flag. I had a lot of options to go with as far as what I was going to do with this position. I could raise a bunch of private equity money, but I have one boss right now and I sleep with her, and the last thing I needed was another boss, another private equity guys. So I kissed a lot of frogs and talked to a bunch of guys like the guys at [Pickett Orberg] and Blackstone and NPG and all the guys. Then I had most of you guys are bankers, right? I think I talked to a lot of you guys - all of you guys wanted to take me public. Can you imagine me being a public officer saying all this [expletive]. I mean that's not going to happen.

So I had [Cresswess] and Goldman and UBS and Morgan and all the usual suspects trying to convince me I wanted to be public. That just sounds like a root canal and an enema operation at the same time. So I like being private, I like being the explorer, I don't really want to be the guy who's doing all the development. So I hung out a shingle I guess for lack of the term, to talk to some players about buying this. Believe it or not, my relationship with Oil Search goes back a long, long way. In fact, one of my top technical guys was one of the lead technical guys who found the discovery of Hides Field way back in what was that, the late '90s I guess it was - yeah. So when I stole him from Exxon he tells me all about the Hides and the Kutubu and the Moran and all the fields you guys had in Papua New Guinea.

So part of my job is to find out where I should go next and so I follow the world and I follow who's the best explorers, and Oil Search is really in a league of their own. I mean we could talk about Lundin finding Johan Sverdrup or we can talk about what Tullow does in the mid African rift or you can talk about what Kosmos does in Mauritania or whatever. I know all these guys, I know all their plays and I know how good people are, and Oil Search really is in that upper league group. About two years ago I was reading about you guys chasing InterOil and chasing the Elk-Antelope Field, and one of my good friends had actually left Canada and gone to work for Oil Search. I was so enthralled by what Eni had just found in Northern Egypt, called Zohr Field which is this big reef play. So I remember emailing at three in the morning. As you get older you just don't sleep like you used to, I don't know why. Do you guys have this problem? You're too young, look at you guys, most of you guys don't even shave yet.

But as you get older you can't sleep as well as you used to so at three in the morning I'm texting my buddy who works for Oil Search and saying hey tell me about Elk-Antelope and how does it relate to Zohr, it's a Miocene reef and it's really cool and blah-blah-blah. We start going back and forth with late night emails and he was of course as friends do say, well ,how you doing ,pal? I said, well, listen, I've got this field out in Alaska that I found that is just like amazing. Who would ever have thunk that a dozen guys in Denver would find the biggest field found in the United States in the last 50 years. I mean if I had gone to Vegas and said I want to take a $100 bet on the fact that we have this 12-man company in Denver and after 50 years of all the oil companies in all of the United States looking for a field to find this, and we're the ones that find it? Vegas wouldn't have given us really odds, it would have been something, it was so out of the plain. So I'm really proud of what we've been able to do, but it was a real long shot and it ended up working.

Anyway, so this gentleman at Oil Search, named Bruce Taylor, and I went back and forth, and he said hey are you familiar with it, we're pursuing this oil initiative, we're mostly an LNG company and we're in Papua New Guinea but we also have this oil initiative. I said I'd kind of heard about that a little bit. So badaboom-badabing I meet with Peter up at CERA last year, at the CERA conference and we ended up sitting next to each other. I was like the guy that spoils the punch at the Christmas party, everyone wants to talk about oil unconventional and I just think that's like flushing money down the toilet. So I just pulled the pin out of the grenade and rolled it in the middle of the room; pandemonium ensued.

It was funny because all the CEOs of all these major oil companies who couldn't say it publicly, all grabbed me after the dinner and said we can't talk about it but we agree with you. So Peter and I struck up a friendship and before you know it we were going back and forth with our asset in Alaska and what they were trying to do at Oil Search. To me it was such an obvious pick for where I wanted my asset to land because I love Alaska and I love what they're doing, the people that do for that state. They don't need another major oil company up there, they've got that, they've got Exxon, they've got Conoco. I wasn't big enough to handle it, it was too big for me and it was something I didn't want to become, I didn't want to be public. This is going to be my last public talk to a bunch of analysts again. So I owe it to my friends in Alaska, I owe it to the native [corporate] Alaska to find the perfect company for the job, and Oil Search is it, because their relationship with what they do with the natives, the Indigenous people of Papua New Guinea is just so spectacular.

In Alaska, we have a very smaller version of that but we have that version. We have the native corp that works up there and they need the respect, they're good people and Oil Search would give them the type of respect and attention that they deserve. They knew that I couldn't handle this, they didn't want me to go to one of the big boys that we were talking to. So before you know it they made me an offer that I accepted. It wasn't a good offer, it was an okay offer, it was a shit load less than I expected but I've got to hand it to the guys at Oil Search, they knew what would not make me happy, would know what would make me do the deal, it's a big difference. So that's the deal we cut, and they're going to talk about all the details about that.

But I'm happy to answer any of you all's questions about anything I just said to you, and more than happy to talk technically, which is I normally do, but also otherwise. So just let me know. I think that's enough, do you want me to keep talking, Keiran? They're giving me the hook.

Peter Botten: Thanks, Bill, for giving us that colourful and insightful view that you have. I must say, and there are lots of questions about why we did this deal or how we did this deal versus other majors, but I can tell you that in the oil and gas space that we work, Bill wasn't particularly happy as he said with our offer, and Bill has a view about the upside and capacity of these assets. But when we actually struck the deal it was when oil prices were a bit lower than they are now. Bill is one of those guys that if he strikes a deal, despite a lot of pressure from other people, and Keiran will talk about that, he actually stuck with us. I don't know very many people that would not have re-shopped as the oil price changed, and I can tell you that's a piece of business that we're appreciative of Bill doing, and I think in this world of greed and avarice generally I'm sure there are very few people that would have stuck with us when the oil price did go. Bill, thank you for that, and on behalf of our shareholders we will convince that Alaska has significant upside as you annunciated. Thank you for that because you are a gentleman and there aren't many of us left.

Keiran Wulff]: Okay indeed, it's a hard act to follow but we'll get into a little bit more mundane things going forward. You can read some of Bill's slides that we didn't go through in the pack a little bit later but I actually want to start off with how did we get into identifying Alaska in the first place. Over the last couple of years, we've taken advantage of the downturn to really consolidate our position in PNG and build for the future so that there's a sustainable business model in PNG where by we've got, as Peter went through, we've got fantastic gas assets but we also have the exploration portfolio to support the gas growth. While we've been doing that we've also been looking at what other deals have been going on globally over the last two years and indeed a long time before that. We have a dedicated team screening opportunities and then looking at the nature of those opportunities and seeing how they would fit in PNG.

Frankly we didn't see anything over the course of the last couple of years that even remotely interested us or remotely compared to what we have in PNG. What we've been doing is that Armstrong as he said had been running a soft process with majors and considering and IPO, and we developed a strong relationship with Bill and I've got to tell you, there was lots of interesting discussions and basketball in their boardroom and a number of other things that led to us developing a relationship.

But what we also recognised is that we also had to have a bottom up approach here that demonstrated the value of this to our own shareholders and that the deal that we did for our shareholders was based on a degree of certainty that really was able to be compared against our quality assets in PNG. One of the things we wanted to do is to definitely under-promise and over-deliver in relation to these assets.

When we went to screening these new opportunities, the new opportunity had to have a material volume with early production. It had to be something that was liquid biased and complementary to PNG so, in other words, it didn't compromise our ability to deliver PNG.

Peter talked about the fact that we don't control the pace of activity in PNG with the LNG projects and that's something that we wanted to do. So, whilst we're quite happy to - things should be based on value - what we wanted to do was to try and focus on an asset where we were able to utilise our operator position and also develop our existing relationships. Already we've developed some [stronger] on the process of developing some strong relationships in Alaska and I think we'll fit there very well.

We also wanted to go into a place that had political stability and fiscal stability and we've actually seen some really positive fiscal upturn just recently with the Trump Government so, hopefully tax initiatives that Chelsea will talk about and whatever we bought had to have upside. When you actually put that screening criteria not many things meet the ball. So, fortunately we did see that in Alaska and as a consequence of that we pursued it.

What did we buy? I won't go through this in great detail but we structured our deal so that - for our shareholders we didn't want to look as though we're betting the farm and we also didn't want a situation where shareholders doubted our voracity or our focus on PNG. So, what we thought we would do is structure an option arrangement with Bill whereby we bought half of his interest upfront and we gave ourselves a 20-month option to buy the balance for an agreed price. What we also had to do during the process here was to identify a price that, as Bill said, met his minimum requirements. It may not have made him happy but certainly something that we felt was a comfortable price that we could justify it to everyone.

The important point here is that when we built our price expectations up we did it on the basis of a bottoms up analysis. We didn't rely on Armstrong or Repsol work - there was a lot of great work that's been done over a number of years - but we had to build a case that we could demonstrate to Bill to show him that there was some rationale behind our valuation. We came up with an acquisition case of around about 500 million barrels. Armstrong and the joint venture's case for the same situation's about 820 million barrels and we think we can potentially get there but through a series of appraisals. So, one of the early stages of the discussion with Bill was quite clearly that this field needs more appraising and we want to pay for what's actually there.

In regard to the option agreement, we think this is a very smart deal for everyone. It provides us an ability to go through and undertake an amount of appraisal and evaluation over the course of the next two drilling seasons and really make a decision exactly before we commit to undertaking that option. But importantly, the option is able to be transferred or on-sold to a third party and we're in a situation here where we intend to create a lot of value, work with Repsol and bring in the right party at the right time.

Peter touched on that Bill had a number of other options and he genuinely did. When Peter and Bill shook hands in Sydney the oil price was low, there was a lot of uncertainty but there were still some major companies who were interested and a couple of those major companies have actually approached us post the announcement with one particular company very actively pursuing us. So, we're pretty confident that we've done a pretty good deal here.

I won't go through this slide. You've seen this in the previous presentation but this gives you a feel of what our equity is across the licences. What we wanted to do is to make sure that Armstrong - they are a fantastic oil explorer and finder and we wanted to make sure through the transaction that they remained committed to the program. So, a big part of the discussions that occurred was how was that achieved? Fundamentally we take them out of the development but their very focus and their quality exploration staff can remain and actually will be integrated into the team.

We've also had a number of a discussions and workshops with Repsol about aligning ourselves there and we're very, very corporately aligned with Repsol in regard to aggressively appraising. We're also appropriately developing and holding discussions, cooperation discussions with the parties next to us, namely ConocoPhillips and others but I'll let you read that one a little bit later.

In terms of the acquisition matrix or metrics, again this is a slide that came out in our original presentation and I just want to re-emphasise that the nature of the transaction - as Peter said, this is a tier one asset in a great location but our acquisition asset based on the value of the acquisition per barrel, based on our acquisition numbers of 500 million barrels gives us about a $3.10 per barrel acquisition on a 2C Oil Search estimated case. That's based upon our acquisition case. If we're able to achieve the Repsol estimate that they publicly announced in their press releases at about 1.2 billion barrels and there's certainly potential to get there, this will be one of the lowest, if not the lowest acquisition done on a dollar per barrel basis done in the last 10 years. So again, we don't think we've overpaid. We've built this bottom up and we're very confident about being able to deliver this for our shareholders.

I want to just touch on - again, this is a slide that a lot of people when we first went out said this was a great slide because it put into perspective PNG versus Alaska. A lot of the questions that come out is how are you going to operate in Alaska, what are the synergies, why Alaska? Well, frankly there are a lot of similarities between PNG and Alaska. The geology is not too dissimilar. You've got a Fold Belt and a Foreland Basin, the age of the source rocks, the age of the reservoirs is identical. In regard to the operations, the operations in Alaska were all about planning logistics and seasonal activities, something that Oil Search is fantastic at in regard to operating in PNG. Again, seasonal, planning and logistics.

The big difference between Alaska and PNG is that in Alaska there's a substantial operating base and infrastructure in and around Bill's assets. Bill did a fantastic job in the fact that he aggregated a number of assets that were surrounded and squeezed between 2.- billion-barrel Kuparuk field and a nearly billion-barrel Alpine field so, the area's actually transcended by a number of pipelines and roads. Gravel roads go fairly close to the operation. A number of us have been up there. We've looked at the logistics and we've looked at the operating capability and with our relationship with Halliburton and also the relationship we're building with local contractors, we're very confident, in fact we're very confident of being able to do a very good job up there.

So, getting into the asset specifically. One of the - [Anne] wanted me to show you this in terms of what was the chronology of the development of the knowledge base in Alaska. The map on the right - and I'm a little bit like Bill - the map on the right shows the wells that were drilled by Armstrong over a period of time. You'll see that Armstrong really came back and entered Alaska in 2001, had a lot of success bringing in ENI, Anadarko and Pioneer in. They rapidly got some of these developments on stream so, by 2008 and 2009 you already saw a significant contribution.

It's interesting to attend a lot of meets which we have had with the government, with the community, with contractors and Bill is very, very well-known by all and sundry and he's seen to be a major catalyst for activity in Alaska.

What we've got here is we've had a country which has had major or recently has had major acquisitions or major discoveries, the majors are focused on developing those discoveries and they've not really focused on the seasonal exploration and Bill's come in and filled that niche. What we saw there is that early discovery sold, went away, came back in 2009, bought in Repsol for a substantial carry, Repsol operated this and drilled a number of wells, acquired a 3D seismic and it was during this period where we actually saw the Nanushuk discovery. ConocoPhillips followed it up with

Willow, as you would see. ConocoPhillips are actually drilling two appraisal wells or two exploration wells appraising this season and as you saw, Bill finished it off with the Armstrong operated Horseshoe well in 2017.

So, it's been a continual progress and significant contribution to the Alaskan oil industry by Armstrong Oil and Gas.

Just quickly, this is jumping in early but I just want to show you just why we were excited when we looked at this. A number of us have backgrounds in sequence stratigraphy. This is the Q3 Discovery well and Q3 was a 2000 foot lateral and effectively what they did, they did a six-stage fracking on the lateral through this reservoir sequence here and they had a peak rate of about 4600 barrels a day at 30 API. They followed up with a vertical well and Qugurk which is a number of kilometres away, I think about five kilometres away. They tested a five-foot zone in the poorer reservoir quality, deeper so, this is the gamma ratio in the reservoir section. They've followed that up. There was no stimulation and they got a 2100 barrel a day 30-degree API with good recovery.

What they did and they did it very well, they tested the productivity of the reservoir early through both a lateral and a vertical and quite clearly when you're going to develop this field, you're going to do it with a series of laterals. I'll talk about that in more detail.

I'm not going to go through this slide in a huge amount of detail but this is the - what Armstrong and Repsol did, they concentrated the drilling activity in the northern area. This is the Alpine field, as I said, which is ConocoPhillips. Their processing facility's sitting here. This year, ConocoPhillips are planning two wells. They're planning the Putu well here which is immediately adjacent to the boundary and the Stony Hill well down here between - which is close to Horseshoe. What they're doing is they're evaluating the extent of the field in their areas. This will be - whilst the current development plan calls for separate facilities and everything else, what likely should happen and what we'll be having discussing with ConocoPhillips is how do we cooperate with ConocoPhillips to minimise development costs and actually maximise production?

This slide here on the right gives you a feel for the size of the size of the scale of the oil column and it's a very, very clear continuous zero ambiguity of the connectivity of this reservoir over a large section. The Horseshoe data which was drilled by Armstrong in 2017 sits down here. The Qugurk wells sit up here so it's a very, very clear continuous oil column through the entire 650 feet of oil that's been identified in the wells. As Bill said, he's drilled 19 wells which are 12 vertical wells and seven side tracks. This is a very well constrained field with a number of 3D seismics over it as well.

The big question also, what everyone says is how was it missed, the majors with their - there were a number of reasons why it was missed. The primary reason is the majors were also very focused on their own developments, maximising production, oil price vagaries also focused their mind on minimising operating cost. This field is only - it's about five kilometres across and 70 kilometres long. ARCO drilled a well called Fiord in 1995 and they essentially discovered the well but they - or discovered the field but they discovered it - they penetrated a very narrow section of the field and they were looking for a deeper reservoir. As a consequence of that, they didn't test it.

There was another well out here drilled a couple of years later and it missed the front of it so what they found was that in between a five-mile distance between the Fiord and the well drilled out here, Colville River, there was a significant thickening of this reservoir section. The way that it was identified is that this is the Colville River so there was a real problem with seismic acquisition. In 2011 through to 2013, a number of 3D seismic programs were required and that led to this map here which essentially is an amplitude distribution map and the high amplitudes show the distribution of this sand. What you have here is a wedge of sand that's just been missed by the other operators, immediately adjacent to a field.

As I said, a number of us who have got sequence stratigraphy backgrounds recognised this is just a classic sequence stratigraphy play. There's nothing complicated. It's just something that you need a 3D seismic and a little bit of serendipity to define.

This shows you the sand that was penetrated in the original well. The USGS or the NPRA actually went out and - so, this was identified as part of the Qannik field and the estimate of - the resource estimate by the USGS at the time was somewhere about 120 million barrels. Little did they know, five kilometres away this reservoir section thickens massively. You get 880 feet of gross sand, a 650-metre oil column. We're calculating that as - you'll come up. We calculate it somewhere between 501.2 billion barrels of potential resource in there but it needs to be appraised. I'll go through that in a little bit more detail.

This was followed up in 2017 by the announcement by Phillips. Phillips have been watching this pretty carefully. I think that there was probably some early scepticism by Phillips as to whether or not this was real because it had been under their nose for a long time. They essentially followed up very quickly with the Willow discovery and they're now following up with two appraisal wells or two exploration wells that will be drilled specifically on the Pikka Horseshoe trend this year.

This map here really just puts it into perspective. ConocoPhillips are sitting out here in the west. The wells - the other exploration area's sitting here. This is the shelf margin so, this is actually also to the reservoir model that we developed when we built our reservoir simulation model to calculate our reserves. Just in the Pikka unit only this system goes for 32 kilometres in a north-south direction and is over four kilometres wide. If I put that into a map section, for people who are more familiar with this, if you can imagine this is the section on which the reservoir was deposited so this is the shelf margin. This is the Alpine field. This is the Kuparak field. So, you can see that there's not a big space to fit in a major oil field but what you have here when you actually map them, this is the net sand thickness superimposed on that structure. This is the distribution of the sand coming off the shelf edge. So, it's a very long - 70 kilometres long system. Up here is what's called Pikka North and that'll be the object of an exploration well at some stage in the next couple of years. That has potential for a substantial increase as well so, when we talk about our 500 million barrels acquisition case we're only talking about the area within the Pikka unit that was part of the development.

You'll also see just how close Putu well is in the ConocoPhillips area and the Stony Hill well. Phillips are evaluating the continuity or the extent of that entire trend. You will have heard us talk in the past about the possibility of drilling a Pikka-2 well this year. One of the things we're waiting to see is if the ConocoPhillips well is drilled because if you're actually appraising this field, there's no point in drilling two wells within two miles of each other because we've already traded - a collective we, it's Bill's baby. The Horseshoe well was pre-traded for Putu so, we'll get that information. One of the things that we'll be talking about with Repsol and Armstrong is the need to drill the Pikka well if we're getting the Putu well and coming out in the next season with a very comprehensive appraisal program.

One of the things that's exciting for us is we've done this - we've looked at this acquisition obviously with a focus on the development but this is a - it's not only the Nanushuk reservoir that has substantial potential here. This is a stratigraphic column. I won't go into it in detail. This is the reservoir sequence. Each of these are potential objectives in the area of interest. Nanushuk at the very top wasn't considered to be a primary objective until the discovery of the Pikka unit. The majority of the focus and the majority of the oil is in the Alpine down to [unclear] and into the Torok area in the deeper section. So, people drilled through this on their way going to the deeper area.

When we did our analysis, this is an amplitude distribution map essentially of this section here, Alpine C, and there are two wells that discovered oil in Armstrong Repsol's block in this area that have actually been included in the development plan. Recent inversion work using the 3D seismic has actually substantially upgraded the distribution of that sand. This is very, very recent but it highlights that the more and more information - the more technology we throw at it the more information that we're finding in terms of the upside. The next time we talk we'll talk specifically about what the potential scale of the opportunity is in there but it's multiple hundreds of millions of barrels potential.

In regard to the exploration - we're going to have a break in a minute because it's a long time to concentrate but in regard to the exploration, I talked a little bit about the field itself but the exciting part also is the exploration portfolio that

Bill and Repsol have generated. I'm not sure if many of you followed the recent lease sales, Repsol and Armstrong were very successful in acquiring a number of additional new licences that we'll have the option to back into once our transaction's closed. But importantly, the key to success on the north slope is the acquisition of 3D and being able to predict the distribution over these stratigraphic traps. What we've identified through the course of the analysis, we've identified over 20 prospects and these are all delineated by 3D. In those 20 prospects there's an additional billion barrels of unrisked prospective resource and what we'll be looking at is utilising the appraisal program in 2018/2019 to also test some of those concepts by drilling deeper into the Torok fan. Not only will we be appraising the field but there is substantial upside that can be tied into the existing facilities.

This is straight off the press. This is an amplitude ratio map or ratio seismic line that Armstrong provided us last week in our workshop. What it does, this is the quality of the size when you see all these prograding wedges and each of these prograding wedges are prospects and exploration targets in their own right. This is the Nanushuk-3 oil field. That area there is simply the distribution of the sand that extends 70 kilometres in a north-south direction. What we'll be also doing is we'll be mapping and doing amplitude analysis on each and every one of these exploration targets. You can see why Repsol, Armstrong and ourselves are pretty excited about this but also why Phillips is also following up this in their area.

This is our last slide before we have a break because we've been doing for a while but what this is, is a waterfall chart that shows where we see the resource growth potential in the area. When we talked about going for a new business opportunity, we weren't going to be in a situation where we were picking up licences all over the place that had no synergies. The focus for us was and very much is where is our next PNG, where is our next area that we can develop a PNG scale business? We actually think that the basis of what we've done in this transaction could very well be that.

This is the base acquisition price based on the Pikka development and the Alpine field, which I showed you before. Pikka satellite development is the appraisal program that's required to get up to the Armstrong Repsol numbers, the Horseshoe appraisal, exploration, Horseshoe exploration and the exploration in the other areas. What we see is there is an awful lot of running room not only to develop these fields in the near term but to appraise and add to the development and production over a period of time.

We see this opportunity - I'll stop in about two seconds before I get into the development but this opportunity provides an acreage footprint that has multiple exploration targets. We've come into this with a very conservative basis of our reserve estimations relative to what other people are suggesting and given the fact that we've had two majors approach us directly when we're not even on title yet, actually behoves to the quality of this asset.

I might stop there and maybe just take a couple of questions before we have a break.

Sorry about racing through that but…

Peter Botten: Keiran, you might mention that the actual presentation is on our website.

Keiran Wulff: Okay.

Peter Botten: And released to the ASX so if you have connectivity you can [unclear] using [unclear]. Questions for Keiran or any of us actually?

John Hirjee: (Deutsche Bank, Analyst) Keiran, John Hirjee from Deutsche Bank. A question on the exercise option. Do you need information before you exercise like a well result or appraisal result? Or is it just at that time you've got to make that call?

Keiran Wulff: No, it's a good question, John. We're going to have information upon which to make the call. We're going to have the ConocoPhillips information, we'll have a major appraisal program as well. That's why we didn't want it to be a short option. We wanted to have at least two seasons. The first one we're probably not going to influence. The second one we're definitely going to influence. So, before leading up to an FID decision we wanted to be able to have information that we could add value and be able to on-sell that option to the right party.

The other issue, what we wanted to do was to develop the relationship with Repsol because Repsol are 49% in the development. They've expressed potential interest at the right time to dilute to whatever is an appropriate - so, between the two of us we've got an ability to really bring in the right partner.

John Hirjee: (Deutsche Bank, Analyst) Thank you.

Ben Wilson: (RBC Capital Markets, Analyst) Thanks, everyone. Ben Wilson here. I just had a quick follow up question, Keiran or Bill, just on that ARCO field to the west, the Alpine. You gave some detail on it. Are those sands or the field there, is that an underlying or overlying sand?

Keiran Wulff: It's a deeper sand.

Ben Wilson: (RBC Capital Markets, Analyst) Deeper sand.

Keiran Wulff: Yeah or it's an older sand.

Ben Wilson: (RBC Capital Markets, Analyst) Okay and you put up some targets there. You suggest you've got some of that sand, it's oil bearing in your acreage there?

Keiran Wulff: That's right. We do.

Ben Wilson: (RBC Capital Markets, Analyst) Okay so, you'll be able to test that through your appraisal wells this year?

Keiran Wulff: We will. In the next season we will definitely be able to do that. I'll actually cover that in the next section. I'll show some of those slides.

Ben Wilson: (RBC Capital Markets, Analyst) Okay. Alright, good one. Thanks.

Bill Armstrong: That Alpine field was founded in the late '90s, it peaked at about 130,000 barrels a day. The average pay in those fields is about 43 feet on a per well basis. The two wells we drilled on our acres last year or the last couple of years, Q5 and Q9, the thickest Alpine well ever in the history of the Alpine, thicker than any well in that Alpine field so, we have substantial Alpine reserves. It just overshadowed - we've been here right now talking about the Alpine [how great] that was [unclear].

Ben Wilson: (RBC Capital Markets, Analyst) That's great. Thank you.

Dale Koenders: (Citi, Analyst) Hi, Dale Koenders. A couple of questions. How do you see the balance between a need to move towards development with unlocking what could be really material resource growth? How do you prioritise those two, following on from Ben's question?

Keiran Wulff: I suppose the key issue here is that we've got a development plan that's already been submitted for approval and we see that the best option is to progress with that and look at - it's a material development in its own right, new potential somewhere between an 80,000 or 120,000 barrel a day facility. As I said before, we're talking about potential discussions or we are talking about discussions with ConocoPhillips in the cooperation and utilisation of facilities. One of the key issues here is that you saw on Bill's slide, production is declining in a number of those other fields which means there's ullage and spare capacity in the pipelines and the facilities.

The answer to your question is you should focus on what you know and develop what you know and there's capacity for growing production using the ullage and expansion opportunities that exist with adjacent operators. We're very, very focused on optimising the development of Pikka first and foremost and what we don't want to be doing is always continuing to delay decisions for what's over the horizon. We'll be making the decision on what we know.

Dale Koenders: (Citi, Analyst) And then if I may as cute to ask Bill a question, in terms of the resource slide that's now been presented and you said that Oil Search had been quite conservative in some of those numbers, what would be your view of the upside potential that exists in all those horizons? Does that get you to your 3-billion or is 3-billion just the start?

Bill Armstrong: It's like throwing this huge softball my way. Yeah so, the Nanushuk is roughly the 3-billion barrels. The Alpine is another 250 million barrels. We have an additional zone called [unclear] which is another couple of hundred million barrels and then we have multiple other smaller sands as well. So, you tab all that up and it's probably close to about 3.5 billion. It's really quite delightful. I don't know why these guys gave small numbers to you but that's just the way they are I suppose.

Keiran Wulff: You can actually see why negotiations were quite tough and why we did a bottom-up evaluation but anyway.

Peter Botten: I'm almost crying [unclear].

Keiran Wulff: Indeed, but anyway, the numbers we're presenting are the numbers we're comfortable with and the numbers we're making decisions on.

Barry Dawes: (Martin Place Securities, Analyst) Barry Dawes from Martin Place Securities. Two questions. One, you sort of touched on it with the last question, is there chance of earlier production than 2023? And secondly, what can we compare and contrast with this field with Prudhoe Bay itself?

Keiran Wulff: Okay, it's a good question. We looked at - when we first looked at the asset we were saying can we bring on some of these fields like the Alpine field early? One of the key issues here though is that as part of the environmental impact assessment, these things you've got to look at what is the minimum environmental footprint that you can propose here. I suppose going to the heart of Dale's question, you want to do this right and you want to do this right once.

The issue for us is that when we looked at it, the development of bringing on some of these easier to market fields, the economics were that scale matters. I think Bill talked about it before in terms of you want the minimum economic scale and minimising the economic footprint working with the local communities so you're managing expectations. All of those sorts of things, you want to get it right once so, the development that we'll be doing will be focused on the larger scale development and then tying it in optimally.

With respect to Prudhoe Bay, Prudhoe Bay is right near the Deadhorse supply base. That's about 50 kilometres to the east. It's a large field. It's combined structure with stratigraphic trap. It's enormous, 12.3 billion barrels and still producing about 400,000 barrels a day, of that order.

There aren't a lot of analogies. It's a different field. The important point about Prudhoe Bay is because of the scale of Prudhoe Bay is that you've got phenomenal infrastructure in which to tie into. That infrastructure has ullage and there's also a major, major supply base, very different to Papua New Guinea and the highlands where you fly in everything. It's a major supply base where there is a number of rigs' workshops, materials and all of those sorts of things. It's a 365 day a year access supply base. The benefit is that you're riding on the back of the success of BP and the fact that they're towards the tail end, which means you're not competing for infrastructure utilisation.

Peter Botten: You just might make a comment around we have to take on the basis of not being - or keeping a balance. Clearly, we want to develop a cooperative development but there is a need to have an appropriate negotiation [unclear]…

Keiran Wulff: Absolutely.

Peter Botten: …around [unclear] access to our operations.

Keiran Wulff: Yeah, indeed. One of the things here is that the development plan is a solo development plan. It actually assumes no cooperation and the analysis that we conducted during the process assumed no cooperation. You always - as Peter said, when you go into any negotiations or discussions with a resource owner, you need to be able to develop it in your own right. Anything above - any cooperation that we are able to achieve is above and an improvement upon what we've actually already included in our analysis.

Probably a good…

Peter Botten: One more question.

Keiran Wulff: One more question.

Scott Ashton: (BBY, Analyst) Keiran, Scott Ashton here. Just on the option agreement, can you transfer that or sell that before the 18 months is up?

Keiran Wulff: Yeah, no problem, we can…

Scott Ashton: (BBY, Analyst) And then how does that affect, say, someone coming in on the development? Do they have some ability to influence the development?

Keiran Wulff: Sure, we can do it at any time. From the day that…

Peter Botten: [Unclear].

Keiran Wulff: Well, maybe not quite. We haven't got CFIUS approval yet but the reality is that we've got the total flexibility to do that whenever we like and we can maximise the value of that option by bringing in someone at the right time. If they add value, you bring them early. We'll do that. If it's a commercial or a financial arrangement, we'll do that too. We've got total flexibility to do that at any time.

Tony: (Analyst) Hi, Tony [unclear]. Just a question, Bill said it was important to bring in the right partner and he identified Oil Search. Is this too big for Oil Search in its own right? I mean you talk about this option but it seems like the option is you exercise your option to give it to someone else or to sell it to someone else. So, is this development too big and you've got Papua New Guinea on one side and you've got this on the other side, do you also maybe have to make a call which is the asset you really want to go for or do you think you can do both?

Peter Botten: No, we think we can do both. Put it into perspective. The CPF and the development here is exactly the same size as PNG and we operate that already. PNG, when it was developed, was a 140,000 barrel a day facility from

Chevron. The infrastructure and the facilities are exactly the same. It's something we're totally comfortable and familiar with.

In terms of the development drilling, we've got the alliance with Halliburton similar to what we did in the original program when we took over Chevron. So, this isn't unfamiliar to us. It's not an area that's remote like Papua New Guinea where you've got to learn the logistics. It's infrastructure roads, 24/7 access. So, no, we're actually pretty comfortable with this on the proviso that we utilise a solid knowledge base that exists in Alaska, we maximise the alliance with Halliburton and we've got the flexibility to bring in the right partner as needed, as I said to Scott's question whether that be an operational or a financial partner. But it's very, very similar to what we already do in Papua New Guinea.

Unidentified Participant: Bill, given your relationship with Conoco and the potential necessity for them as a joint venture, can you maybe give some advice to Oil Search about how to deal with them?

Bill Armstrong: Have some red meat. The level of respect I have between Conoco and me is very high. The CEO and I are really good friends but they were more than happy to put their foot on my neck just because they knew I was an under-funded guy. I wish the oil and gas business was played on a nursery school playground but it's not. So, bringing Oil Search in with their track record of doing deals and facilities, et cetera, et cetera, they're the absolute - in a such stronger position to be able to negotiate with Conoco regarding access to their infrastructure and whatnot than I ever was.

I could sit there and pretend to these guys that I'm going to go to developers because look at me, wah-wah-wah but they didn't take me seriously just because I've got a couple of dozen people. This is a job for a company the size of Oil Search, not me.

I know this. I know that Conoco has an under-utilised facility with lots of ullage and this could be quite a profitable centre for them, just work out a deal with Oil Search and Repsol and take their oil and run it through their facilities for a fee. It would probably eliminate over $1 billion or a $1.5 billion of cost that we would have to put in and yet they make a lot of money. So, there's a win:win in this scenario completely. Make no mistake, Conoco wanted my asset so, when I sold it to Oil Search they weren't 100% happy with that.

Could we add one more comment? I think it's interesting in life that a lot of times you can define something by what it's not I think as much as anything else, kind of like when you buy a house. No, I don't want this, I don't want that. Alaska, there's a lot of nots about Alaska. It's not offshore. It's not deep water. It's not [H2S], it's not CO2, it's not hot, it's not HBHT, it's easy from the standpoint of everything below ground is normal. It's shallow depths, normal pressures, no CO2, no H2S, regular reservoir. These individual wells in this field I think would probably be somewhere between 10 million and 15 million barrels per well. It's massive.

So, if anybody has a question about whether Oil Search can pull this off, from a purely operational standpoint it's right in their wheelhouse. It's just not that difficult. It's not like - the technologies that, say, Conoco has up there and BP and Exxon, basically when you get right down to it it's just shared technology with all the other suppliers up there, the drilling companies, the Schlumbergers, the Halliburtons, blah-blah-blah. Does that make sense? Good.

Keiran Wulff: Just one other comment on that before we break because we will have a slight refreshment, is that I think we've got pretty good over the years about being able to manage relationships with large organisations such as ExxonMobil and now ExxonMobil and Total. I think we're only one of I think two or three companies in the world that actually operate on behalf of ExxonMobil and we're drilling the holes for them and we're doing the seismic for them and we're doing key parts of the operations including running the weakest link of LNG which is the liquids export facility. If we shut down I think it's only three-and-a-half, four days before LNG would shut down and we have the confidence of Exxon to actually deliver that. I think we've got a bit of a track record of working with majors and we have discussions lined up with ConocoPhillips in January and that'll be part of that process.

Coming back to your question around can we do both, absolutely we can. We're not betting the farm. We've got a 25% interest in these fields and we believe that's a good equity with huge optionality with the option.

Anyway, it's now 20 past I think or 23 minutes past. Let's say quarter to 12 to resume, 15 minutes break, a quick comfort stop and a coffee/tea. I believe that's downstairs or actually out the front so, let's resume at 11:45. Thanks.

Peter Botten: Ladies and gentlemen, we're going to resume a process check. Keiran is going to run through some of the development areas now and some of the softer issues in terms of how we're going to manage the operations and focus on things like the landowner issues and stakeholder management. We then will go into a short update on PNG LNG and then a discussion of the balance sheet that Chelsea will lead and then we'll have some Q&As at the end, recognising that we're all reasonably busy and we need to - as we're approaching lunch.

Keiran, over to you in terms of touching on the development.

Keiran Wulff: Okay, thanks, Peter. Let me just get organised.

Okay, what I'm going to do now is just go into a little bit more detail about the development asset, some of the questions that were raised before about what happens if we have additional success.

The important point about this asset is it's not an area that is isolated. It may be in the top of the world but there's a substantial amount of infrastructure and facilities that we can tie into. The weather doesn't always look like that and it certainly doesn't look like that at Deadhorse. When I was there it was very, very different. But Deadhorse is the supply base that supports the industry. You can see it's a major supply base. There's a substantial amount of kit up there. Every major contractor has an operating facility or warehouse up there so, you can see that we're not too far away from a major area where we can get support.

In regard to the map on the left, you've seen this a few times, but I'll just highlight where the major areas. Prudhoe Bay is here. Deadhorse, Kuparuk River 2.8 million barrels, Oooguruk and Nikiatchuq up here. Eni and Shell will be drilling one of the longest offshore multilevel lateral wells. I think it's 36,000 feet will be targeted, you know, drilling up from an island up to the north. So, there's some significant activity going on this year. Conoco Phillips's area is here and you can sort of see this is the Pikka Unit here.

This map also shows you the distribution of the road network all the way up to Mustang. These will be ice roads going into our exploration activity which will ultimately be gravel roads. The TAPS pipeline in the middle is the pipeline that goes from the top of Alaska down to Valdez where the loading terminal is. The capacity of that pipeline is 2.1 million barrels and it's per day and it's currently got a throughput of about 500,000 barrels. So, obviously you pay tariff but the important pointer here is that it's not isolated, there is existing infrastructure, we've got a very, very supportive government and a very viable project on the basis of the appraisal program.

Getting into the development plan. So, this was our acquisition case. This is where we talked about on the basis of what our valuation was. So, if you look at this particular scenario, we model 400 million barrels out of Nanushuk and 100 million barrels out of the Alpine Sea. We saw there was a potential between 80,000 barrels to 120,000 barrels of oil a day by mid-2024. The production forecast curve here is that 80,000 barrels a day, clearly at 80,000 barrels a day you have a longer plateau. At 120,000 barrels a day you have a shorter plateau with a quicker decline rate. So, it's all about economics and it's all about making sure that we get our scenario correct.

Armstrong and Repsol's development plan, that was submitted for the Environment Impact Statement in 2016. It called for three drilling pads. The drilling pads, this is the Pikka Unit. That's 8 kilometres so drilling pad one, drilling pad two, drilling pad three, and you'll see a whole series of multilaterals that are drilled away from the single drilling pad. So, this is a little bit like a deep-water development. You minimise the footprint and you minimise the environmental impact.

Conoco Phillips CPF for Alpine field is located here and you'll see that the orientation of the wells and these are - there's a producer and an injector so you're drilling two wells for each location and this is a very, very standard format for the slope. So, we're talking about 65 or thereabouts oil producing and water injectors, but what we also now see is that we also see that there's significant optimisation opportunities simply on that plan alone, which I'll go through. So, we've already started having discussions with Halliburton as recently as last week where we'll be going through looking at drilling optimisation, cost reductions, reservoir sweep efficiencies and most importantly, how we minimise the footprint of any development up there so that we're taking into consideration all of the community concerns.

What does that look like on the surface? It's again, I'm not going to go through this in detail. You can read about this little bit later, but this is the development plan that was submitted in 2016 to [NEPA, which is the National Environmental Policy Act and they go through a process with the US army corps of engineers, where they undertake an independent environmental impact assessment. We expect that's been going through the community engagement program. We expect to have some results coming through from that by third quarter 2018.

One of the things that Oil Search is going to be doing with respect to that program is looking at how we can optimise that. We'll be talking to the community, we'll be taking into account discussions with some of our contractors, looking at optimisations and we'll also take into account discussions that we will be having with ConocoPhillips about how that plan may be optimised. But importantly, Armstrong and Repsol have gone a long way down the process and approvals stage of actually getting this implemented in the first place. But this will be a very, very significant core focus for us early on to fully engage with the community and identify long-term alignment projects so that we can get this project going forward.

The difference between us and ConocoPhillips, ConocoPhillips are on the west side of the Colville River and they have a fly in, fly out. It's a seasonal approach in terms of the roads, so they have ice roads. They don’t have gravel to their - gravel roads to their facilities because they’ve got to cross the Colville Road. The attraction about the Pikka Unit is it's on the east side. It's close to existing infrastructure and you don’t need to build a bridge or anything else across the Colville Road. So, there'll be 24/7, 365 day a year access via roads to these facilities, and that has a significant impact on your operating costs.

Just so, I'll put this up and this will really thrill a lot of you in the audience. This is essentially the well design, you know, for the Pikka Unit. These wells will be long distance multilaterals. Some of the longer wells will step out 26,000 feet. As I said, that's not unusual. Eni and Shell will be drilling a 36,000 feet step out well this year. What I wanted to show you on this curve is really this map here. This is an envelope, this is feet. This is the drilling that's occurred in terms of worldwide extended reach drilling and this is where the Pikka Unit falls. So, you can see that the drilling plan for the Pikka Unit falls within a very clear envelope of what's been achieved across drilling practices worldwide. So, we're not trying to do something that hasn’t been done before and it's something that is commonplace on the slope. But what it does do is that we can use a lot of the technology and the developments that have occurred in the lower 48s and in the US in general to really optimise this program. Because when you're talking about a drilling program of 100 odd wells, you're going to have a lot of learnings and a lot of cost savings that will be developed.

In terms of the next stage, you know, Bill talked about just how big this thing could potentially be. I just want to show you what - where we're currently at. Our phase one acquisition is the area in green. So, this is the 120,000 barrel a day case which you saw in the previous slide. What we've also looked at is how do we get to the Armstrong and Repsol numbers of 700 to 800 million barrels? Well quite clearly, you know, there are a number of factors which is this is a sensitivity analysis and we did an awful lot of that during the course of the bottoms up work that we did. What were the key issues and the key sensitivities that can actually affect the resources that we apply to this project? So, for example, if we increase the - we have a very conservative recovery factor which was the topic of many conversations with

Armstrong used for this development of 26%. Some of the reservoirs in the area, and Alpine next door using enhanced oil recovery techniques, have in excess of 50% but it's a different reservoir. So, the reality is what we're looking at doing here is how can we actually optimise recovery through sweep efficiency, enhanced oil recovery, but on the basis of simply increasing our recovery from 26% to 35%, you're getting into the sort of the 700-million-barrel case, which is where Armstrong's and Repsol's current program is. So, it's not hard to get there, but what we've done is we've gone on what we think is a conservative and an appropriate planning case in this regard.

That slide there is the one you'll have seen and we've talked about and Repsol strongly believe and we hope they're right, and based on the work that the quality of the work they've done that there could well be. But they've made a release back in March 2017 where they believe that there's 1.2 billion barrels of oil in this area. So, what would the development look like if it was 1.2 billion barrels? So, you know, that effectively would be a 1.2-billion-barrel scenario based on Repsol's number.

The important point here is that what we intend to do is we'll be looking at each and every one of these scenarios through 2018 so that our 2018/2019 program targets and evaluates each of the concerns or the challenges that we have to actually - where we get from our acquisition case to get to Armstrong and Repsol's cases that they believe where there's more oil. So, the 2018/2019 program will be very important in defining exactly what resource base exists ahead of an FID decision in 2019.

The big difference known, and this one here is - and I just wanted to show it to you - I've shown you this slide before. This is a cross section of effectively the prograding shelf margin. This is the reservoir model from Repsol and Armstrong and they look at contribution throughout - from all throughout the entire section. This is our more detailed model. Well, it's not more detailed but it's just our model that we use for our modelling. We've only applied contribution from the green and the yellow, which is facies A and B and a very minor contribution from the orange. We've assumed no contribution from the brown in regard to the deep-water facie. So, we're focusing on where's the oil actually going to come from, so the biggest difference - point of difference between us is that we're really saying that it's only going to be the good reservoir quality where we get some decent contribution. It's not too different for those of you who are familiar with the Antelope field where we have that fantastic reservoir at the top and a big question is what's the ultimate recovery factor out of Antelope because there's that tighter section below. Obviously over time, we think there'll be a contribution from that tighter section but you can only bank the top. So that's the big vagaries of early reservoir and reserve prediction when we haven’t got the appraisal results with us.

We put this slide in - a lot of people out there are looking at it for guidance in terms of what this could be, and I won't go into detail. There's a lot of detail in this slide, and as Peter said, it's up on the web and you'll be able to ask us questions about it a little bit later. But what we wanted to do was quite simply show how do we go from 500 million barrels to a 700-million-barrel case simply by looking at things like recovery factor. Also, what could happen with respect to when you're drilling so many wells, it has a substantial contribution to the overall CapEx. What can you do when you actually get some learnings and 100 wells is an anticipated 30% learning curve based on past practices. So, what does that mean with respect to development costs, you know, dollar per barrel, breakeven and things like that. There was a lot of discussion early on about the quality of this asset. Wood Mac had an early evaluation of it and they'll put out a subsequent revision in more recent times.

What we believe based on our breakeven costs, we see 500 million barrels at about $37 a barrel. If you actually look at enhancing recovery and optimising the development, you know, that can go below $30 a barrel. When we look - what we also wanted to do is go to the next slide and how does that compare to global breakeven costs for new developments. So, this is a Wood Mac's slide and we appreciate Wood Mac's approval to show this slide. This is a very recent slide looking at more than 75 potential developments globally which are more than 50 million barrels and so what's the breakeven of each and every one of these fields based on Wood Mac's analysis. Now, quite rightly, the companies who own these fields will say that there's optimisations which will drive these costs down, but what we're looking at here is that our acquisition, you know, our acquisition sitting here Wood Mackenzie amended their proposal, or their analysis in November 2017 and reduced it to $42 a barrel. It's still in the top half of the global yet to be developed fields. If we're talking about $30 a barrel, we're talking - where we think it can quite easily get to, you're talking around about $30 a barrel and when Peter talks about Tier 1 assets, it really highlights that this, given the political stability, the commercial terms, the recent tax changes which will hopefully be enacted into legislation, it really does make this a true Tier 1 asset on a global scale.

So, the indicative timetable to first oil is, so you've seen this slide before. There's quite a lot of activity that needs to occur in the appraisal period through 2018 to mid-2019. FID, when you're with an FID decision sometime in late 2019/2020, but importantly, what we need to do is we need to work with the current development plan, look for optimisations, identify what is the optimal appraisal program in 2018 and 2019 in Pikka and Horseshoe? Work with ConocoPhillips and see how we can potentially optimise it in both parties' interest, and they'll be discussions that we will certainly be having and encouraging. So, the next 18 months will be a very, very important period for this particular asset.

Development will occur over a two-and-a-half-year period and first production will occur in all likelihood sometime late 2022, 2023, something like that. The Alaskan Government is very, very strongly supportive of this particular asset and this production and something like this will provide something around about $300 million a year in royalties. So, it's something that gets a lot of focus by the state government. So, we're very focused on it, we'll have a very clear development plan and we'll be able to utilise what's been done to date to optimise it going forward.

In terms of the stakeholders, you know, this is something that Bill talked about as to why he liked the thought of Oil Search coming in. We've already had discussions with each and every one of these groups. We haven’t been out to the village of Nuiqsut yet, but we certainly will be very, very soon. But quite clearly, Oil Search has a very strong and you only realise how strong the niche is when you actually go to some of these places where in our backyard we think we're good, and we're very focused and we are committed to it. It's part of our DNA. But when we actually go to some of these other places, you see we really are good at it. It's something that we do genuinely care about. It's something that we're looking for a long-term solution for all of the key stakeholders, not just a quick win for the developers.

So, the conversations that we've had with each and every one of these things has been pretty robust. It starts off with a fairly jaundiced perspective of a newcomer and where we're at at the moment is some very, very positive discussions recurring with each and every one of them.

The key parties, as Bill said earlier, are the Kuukpik Corporation. It's a small village or represents a small village of about 500, but it's a very, very important subsistence village and we can go into a little bit more detail later, but there are people who are passionate about their land and passionate about the preservation of their way of life. The Arctic Slope Regional Corporation is a lot larger organisation and they have a direct ownership of mineral resources in the area. They're about a $2 billion a year organisation and with a lot of capability, very sophisticated and someone that we hope and we'll be looking forward to doing a lot more work as we will be with Kuukpik Corporation. Then we talked about the State of Alaska and the State of Alaska is very, very focused on responsible and environmentally sensitive developments, but they are very development orientated. But a very good group of people.

As we said, community alignment, if any company should be able to do this, it's certainly us. It is part of our DNA. We've had a number of community meetings with organisations that have already commenced. We'll be running a number of workshops, reviewing the challenges and opportunities and our plan is a very, very active community engagement program to assure alignments. So, maximising cooperation, we absolutely intend to minimise our footprint, environmental footprint, look for sustainable business opportunities, and just any other initiatives that can go forward. But most of all, one of our key focus is to ensure that we preserve and respect the culture of the people that exist up there.

This is the last slide fortunately. It's a bit of a race through but it is indeed a very challenging environment. Quite unique, incredibly beautiful and there's a lot of responsibility put on each and every operator up there to preserve the beauty and the sustainability of the operations up there. The slope temperatures are never really get more than 15 degrees Celsius during the summer and they fall to below 40 degrees Celsius in the winter, and that's before you actually add the wind chill factor. The exploration is done on ice roads and they essentially all melt, the pads all melt. So that when you actually go up there to see what the environmental impact of the operations, it's zero. You cannot see where the previous season's operations were apart from the well head sticking out of the ground. What you can see is some of the 70s and early 80s work before they were generally sensitive to the impact on the Tundra. So, the commitment to environmental sensitivity up there is actually really good to see.

We'll have a number of environmentalists on staff. We'll be bringing in across Bill's group into our team who are very, very experienced, ex-Conoco, ex-BP people who know the system. This is something we will be relying very heavily on local expertise, but we'll also be ensuring that that local expertise minimise - or meets our minimum standards because this is something that we won't be compromising on. The way that we'll be running this is that there will be a very autonomous team. I got a question beforehand to make sure that we're not going to lose focus on PNG. You know, quite the contrary. What we're looking at doing is, you will see that over the last couple of years, we've really built our PNG position, our focus, our team structures, and we've got our acreage position optimised in PNG very, very nicely. PNG will have its own - will continue to have its dedicated focus and priority within the organisation. The way that we intend to run Alaska is that there'll be a dedicated Alaskan team which will be based primarily in Anchorage. It will be a small group of Oil Search management, you know, supplemented by Bill's team, new hires, Halliburton Alliance input and people like that. We'll also have Sydney support in the subsurface and compliance oversight but it will be a very autonomous group reporting into the corporate, but there will be no diminution in our focus on PNG.

Events going forward. Again, you can read those. A lot of people talked about when's there going to be a field trip? Recently we talked about a field trip in February. I think it probably - that's a little bit too cold and a bit too premature so what we'll be looking at is an investor field trip in the third quarter 2018. Once we've got a little bit more time to get our feet under the table and we know exactly what our plans are for the upcoming season. There are a number of early events around ConocoPhillips appraisal wells and the potential Pikka well and we'll be taking operatorship earlier than what we originally planned. In our previous presentation, we talked about 30 or 1 June next year. What's clear in discussions with all parties is that that needs to be brought forward because 1) we need to get our approvals and permits done for the following season, but you know, as much as people like Bill in Armstrong, people want to be involved and participate with the new operator. So, they'll be a more rapid transition and we're working on that currently. 2019 as I said, it will be a moving towards a four plus Pikka Unit Nanushuk appraisal program leading to FID in 2019/2020.

So that's a very rapid run through. So, we'll leave questions to the end.

Peter Botten: Yeah, thanks, Kieran. As you said, we'll leave the questions broadly in the interests of time, to the end. What I'd like to now, is just to give you an update as to what's happening in Papua New Guinea and obviously there's a significant amount of activity going on there right now surrounding the bringing all the pieces of the jigsaw necessary to commit to train further development there.

Firstly, let me just touch on PNG LNG project. Look, it's an outstanding success. It continues to perform well above the nameplate recent compressor upgrades in the plant site and now sees sustaining production above 8.6 million tonnes. It's actually got on a daily basis up towards 9 million tonnes and we're very, very comfortable and very pleased with the performance and continued sustaining performance of this plant site and the reservoirs associated with it. The compressor upgrades have now been completed and, as I say, for 2018, we're looking at certainly sustainable production well above 8.5 million tonnes, though there is some further modifications and the first significant modifications to the Hides Gas conditioning plant and the tie in of the Angore wells is planned for the first half of next year. So that will bring down the daily production rates a little bit. It really is a very, very strong globally competitive production cost, sub $6 BOE and the project continues to be really, really well positioned in terms of reputation in the market and reliability and delivery of sustained high levels of production.

In the marketing of gas that's not presently contracted, we've actually leveraged a recent tightness in the market and a substantial peaking of spot pricing in the market to really leverage our short-term sales of an extra 1.3 million tonnes and we've very recently been out to rebid because we think we're right now in a very sweet spot to be able to secure some three to five year markets and frankly, we've been very positively surprised by the response and the response is substantial number of parties, both direct buyers as well as some traders. Right now, we're in negotiations with a number of parties just to close that off and the slopes are substantially above present spot pricing and really very positive. So, we've used, I think, a very good and sweet spot time in the market to be able to leverage four to five-year sales leading into a 2023 production base for the expansion volumes. As I say, but both buyers and traders have been in this proposal. We anticipate that we'll actually get a heads of agreement with these people before the end of December and binding contracts sometime early in the year. But it has been a very good time, dare I say it, to get out there and market some LNG, given present tightness in the market.

In the overall LNG expansion, I can tell you there are substantial numbers of pretty intense discussions taking place right in a number of areas and the key pieces of the jigsaw that allow us to commit to expansion volumes, let's say 3 million tonnes from PNG LNG, and the final size and shape of an Elk-Antelope development are now coming into place. A number of those issues are being actively addressed as we speak and I came from meetings in Singapore earlier this week around high level discussions around project structures, how the gas is marketed, what the size and shape of any development might look like and at the moment, there are workshops in Yokohama with [Giotto] and our project participants actually talking about what their recommendations are for the size, an optimum size and shape for PNG LNG expansion and Elk-Antelope size and trains. It also looks at what facilities can be used within the plant site in PNG LNG and the final report and recommendation from [Giotto] are due into the joint venture hands on 22 December.

Now that is a key piece of the jigsaw for us to sign off on what we think an appropriate level of production base and the split in size and shape of each train. That really is an absolutely fundamental piece of us moving forward to go beyond principles around sharing into the detailed discussions and arrangements around how that can come together. Some of the pieces are clear already. Firstly, obviously with licence commitments, and government requirements, any expansion out of PNG LNG is almost certainly got to utilise P'nyang. Part of the process with P'nyang is that we are looking to optimise and extend the period of construction for PNG LNG expansion and Papua LNG over a much longer period of time than we had originally for PNG LNG. That will spread our capital spend over a long period of time. It may also allow us to optimise the development of P'nyang versus Muruk as resources go and are found up in that north-western corner.

The upstream FID, pre-FID or at least pre-FID and what we're actually going to build at Elk-Antelope and P'nyang are actually very, very mature, but one of the key areas of focus, as I say, is the [Giotto] work that's going on right now around how is the best use of PNG LNG facilities and the optimal size and shape of each train. That's the work that's being presented to us right now. A key part for PNG LNG expansion obviously is the P'nyang south well. We believe that the initial results of that well will be with us in around 10 days or two weeks. So, that is another piece of the jigsaw that's fundamental to understanding and commitment to further tonnes out of PNG LNG and optimising a relatively easy development around that space.

The project structures. IJV, UJV are being actively discussed moving beyond principles to the detail. There are a number of discussions going on and planned for part of this year and into the early part of next to build some further flesh on those bones, together with an agreed process of financing and linking financing to marketing arrangements all being detailed work now. So, there's a lot of activity and a building tsunami of work that we expect to continue to build in the early part of next year with engagement with government around what they see approval around an endorsement towards the final shape of volumes that we expect to be able to put through this plant. So, a very, very intense period going on right now and continued meetings day and week upon week out into the new year.

With that, I'll chuck it over to Chelsea. Welcome, Chelsea. As group treasurer, she's going to run us through our corporate finance overview.

Chelsea McGregor: (Oil Search, Group Treasurer) Good afternoon, everyone. So, I'm going to take you through some of the key financial inputs for PNG LNG, for LNG expansion and for Alaska before presenting a consolidated forecasted financial position for Oil Search, including its cash flow priorities. Oil Search has world-class assets. Our producing assets of PNG LNG in our operated oil fields generates strong free cashflows that we expect to underpin the cash contributions during the development phase. Our two growth projects, LNG expansion and Alaska, are expected to have modest development costs and I'll talk more about that shortly. Our other assets in the exploration and appraisal phase have a low CapEx commitment and a significant portion of discretionary costs can be curtailed if needed, and it will actually require our explorers to do some prioritisation of their expenditure.

Oil Search's liquidity position has never been better. We currently have cash of approximately $1.2 billion and undrawn credit facilities of $850 million taking our total liquidity to approximately $2 billion.

In terms of the key inputs and assumptions in our liquidity modelling, we have used a conservative oil price that is towards the lower end of our bank and industry peers. Our two priority growth projects are expected to have modest development costs, and that is being driven by the fact that they're able to share existing infrastructure from other projects that are already in operation.

Both LNG expansion and Alaska are likely to be project financed, which will further reduce the cash contribution required by Oil Search. Our consolidated debt is expected to peak in 2023, albeit the PNG LNG debt will be substantially repaid by then. Our current dividend payout policy will be maintained, and our likely development scenarios do not require any equity to be contributed from shareholders.

What I want to do now is just recap on the cash inflows coming from our producing assets because they are expected to underpin development costs, the cash contribution for the development costs for our growth projects. The operating costs for PNG LNG are in the lowest quartile globally. That means that it has a healthy debt service cover ratio, which is above the lender covenant of 1.25 times, which is required for distributions.

In this context, distributions refers to Oil Search's share of the PNG LNG project revenues after subtracting OpEx, CapEx, royalties, taxes, principle repayments, and interest expense. Oil Search has received distributions of $1.7 billion from PNG LNG to the end of 2017. Even in the low oil price environment in 2016 we still received a distribution of just under $200 million. Looking forward over the construction period between 2018 and 2023, Oil Search's share of PNG LNG distributions is forecasted to be approximately $3 billion, an upside does exist if there are higher production volumes or higher oil prices.

PNG LNG has been project financed with approximately 70% of the construction costs coming from external lenders. You can see in the pie chart in the top right-hand corner the sources of the lenders and in the bottom wedges in the purple, the green, and the red, that is the contribution from the export credit agencies, with the largest one of those wedges being the Australian Asia Pacific Region. The reason that the export credit agencies contribute funding to these projects is because there is engineering and construction procurement companies providing services to the project, and in this case because all of the LNG sales were sold into Asia.

We do expect a similar composition for LNG expansion. In the bottom right hand corner, you can see the debt repayment profile for PNG LNG, and it shows that nearly 60% is repaid by 2022 and the entire debt is extinguished by 2026. This will free up capacity for some of the same lenders to participate in LNG expansion. Finally, although our operated assets are mature they are ungeared and do contribute a valuable free cash flow during the development period for LNG expansion and Alaska.

Now I want to take you through the key debt assumptions in our modelling for both LNG expansion and Alaska. So the development concept for LNG expansion has not yet been finalised, so these numbers are Oil Search assumptions. Our assumptions estimate that our share of the development costs, before project debt is introduced, is estimated to be between $2.6 and $3.5 billion. We have assumed that the project will be able to achieve 60% project debt financing.

The equity contributions for the remaining 40% are estimated to be between $1.1 billion and $1.4 billion, and these will be funded from PNG LNG free cash flows, surplus cash, and undrawn bank loans. We do expect strong support from the government financiers, the multilateral agencies, and the export credit agencies, and as I mentioned earlier, the accelerated PNG LNG debt repayment profile will free up capacity from those lenders. The funding costs are expected to be similar to PNG LNG.

For Alaska, our share of the development costs before project financing is introduced, is estimated to be between $800 million and $1.3 billion, similarly, for our modelling purposes we have assumed that the project will be funded 60% by project finance debt and 40% by equity. The equity contributions are estimated to be between $300 million and $500 million, and that will be funded from PNG LNG free cash flows, surplus cash, and undrawn bank loans. In the graphic on the right hand side, you can see the debt issuances in the US market over the past four years to E&P companies.

Even in the low oil price environment of 2015 and 2016 a significant amount of debt was raised. To put it in context, 2016 the level of debt issued was just under $20 billion and yet Alaska requires a number less than $1 billion. In 2017, you can see now a move towards more reserve based lending style facilities, and that is a form of debt where the loan amount is tied to the project resource size and the economics of the project. We believe that the US debt market offers a range of financing options for this development and that also the funding costs will be better than PNG LNG, due to the capacity in the market and also due to the fact that there is no country risk premium.

So, no cash flow analysis would be complete without tax. So in the US, tax is levied depending on the state of operations and also on the industry of operations. There'll be four types of taxes for our operation on the Alaskan North Slope, and we've got an illustrative example here of how that will be calculated. The four taxes are - there's a state royalty, a state production tax, a state corporate income tax, and then finally a federal corporate income tax. Those taxes are not cumulative. There are various offsets, exemptions, and credits that when you amalgamate those the expected government take is assumed to be around 42%.

The Company take is expected to be around 58%, and that includes a 2% royalty for the private leaseholders. There is also some recent US tax reforms that have been announced in the US that could provide a net present value benefit to Oil Search of up to $150 million, but that is assuming that the legislation that's currently being tabled will be enacted as it is tabled and that may not happen.

So finally, pulling that all together and looking at our consolidated project finance debt for the three projects, you can see that our debt level will be its highest in 2023, and it's forecasted to peak at between $3.3 billion and $4.1 billion, that is lower than the debt that we took on for PNG LNG of $4.2 billion. We are assuming that our $850 million of corporate facilities will be maintained during the construction period and can be drawn down if needed. We can manage our corporate debt levels by curtailing discretionary expenditure if needed, and also if there are surprises with oil prices, project costs, and gearing.

In terms of compliance with our key lender covenants, the table on the bottom right hand side shows our gearing and our interest cover. Gearing is expected to remain in a range of 40% to 45%, which is comfortable below the lender covenant of 55%, and it's similar to the current gearing and well below our peak gearing in 2015 of 42%. Our interest cover lender covenant is [EBITDA] to interest cover above 3 and at all points during the construction period we believe the interest cover ratio will be above 3.5 times.

In conclusion, our cash flow priorities have not changed. We will have significant free cash flows from PNG LNG and from our operated oil assets. They're expected to generate free cash flows in excess of $3 billion. Our combined share of the construction costs for Alaska and for LNG expansion is not expected to exceed $1.9 billion. So that means we will have surplus cash flows above $1.1 billion before dividends and other growth initiatives. If any of our assumptions prove to be incorrect we have two key liquidity levers.

The first is we have the corporate credit facility of $850 million, and the second is that we have a large programme of discretionary exploration spend that can be curtailed if needed. Going forward into the operation phase, the PNG LNG debt will be repaid by 2026. We have assumed that the combined debt for LNG expansion and Alaska will be about $500 million a year, and that is similar to the current debt repayment levels for PNG LNG. Once all three projects are up and running, Oil Search will be generating free cash flows in excess of $2 billion to $3 billion per year. With that I'll hand back to Peter.

Peter Botten: Thanks, Chelsea, and I'll then wrap up and we'll open the floor again for questions. The reality of life is that we've got, we believe, two Tier 1 assets, and with the acquisition of Alaska we build on our ability to deliver material growth in high returning production over the next five or so years. The reality is that we do and are combining two world class assets [unclear] PNG and Alaska, and provides us with an unprecedented opportunity for growth. There is no doubt that we've gone into Alaska in what we believe to be a conservative and measured way.

We've approached the funding of Alaska in a conservative way, and we are looking to further optimise our position in terms of supporting developments there. We do think the LNG assets and Alaska are very complementary. We have acquired certainly Alaska at a highly competitive price, low operating project costs generally can be optimised both in PNG and in Alaska with obviously expansion in PNG changing and moving down the overall operating costs, as well as obviously optimising the development with Alaska.

We can and will focus on what the next phase of LNG growth will look like beyond trains 3 and 4. We believe trains 3 and 4 are making extremely good progress, though recognise that these are big projects, recognise that they're complex, and recognise that there are many people involved. But the key parts to allow us to understand how the size and shape of trains 3 and 4 are now coming into place is with a very active program over the next few weeks and months, building into a very, very active and comprehensive commercial and negotiation rounds between the parties and government in the first half of next year.

Unidentified Participant: [Inaudible question - microphone inaccessible]

Peter Botten: Yeah, it is. It says a lot of our people.

We do believe that we have a history of value-accretive M&A, and I think Alaska will prove that. Clearly, the enthusiasm that Bill shows for his soon to be partly ex-baby is something that we're very mindful of, but also, we are disciplined in the way we look at these things. I believe that Keiran has demonstrated in spades that we've actually done a bottom up approach, acquired it at the right price, with the right structure, and the right optionality, especially with the option to allow us to further optimise the development into the future.

I also believe that we as a Group have to concentrate and roll out to the market what we believe to be the appropriate commercialisation path for gas in Papua New Guinea in the first six to nine months next year. We are applying a very rigorous discipline in terms of capital spend across the organisation. In reality we need to have a vision aligned with our partners on what commercialisation beyond 3 and 4 can be for PNG, whether that be at the bottom end in the Gulf, with appropriate infrastructure capacity being built there in the next phase, or alternatively a mix between the Gulf and the Highlands, and again, the infrastructure required to make that happen.

I've mentioned already I think the next phase of LNG growth in PNG will be of longer duration. There is a desire by all of us to spread the capital spend across a number of years, and it maybe that that construction period in PNG could go on for seven or eight years, and concentrate initially on the downstream at Elk-Antelope, supported by gas from existing fields in PNG. P'nyang may be coming on after - and being built after completion of Elk-Antelope upstream and the two trains in PNG, a much smarter way of using our capital.

There really isn't any change by doing Alaska on how we can concentrate on delivering value to shareholders. We have a consistent focus and a separation on what we're doing in Alaska from what we're doing in PNG. There is absolutely no move away from changing our focus on delivering in our core assets, but equally and excitement and an enthusiasm to actually optimise what we've bought in Alaska. That really is I believe a lot of upside, by focusing initially on as early and as cost effective optimal development as we can maintain.

There will be, as I mentioned, very strong capital discipline in the organisation and prioritisation. There will not be a change in dividend policy in the short term. As Chelsea highlighted, we have substantial discretional funds and work programs that can be tweaked in the event that there be a change, either to oil price or a combination as we model oil price capital costs and timing. In my view, in 24 years in this place, we've never been better to actually drive long term shareholder value and we have some absolutely outstanding assets, both in our assets in PNG and now Alaska, but also our people to be able to deliver on that and hopefully you believe us.

So thank you very much for attending. If there are further questions we are very, very, happy to answer them across all that space.

Dale Koenders: (Citigroup, Analyst) Hi, Dale Koenders from Citi again. Pete, just two quick questions, you spoke about the first six to nine months setting out the right path for investors next year about the project concept, how do you think that timing then ties into feed? Do you think feed is part way through that six to nine months?

Peter Botten: Look, feed for the next phase of development will be as early as possible in 2018 as we can achieve. The upstream feeds or pre-feed is largely completed.   We are no going through the optimal development phase of what we could build and I think that will be based on about a 3 million tonne commitment from PNG LNG for extra volumes, combined with maybe between a 5 million tonne and 6 million tonne capacity for Elk-Antelope.

Now the important engineering work that Chiyoda is rolling out to us right now is being rolled out in Yokohama as we speak. Frankly, I have not had an update as to what Chiyoda's years of life are on that and the size and shape of two train development and the options we have around that. But I will undoubtedly get that by close of business tonight and we'll be talking about that in the market I'm sure early in the New Year. Now that's a fundamental platform, is it a 6.4 or is it 5.4 plus a 3, how does that relate to existing facilities, what existing facilities do we use, et cetera?

So there is a focus, a very strong focus right now, on getting the downstream right so that we can then move in principles of sharing, high level principles of sharing into detailed levels of sharing. Equally, from PNG LNG's perspective we clearly have focused on where does the gas come from for the first few years of let's say a 3 million tonne capacity. We're focusing on the downstream, how gas from the Highlands can be mixed with gas from Elk-Antelope, they are different in terms of their composition, and in reality we're flat out.

These projects will happen when they happen, but at the end of the day everything we believe is happening or need to happen to get to a feed decision, I think early works is likely before middle of the year. The critical path is slightly different in expansion because I think we're going to be working very, very hard to get a gas agreement done before feed starts. I think that negotiation and discussions with government is the right determining step. So, look, I don't think there's a movement in any real sense in terms of timing, but again, I genuinely - we believe we'll get to FID sometime in 2019, and I'm very confident we'll be able to achieve that.

Dale Koenders: (Citigroup, Analyst) Then just a second question in a separate direction. As you've mentioned, you've got two Tier 1 assets, you said everyone is running flat out at the moment, it's definitely a very exciting time ahead for Oil Search. You've also mentioned you've got over $1 billion capacity on the balance sheet, are you looking for more assets or is now the time to really unlock the values in what you've got?

Peter Botten: No, I think to be honest I think we're full. We're full in terms of capacity, we're full in terms of our ability. We think we've got a great set of assets, we're very focused now on delivering long term value, I don't think we're - the new venture business generally speaking has been curtailed. But I can't emphasise enough that we absolutely want to see the road to commercialisation beyond 3 and 4, and if we don't see that coming to fruition, or don't see that clearly, then we will be attenuating our exploration programs until we do see that.

So already we've had discussions with Total and Exxon around that, how we can share exploration in the Gulf and do that. That is a critical, strategic issue for us in 2018 and drives a very strong discipline about where we spend our money and the timing of when we spend our money. I mentioned already, although not all of it is ours, 20 tcf is still remaining to commercialise in PNG. Now they're in disparate fields, in different areas, some are more remote than others but at the end of the day, optimising our next phase beyond 3 and 4 is a core strategic issue for us and will drive capital and capital prioritisation.

Unidentified Participant: Good day, Peter, just a couple of quick questions. What is it costing you to run the head office in Alaska, just sort of like an approximate G&A, and then…

Peter Botten: I think the number that I saw in set up costs was $30 million and maybe a bit less than that but G&A is not large.

Unidentified Participant: [Inaudible question - microphone inaccessible]

Peter Botten: I must say that our corporate budget for next year sees our corporate budget flat.

Unidentified Participant: Okay, and there was a slide that Keiran showed just on the development timetable for Alaska, I think we heard two year, 2021, 2022, drilling and build? Has that got a contingency built in say for weather? I mean I know you said you've got all weather access but…

Keiran Wulff: Sorry, Pete. The first thing that will be done there will be actually building roads so that you can support a year-round drilling. So as soon as you make an investment decision, the key there is to build roads, so you've 365-day-a-year drilling operations and you're remembering that all of those wells have been located from the same well pads, effectively three well pads, so you're not moving the rig, it's just a continuous drilling program. But what you will see is a progressive build up over time to the maximum production rate, you won't see that day one.

Unidentified Participant: Sorry to be an oxygen bandit, just one other thing. Just - and it sort of follows on from the back of Dale's question. You've got alignment in Alaska with Repsol, can you see that perhaps being templated back into PNG, given your previous comments on looking for other opportunities within PNG, given that 20 tcf is spread over a number of different fields, have you got some views on that?

Peter Botten: I think we've got pretty good alignment with both Exxon and Total, and actually between the three of us I think we're all working on the detail which will allow us to bring that alignment together in to more trains and then an alignment beyond that with maybe 4 and 5. I genuinely don't want to see our share of let's say in Muruk sitting for 20 years while we've got use of the capital elsewhere that can bring it to commercialisation much quicker. But actually, having sat down with these guys in the last two weeks and most recently on Tuesday, there's actually pretty good alignment.

We do need the inputs on let's say, is it a 614 million tonnes that we build plus a 3 million tonnes, is it a - how much look alike versus new shape of LNG plant that we build? There's strong alignment around what the upstream can do, the question is really getting the engineering about what the downstream should look like. Then we can turn the in principle discussions about sharing into the detail, which is clearly where we're going and we need to get in front of government. The government will get the engineering reports and we're prepared to go to government very early in the New Year.

So I think that's going to be the trick and certainly a big focus. I'm more actually thinking, dare I say it, I think 3 and 4 is a given, as there is clearly always a question in big projects about the final timing of that but I don't think that's moving too far. But at the end of the day, I'm also very keen to understand what 5 and 6 can do and drilling for backfill in 20 years is not an effective way of using our funds right now, and getting a commonality about future commercialisation pathways in PNG for gas is clearly a high priority in our strategic analysis.

Okay, any more questions? I don't know whether there are any through the Web. Okay, well, thanks, everybody. Thanks for coming, thanks for sharing some time with us. I hope you are encouraged by what we're doing, certainly we're available for further questioning after this and thank you for your attendance.

End of Transcript