FINAL TRANSCRIPT

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PRESENTATION

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

Good morning everyone. My name is Chris Stavros. I'm Vice President of Investor Relations for Occidental Petroleum. I'd like to welcome all of you here attending in person, as well as those listening in on our live webcast to Oxy's 2010 Analyst Meeting.

Before we begin with today's main event, I'd like to briefly run through a few housekeeping items. First, I would please ask that everyone place their cell phones and BlackBerrys on vibrate or silent mode so we don't disrupt the audio portion of today's program.

Second, as safety is a top priority at Oxy, I would ask that you take a moment to recognize the nearest exit to you, and please note that here are two emergency stairwell exits located at the front of this room and behind the projection screens.

Lastly, I would like to draw your attention to our Safe Harbor Language and cautionary statement found in our presentation. Please note that today's presentation contains certain estimates, projections, and forward-looking statements which involve risks and factors that could significantly affect our expected results. Those risks and factors are cited in our SEC Form 10-K, and can also be found on our website at www.oxy.com.

Well we have a very large crowd here today, as you can see, a full house in fact. And as far as I'm aware we're not giving away any door prizes. Steve Chazen actually suggested that I tell everyone to simply listen in to the webcast rather than attending, but obviously nobody paid attention. But we're very humbled by your interest in the Company and the high turnout.

As you can see from the agenda, we have a very full program outlined for you today. More than four years ago we stood in this very room and confidently said that we had a project pipeline of high quality growth opportunities that would allow us to deliver sustainable oil and gas production growth of 5% to 8%, while maintaining top-quartile financial returns.

Well, we're proud to say that we were successful in delivering on those objectives. The members of our senior management team assembled to my left are here to share with you today how Oxy plans to accomplish its next set of objectives and goals, as well as to share their high level of confidence in our ability to succeed over the next five years and beyond.

Let's now turn to the main event. It's my pleasure to introduce Oxy's Chairman and Chief Executive Officer, Dr. Ray Irani. Thank you.

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Thank you Chris. And good morning to all of you, ladies and gentlemen. My colleagues and I are very, very pleased to be here in New York to inform you about our plans for Oxy's continued growth and profitability over the next five years. To begin with, I want to give you a brief overview of our plans, and the key topics that we'll cover in this session.

During the rest of our time here together this morning, five members of Oxy's executive management team will discuss these topics in greater detail. I hope that at the end of the session not only will you have a solid understanding of our strategic growth plan, but you will also share the excitement and optimism that we collectively have.

Our goal for Oxy has been, and will continue to be delivering top quartile total shareholder return, as compared to our industry peers. And over the last decade Oxy has achieved top quartile returns. Let me now share with you how we plan to continue to deliver top quartile performance over the next five years and beyond, and we believe in many, many years to come.

We anticipate annual production growth of at least 5% to 8% from projects we have in hand. We also will maintain our intense focus on returns. We will target returns on investment of 15% after tax for US assets, and 20% or more after tax for international projects.

Increasing the annual dividend will continue to be an important part of our strategy going forward. And along with strong returns and dividend growth, we are committed to maintaining a low level of financial risk. We will also continue to emphasize our health, environmental, and safety programs. Oxy is one of the top safety performers in the oil and gas and chemical industries, and consistently ranks among the safest companies in the United States.

At the close of 2009, the United States accounted for 64% of our worldwide proven reserves, and 53% of our worldwide production. As we look forward, we intend to spend the bulk of our capital in the United States, including acquiring properties for expansion and growth. 73% of our proven reserves are in oil, and 27% natural gas. We intend to maintain our focus on oil, but our exposure to natural gas is significant and substantial.

While in the short term to the intermediate numbers of years we anticipate weakness in natural gas prices. We expect prices to improve during the next five years, and our strategy contemplates using that increase in pricing down the road. And we have built therefore a deep inventory of US assets with substantial natural gas reserves, which would allow us to take advantage of the improved long-term market conditions.

The Middle East Region will continue to be an important growth area for Oxy. We look forward to further increasing our presence there, working with partners to capture additional projects well suited to Oxy's expertise and experience in the region.

Oxy's worldwide production over the last five years consistently increased, with a compound annual growth rate of 7.9%. As you can see in the next slide, in addition to our most recent five-year results, we've added our projected worldwide production for the next five years.

Our US production is shown in green, our international production is in blue, and our expected output from Iraq, which I'll discuss in a moment, is shown in the blue crosshatched areas. The yellow area indicates additional opportunities we anticipate from existing assets, and you'll hear about that later on in the program.

As the graph indicates, we believe that Oxy could achieve average annual production growth of between 6% and 9% over the next five years. Conservatively, we are confident in achieving a production increase of 5% to 8%, consistent with our production growth over the past five years.

However, production could grow even in excess of 9%, depending on success in our exploration and development program, which you'll hear about later on. I want to emphasize that these projections are based entirely on performance expectations for our existing properties, and not from future asset acquisitions or new projects.

I mentioned earlier that the Middle East is an important growth region for Oxy. I want to call your attention to some of the most promising areas of opportunity for us in the future.

First, in Abu Dhabi, with the approaching expiration of numerous contracts in the emirate in 2014, we anticipate significant opportunities. The contract expirations will make more than 1.5 million barrels per day available for potential participation. And in light of our strong regional performance and effective working relationships, we're optimistic that Oxy will grow its business in Abu Dhabi.

Next, in Oman we've had great success in applying our expertise in enhanced oil recovery to maximize production, where other companies have delivered far less. With great success we've had at the Mukhaizna Field in south central Oman over the past five years, we have gained the trust of the Oil Ministry and other government authorities. As a result, we are confident that in the coming years we will have additional projects to produce oil and gas in Oman such as [competent].

In Iraq with a strategic location and best natural resources, the Western world will not allow it to become a failed state. In our view, Iraq with its reported 115 billion barrels of crude oil reserve proven, third most in the world, represents significant opportunity for us. As part of a consortium that will develop Iraq's, giant Zubair, oil field, we have what we believe is an important toehold investment in a project that will deliver solid returns.

We believe that over the next several years Iraq will evolve, building its infrastructure, achieving greater political stability, and strengthening security. As that occurs, there will be increased opportunity for those companies that have built relationships and performed successfully in that country. And as Iraq's regional stability further develops, we see potential for additional Oxy projects, particularly in the Kurdish area in the north and in the central area of the country. We do believe that Oxy will be both a key contributor and beneficiary as Iraq reclaims its important place in world energy production.

I will now give you a preview of the presentations to follow, which will provide you with new and detailed information about the topics I have mentioned. Some of what you will hear today has never been shared outside the Company.

First, you will hear from Sandy Lowe, our President of our International Oil and Gas Operations. Among other areas, Sandy will update you on our Latin American operations, and those in the Middle East. Next Bill Albrecht, President of US Oil and Gas Operations, will discuss our deep inventory of domestic drilling projects, and give you an overview of Oxy's significant position in the Permian Basin of Texas and New Mexico, including our growth in Co2 injection for enhanced oil recovery. Bill will also give you an overview of our substantial California assets and opportunities, as well as look at our mid-continent primary gas unit.

Anita Powers, our Executive Vice President for Worldwide Exploration, would provide you what I know has been a much anticipated detailed overview of our conventional exploration program in California, where Oxy is already the number one natural gas producer and number two oil producer, and we also are the leading acreage holder in the state.

Then you will hear from Todd Stevens, Vice President, California Operations, who will discuss unconventional plays in California. This is a very exciting exploitation area for us, and I believe you will find it particularly interesting. As you will hear from both Anita and Todd, we see tremendous upside potential in California from both conventional and unconventional projects.

Finally, our President and Chief Financial Officer Steve Chazen would conclude the session and provide further details on our financial and operational strategy for Oxy's continued growth. Following Steve's presentation we'll then have time for your questions. I'll now turn this podium over to Sandy Lowe to give you the details of our international assets. Sandy.

Sandy Lowe - *Occidental Petroleum Corp. - President - International Oil & Gas*

Thank you, Dr. Irani. Good morning ladies and gentlemen. As you can see on our map, we're in two regions, Latin America and the Middle East. I'll take you on a tour of our producing areas. First we'll go to Latin America. Our 2010 outlook is 79,000 barrels, average per days 2,014. We expect to be between 95,000 and 105,000 barrels a day net production to Oxy.

The first country we'd like to go to today is Columbia. On the right hand side of your screen you'll see the Cano Limon field in the Llanos Basin. That's where we started in the early 80s. We have three billion barrels of oil remaining in place in that field and its associated trend. We're going to drill 15 more infield wells in Cano Limon this year, but we also have what we call the new fields that are on the same trend.

There are a number of those various different names, and we've been pleasantly surprised with some stratigraphic reserve upsides in some of these fields. We're going to drill two more of those this year. Our gross production this year is going to be 80,000 barrels a day, with a net of 23. In 2014 our gross drops down to 33,000 and our net drops to 10.

However, here on the map in the middle of Magdalena Valley we have the La Cira Infantas field which we went into partnership with Ecopetrol four years ago, and we've been able to raise its production from 4,000 barrels to 26,000 barrels a day today. There's 800 million barrels remaining in place in these fields.

We continue to have an aggressive development of 150 wells this year, and we'll be increasing water injection facilities substantially. In 2010 from these fields we expect to have 28,000 barrels gross a day with a net of nine, and by 2014 we expect that gross to get up to 50,000 barrels a day with a corresponding net of 18. So for total in Columbia in 2014 our net is projected to be about 28,000 a day.

Going further south to Argentina, we have three producing areas. But as you see in the chart, most of our fields are actually in the Santa Cruz province, 15 of them, and most of the production comes from those 15 fields. The inset on the right hand side shows you those 15 fields shaded in green. The San Jorge Basin is about 1,000, 1,200 miles south of Buenos Aires.

We have 6 billion barrels remaining in place in Argentina. We currently operate 2,200 wells. 85% of this is oil, 15% is gas. We have 26 waterfloods and 13 gas plants. Our plan this year has been to focus on getting an extension for 10 years to our Santa Cruz concessions. I'm happy to report, as you've probably seen, the governor of the province has signed up last week.

We expect the legislature to meet next week and ratify this. We'll talk a little bit more about that on the next slide. This year we expect to bring production up 8% over last year. We are going to drill 140 wells and perform 100 workovers. We'll continue to add waterflood facilities. We're expecting gross production of 50,000 a day this year and 45,000 net.

So this contract extension brings these fields to an expiry of 2025. This gives an opportunity to fully develop and exploit these prolific reservoirs. We plan to continue production growth at 9% a year through 2014 and beyond. We're going to perform near field, low-risk exploration, step-out wells at about 10 wells a year. We're going to drill 140 development wells every year, and we're going to focus on continuing to add waterfloods. In 2014 we expect our gross to be between 74,000 and 85,000 barrels a day with a corresponding net of 65,000 to 75,000.

Let's move to the Middle East. Our outlook for this year in the Middle East is 286,000 barrels net to Oxy. Our outlook in five years is 358,000 to 381,000 barrels net.

We'll start in Libya. Our concessions still have 7 billion barrels remaining in place. The Nafoora Augila Field is shown in red. It will get 255 new wells over the next three or four years and 32 workovers. We'll install a million barrels a day of processing facility both for oil and water injection and 100 megawatts of power.

The Zeuitina fields, the legacy from Oxy in the 60s and 70s, are shown in the yellow, and they'll have 96 new wells and about half a million barrels a day of processing facilities. For the next three years we expect to have 22 exploration wells. This year we expect our gross to be 98,000, our net to be 15,000. In five years, in 2014 we expect the gross to be up to 160,000 to 172,000 with a corresponding net of 28 to 33.

Let's move to Yemen. We have over 2 billion barrels in place remaining in our Yemen concessions, and I'll point to the map if I can. In block S1 on the left we have 9,000 barrels a day production.

In the East Shabwa in block 10 we have 60,000 barrels a day of gross production, and in block 14, the Masila block, we have 71,000 barrels a day. The Masila contract will expire at the end of next year, but the extension is currently under negotiation. Our program this year is 31 development wells and three exploration wells. In 2010 we expect a net of 30,000 barrels a day. By 2014 we expect to have a gross production between 75,000 and 110,000 and a net of between 16,000 to 24,000.

Let's go to Qatar. Looking at the map, we operate three oil and gas fields here, Al Rayyan up to the north, Idd El Shargi's North Dome, and Idd El Shargi's South Dome.

I'll talk about the Dolphin Gas Project, which is part of Qatar, in a minute. The 2010 gross production is expected to be 118,000 a day with a net of 76,000. Our priorities in this country are to maintain this level of production from these existing fields, and we expect to have some additional activity and increased production later in the five-year period.

The Idd El Shargi North Dome development is all about enhancing production by applying modern technology. We today enjoy a gross production of 105,000 barrels a day.

We took this field over in 1994, and immediately employed extensive horizontal drilling, which was relatively new at the time. We knew we had to waterflood a very tight matrix reservoir, and we figured out how to do that. We employed multilateral production, that way we'd have three or four locations for completion and going up one (inaudible) which was the cost-effective way of draining this reservoir. And we were also an early user of multi-laterals for taking source water from one aquifer, using an electric pump to pump it over to an oil producing dome without coming to the surface. This allowed us to get production up and keep it up.

I talked about continuing to develop and invest. We broke our project into four phases. In the first seven years we drilled 77 wells. We added gas lift and water injection. The second phase is 2002 to 2005, we built another 50 wells and we added more power, gas compression, and water injection. In the first two phases, and I'll show you a picture in a minute, we added most of the facilities we need, after that it's mostly been drilling.

In the third phase, just finishing this year, we drilled 70 more wells. And the fourth phase for Idd El Shargi North Dome, but also some additional work in the South Dome in Al Rayyan taking place this year, next year, and the following year, we'll drill 55 additional wells, add two more platforms, some more power, some more minor bits of facilities, and we'll develop 70 million barrels of gross reserves. By 2014 we expect to be having a gross production of 100 to 110 with a corresponding net of 65 to 70.

This is a picture of the history of it. But before I explain it let me just say this is offshore, it's very shallow water, very low pressure, and there's no resemblance to what you're hearing on the news or reading in the paper these days. In 1964, on the top left this is a platform that Shell put out there when they were in charge of this field.

In 1994, on the bottom right this is how it looked when Oxy took over. That little platform is still there. And today you'll see we've added platforms all around the edges of the complex, and we've added 15 more platforms. But as I said earlier, we're kind of finished with the platforms. We're just going to continue drilling and working over, and hopefully keep our production up for many years to come.

I think this graph truly tells the story of Oxy in Qatar. In 1987 you'll see this is where Shell handed over to Qatar Petroleum, and they had some modest successes there. We took over in '94 and as you can see, we ramped up very nicely. Back in the '98 period we knew we needed to figure out how to waterflood this type reservoir. So in here we installed the waterflood equipment, drilled the wells, and then as you can see, we ramped up again and we've held it up nicely since then.

I'd like to talk about Dolphin. I want to emphasize that Dolphin also starts in Qatar. The Dolphin gas fields are part of the North Field where most of the LNG comes from. We bring it ashore to a gas plant in Ras Laffan. This was the biggest initial build gas plant ever built. It ships 2 billion cubic feet a day to the UAE markets, 200 million cubic feet to Oman. The pipeline on the map is the longest large diameter pipeline ever built for subsea use. The big pipeline shown in red-orange on the map, or the actual distribution trunkline, there's some 30 other distribution pipelines within the UAE, that's important because I'll explain to you about income that we earn from our midstream in this area.

The gross production this year's expected to be 530,000 barrels of oil equivalent a day. That includes over 100,000 barrels of condensate and several thousand tons each of propane, butane, and ethane, in addition to the gas. Our yields from these fields have been consistently above our gas and liquid production that we anticipated at the start.

We've always shipped a little bit of third-party gas, this pipeline is rated at 3.2 billion a day. More recently we've come up with some new programs to ship up to 400 million a day which could grow, and that gas will be marketed inside the UAE. This project was somewhat unique because it was just about on time and very close to being in budget in a period when none of our peers could say that. And we've enjoyed exceptional returns on this project.

This is one picture of the flap. The Oxy share is 24.5%. 51% of this project is owned by Mubadala, which is the investment arm of Abu Dhabi. Our 2010 gross production is expected to be 537,000 barrels of oil equivalent per day with a net to Oxy of 64,000. The fee income that we gained I'll show you on the next slide. The 2014 expected gross is 535,000 but the net drops to 39. This is a pretty much standard production sharing contract. We will reach cost recovery in 2013, hence our take is reduced. However, we built up a nice dividend fee income, and this year and last year we're getting about $125 million a year, rising to 150 by 2014, and will rise long-term to 175 or more every year.

Let's move to Oman. We started operation in Oman in 1984, and let me just show you what I'm going to talk about. We'll talk about the Safah Field in block nine, and then we acquired bock 27 which is next door. We've recently acquired block 62 which is four gas fields and some deep prospect. And then we'll talk about Mukhaizna in block 53.

We've drilled over 500 wells in block 9 and 27, and we've discovered 30 additional oil fields. We acquired Mukhaizna in 2005, we acquired block 62 in 2008. We've drilled over 1,300 wells in Oman total. This year our expected gross production will be 190,000 barrels a day and our net will be 70,000 barrels a day. In 2014 we expect to gross between 220,000 and 240,000 and a net between 70 and 80.

I think this graph tells you our story. We started off in 1984, we had a reasonably nice ramp-up. At the end of the century we figured out we better put in a waterflood, and we did that, ramped up again, and as you can see, we've kept it up nicely. In fact today, they're at 91,000 barrels a day, which is a record. The blue bars on top indicate what we're doing with Mukhaizna, which I'll talk about in a minute. This is all gross production.

A little bit more on blocks 9 and 27; we have over 2 billion barrels still in place in these blocks. The gross is currently at a record, as I said. But we're still doing exploration. We expect to do a lot of near field, low risk step out type exploration. We've added 50 million barrels gross reserves over the past five years. We still have a multiyear inventory, and we expect to discover about 10 million barrels gross per year for the next several years.

Maradi Huraymah and Habiba, Fushaigah, and Rasafah. Again, we're partnered with our friends Mubadala and with Oman Oil Company. Our first task is to develop the Maradi Huraymah field which has already been appraised. This year we have five appraisal wells, two of which are already drilled in the Habiba prospect, and we have encouraging logs and cores, and we expect to be doing tests in June.

For 2011 onwards we have more exploration, two more shallow wells, the three to four deep wells, deeper than it has been drilled in this area, 15,000 to 20,000 feet. We believe the deep potential is 1 trillion to 2 trillion cubic feet.

Let's talk a bit about Mukhaizna. Mukhaizna is 14 degree API. It doesn't flow unless it's heated, or it flows very slowly. So what we've done is put in a world class steam flood, 600,000 barrels a day of steam. There's over 2 billion barrels remaining in place. It was discovered in 1975. The coal production started in '92, coal production is a very low flow situation. We took it over in September of 2005, started up the steam flood in May of 2007, and today the gross production is actually 102,000. It's been running over 100 for most of the past month. Our target production is still 150,000 barrels a day gross.

I guess if you were here four years ago we showed you a picture of the desert with nothing. And now we have several good pictures to show, but I could only put one. Steam floods without water, there's no easy water in the desert.

So we take water from aquifers below Mukhaizna, water that's contaminated with dissolved solids. It's no good for drinking, it's no good for irrigation, but we have to condition it. We use these devices shown in the picture, they're called mechanical vapor

compressors. These are the largest ever built, built in Pittsburgh. And they condition 300,000 barrels of water to boiler quality feed water every day. We're going to double our water supply and get up to 600,000 in the next two years.

Let's move to Bahrain. Our development plan in Bahrain has us increasing from today's 30,000 barrels a day up to over 100,000, and today's gas sales from 1.1 billion a day to probably over 2. By 2000 -- yesterday in the press I read it's going to be 2.7, so it's going to be nice.

The gross oil production for 2014 is expected to be between 70,000 and 75,000 barrels a day, and the gross gas expected to be 1.6 by 2014. Let me just remind everybody where it is. The Kingdom of Bahrain is nestled between the Kingdom of Saudi Arabia and the State of Qatar. The Bahrain field, which some of you may know as the AWAI Field, takes up most of the island. This field still has 7 billion barrels remaining in place. It still has 17 trillion cubic feet in place.

We have a joint venture company, we lead it, and our friends with Mubadala are with us, and Nogaholding which is an entity of the government of Bahrain. We have 19 reservoirs that are shown here, and we're going to produce all of them. The two at the bottom are gas, the [Kuf] formation. But below the Kuf is what's called the pre-Kuf 1,000 to 4,000 feet below that. And we're currently short-listed for the exploration contract for that particular pre-Kuf formation.

This field redevelopment is a big drilling project, 2,500 wells. We've added one modern rig very similar to the ones we're using in Oman, Argentina, Columbia, and here in the United States. We're going to add five more of those and we're going to add six modern workover rigs. Then we're going to get after the process of waterflooding, but also steam injection. And we will steam inject these fields very similar to what we're doing right now in Mukhaizna. And then the rest of its increasing capacity for everything, the fluid handling, gas handling, tanks manifold, steam water, and gas processing.

Let's move to Iraq. Let me just orient you before we start. The Zubair Field colored in yellow, we're in a joint operatorship. The contractors in that operatorship are ourselves, ENI, and KoGas. The fields around us include most of our major competitors, Exxon, Shell, Petrobas, Chinese, the French. And these guys are all joining together with us for some common facilities, which we think is a good idea. The first facility we're going to join in on is 10 million barrels of seawater injection.

You may have read in the press that we were going to take drinking water to use for water injection, that is not the case. We're going to bring seawater in and waterflood all these fields from the same source. We also expect to work on common power generation and common export and terminal facilities.

Oxy signed our agreement in January of this year. This agreement allows us to produce oil, take payment in kind, and book reserves. As you probably know, there's a lot of oil left in this field, over 20 billion barrels. The gross production we expect to be at 200,000 by year end, and we expect to get to 1.2 million a day in seven years. The base rate today, which is a contractual measured rate is 182,000 barrels a day, and we've submitted a rehabilitation plan that will cover the years 2011 through '13.

Some features of our contract. This contract allows for quick cost recovery. At today's prices payback occurs in four years. It takes less if the price rises. In other words if we put $800 million -- $800 million is out maximum cash outlay at any one time, and we would get that back in four years from investment. Our ultimate recovery net to Oxy is expected to be 210 million barrels at today's prices.

Today in Iraq we have 40 people now, 150 by year end. About half of these would be in Basra, half would be in the Zubair Complex, and three or four would be in Baghdad at any one time. Most of these people would be on rotation. We're forming a consortium, the three contractors and the south oil company which is an Iraqi entity that has essentially been operating this field for the past 30 or 40 years. We will form what's called the Zubair Field Operating Division.

We anticipate Zubair will get its 10% growth to 200 gross a day by the end of the year, and that the rehabilitation plan will be approved by the end of the year, both of which are necessary in order to have our cash register start ringing and start our cash

flow. By 2014 we project that our gross production will be 840,000 to 880,000 barrels a day. Our net corresponding to that to Oxy is expected to be 65,000 to 75,000 barrels a day.

To recap the numbers, we expect to have 365,000 barrels a day net this year for international. By 2014 we expect that number to rise to 453,000 to 486,000 barrels a day. So the summary for the international group for the next five years is to grow.

We'll grow Oman's gross from 190 to 240, we'll grow Bahrain's gross oil from 30 to 75, Bahrain's gross gas from 1.1 to 1.6 or more.

In Argentina we'll grow the gross production from 50 to 85, and Iraq's gross production from 182,000 to 880,000 barrels a day. During these five years we will continue working to generate substantial free cash flow from Qatar, Dolphin, Columbia, and Yemen. Thank you very much.

Bill Albrecht - *Occidental Petroleum Corp. - VP, President - US Oil & Gas*

Thanks, Sandy. Good morning. My name is Bill Albrecht, and I am responsible for managing Occidental's US Oil and Gas Operations. And as such I'll be briefing you on those operations this morning. And what I'd like to cover are our three main business units, that being the Permian, where I'll talk about primary development drilling activities, as well as future opportunities for growth in our CO2 operations; California, where I'll touch on our flagship asset, which is the Elk Hills Unit, and other significant fields across California; and then in the Mid-Continent, where our two primary pieces of business are located in the Piceance Basin of Colorado and in the Hugoton.

I'd like to begin with the Permian. The Permian is Occidental's largest business unit. We currently produce some 180,000 barrels of oil equivalent per day out of the Permian. That makes Oxy the largest oil producer in the state of Texas, and obviously the largest oil producer in the Permian. We produce fully 20% of the Permian's total oil production.

We're the largest operator in the Permian of the more than 1,500 operators that are located there. And each month we pay more than 10,000 interest owners, either working interest owners or royalty owners out of the more than 75,000 interest owners that are located throughout the Permian.

And what I think this begs, or it makes obvious is the fact that this is a natural area for continued consolidation. And we've had a pretty good track record in the past of consummating both on acquisitions to add to our Permian portfolio. It's a big area, 100,000 square miles. We've captured more than 2.2 million net acres.

We have more than one-third of the Company's total net proved reserves residing in the Permian, some 1.1 billion barrels of oil equivalent. And we handle 1.7 Bcf a day of Co2 out in the Permian, or a half a Tcf per year, and that makes us the largest handler of Co2 in the world.

I'd like to now talk a little bit more about our two tranches of growth opportunities, beginning with primary development. This year we're going to be focused primarily on our Southeastern New Mexico and Southwestern Texas assets, continuing exploitation there primarily in the Delaware and Bone Springs Sands.

We're also going to be concentrating on an emerging Wolfberry play in and around our Dora Roberts ranch unit, which just for locator purposes is located about 10 to 12 miles south of the Midland-Odessa airport. And we also have some deeper oil plays, primarily in the Devonian and in the Ellenburger where we currently have one rig running in each of those horizons.

In terms of Co2 growth, could be talking about some existing flood expansions across a number of our legacy fields, and also expansions to what we call the residual oil zone, which is located beneath most of our Legacy Permian producing properties.

We've got new Co2 projects captured, and we're going to be continuing with infield drilling and pattern regularization on those particular projects. And then of course many of you have heard about the new Century Co2 plant that's scheduled to come online sometime this year, late 2010. And that of course will be providing us some additional sources of Co2 supply.

Just looking a little bit more closely now at our primary development drilling opportunities, I mentioned both the Delaware Sands and the Wolfberry play and you can see that those are encompassed here by the ellipses on this particular slide.

And also I want to mention that we do have some new emerging plays that are coming our way that have been historically uneconomic, but with the advent of course of horizontal drilling and stronger commodity prices, these are now economic. A good example of this is the Bone Springs. In fact last week we just IP'd a Bone Springs well for north of 1,500 barrels a day. This was a long reach lateral, but that is definitely an emerging play for us.

Also, I mentioned those deeper oil plays in the Devonian and in the Ellenburger. We actually have one rig running right now in each of those particular plays. And we've got Morrow Sand, these are gas opportunities that are located in the southeastern area of New Mexico. And the good news is, is that all of these deeper plays are on acreage that we currently have in hand.

So to sum up our added plays inventory, we've got about 1,000 locations that we think will bring us, and this is a net risk reserve basis, some 100 million barrels of oil equivalent. Our infield drilling inventory is very robust. In fact we've got a greater than 10 year inventory of infield wells to drill at our current drilling pace. And I mentioned the higher oil prices that are bringing these new opportunities to bear, and a good example of that is this Bone Springs play that we're currently in.

I'd like to move now into Co2. And I think this chart is pretty indicative of the robust growth that Co2 has enjoyed throughout the Permian. If you look back, in 1982 there was about 25,000 barrels of oil per day of production related to Co2. That number today is right at 200,000 barrels of oil per day, and Co2-related operations throughout the Permian account for about 22% of the total Permian oil production today.

Now in terms of operators of active Co2 floods, clearly we are the 800 pound gorilla here. We operate 28 active Co2 flood projects, which is more than all the other Co2 flood operators in the Permian combined. And commensurate with that operatorship of the most flood projects obviously is production. We produce between 85,000 and 90,000 barrels of oil per day related to our Co2 operations, which is roughly equivalent to all the other operators there combined.

And if we look a little bit more closely at our Permian oil production, fully 60% of our current production is related to Co2 projects. We've got another 30% under waterflood, and only 10% is under primary producing conditions. We've got 28 active flood projects, as I mentioned. But in the past, a limited Co2 supply has really impacted our production, and it's restricted our ability to move new projects forward. So we believe, obviously, that there is a significant growth opportunity remaining here relative to our CO2 operations.

I'd like to share with you just some examples of Co2 flood response. And I think this is pretty telling as to how successful these projects are. I want you to keep in mind that these projects, some of which are examples of smaller Co2 floods, and some of course are just parts of larger CO2 flood projects. What I've done is I've taken the water off of these curves and I'm showing oil in green and CO2 injected in red.

The first example here is in one of our Legacy fields in the Slaughter Estate. It's the San Andres flood and the San Andres flood located in the northern part of the Permian. And you can see here how the base decline rate has been shallowed and somewhat arrested.

Over on the western side of the Permian is the North Hobbs Unit. This is another Grayburg San Andres flood. It's what I call -- it's an example of a fast flood, what we saw an almost immediate oil response to Co2 injection. And in fact here we enjoyed a doubling of production once Co2 injection began.

On the far eastern side of the Permian is the Cogdell Canyon Reef Unit. This is not a typical Grayburg San Andres flood, it's a Canyon Reef flood. But this is another good example of what I call a fast flood. And here we saw a tripling of production in response to Co2 injection.

And then last, down in the southern part of the Permian is an example of a Devonian Co2 flood. This is actually a secondary Co2 flood, it's never been under water flood. And it just shows you an example of how increasing slug size, which is just an increase in the hydrocarbon-four volume injected, how that has impacted oil production in a positive way.

If you looked at all of the Oxy operated Co2 floods and you asked me, well what is the average response time that we might see to Co2 being injected? I would tell you that on average it's one to two years. And before I move off of this slide, there's a couple of key takeaways that I would like for you to have from this. And the first is that response to Co2 injection is pervasive. It works northeast, southwest, no matter where you are in the Permian.

And the second key takeaway is that it's applicable to many different reservoirs, not just the Grayburg San Andres that so many of you have heard about. We've shown you some successes here in Canyon floods as well as in the Devonian.

Now I want to take just a minute and talk a little bit about Co2 surveillance. You know, traditionally we had very customized, I would call them customized parameters on a flood by flood basis. And it meant that CO2 surveillance was a very time intensive process, and it was one that frankly only our most senior reservoir engineers were good at.

And so we felt that in order to better survey all of our CO2 floods we needed to go to something new. And so what we did is we instituted a standardized approach, using some special visualization software that now allows us to do monthly surveillance updates on the more than 1,800 Co2 patterns that we have throughout the Permian.

We actually evaluate 50 parameters for each and every pattern of all of our Co2 flood projects. And this is something that now our junior engineers are doing because it's a standardized process across all of our flood projects. And what this has allowed us to do is reallocate Co2 to better performing patterns. And just here recently we've been able to enjoy at least a 3,000 barrels of oil per day improvement with no additional volumes, no Co2 being injected. It's just simply a better allocation and more efficient use of our Co2.

So what is the remaining opportunity here for Occidental? Well I asked our Permian base and business unit to go back and calculate the net original oil in place, not the gross but the net original oil in place underneath all of our actively operated Co2 flood projects, 28 or so of those. And what we found is that we had 11.9 billion barrels of oil in place.

Now we've produced 4.1 billion barrels of oil to date from these projects, but that still leaves behind a huge number, 7.8 billion barrels of oil net remaining. We've only got 800 million barrels of those booked in the form of 3P reserves, and I believe it's very likely that we'll recover an additional 1.4 billion barrels on top of that. And I think it's reasonably likely to expect that we'll produce another 1 billion barrels of oil on top of that.

So if you look at the right hand part of the pie here and you add these numbers up, and you add that to our cumulative production on our Co2 flood projects, primary, secondary, tertiary, recovery, you get north or right at a 60% recovery factor. And I can tell you that on four or five of our more mature Co2 flood projects we're approaching that recovery factor already. So that's why I say I think it's pretty likely that you'll see recoveries approaching 60% of the original oil in place on our Co2 projects.

So now let's talk about the next billion barrels. How much Co2 is going to be required to produce the next billion barrels of oil out of the Permian under Oxy operated projects? And we think that number is about 5 Tcf. So if you do the simple math here and ratio, the number of MCF to the number of barrels recovered, you get a five-to-one ratio. And I can tell you, that is a very favorable ratio. On a net basis we're normally looking at numbers 6 to 8 MCF net to be injected per barrel of oil recovered. So we think that the five-to-one ratio is certainly very favorable. And I think it just attests to the quality of reservoirs that we have.

Now where's this 5 Tcf of supply going to come from for the next billion barrels? Well as I mentioned earlier, we currently produce 1.7 Bcf per day, or a half a Tcf a year. Now we've got 1.1 Tcf currently captured under current purchase contracts, and we obviously have more opportunity to purchase additional Co2. And a good example of that is that we're currently contracting for another 100 million a day of CO2 over a five year period, or that's about two-tenths of a Tcf.

And we produce, or we have captured 1.6 Tcf from our own Co2 source, that being the Oxy operated Bravo Dome Field which is located in the northeastern part of the state of New Mexico.

And this is an area that we can easily throttle up Co2 production simply by drilling more wells. We have lots of running room remaining in Bravo Dome. And then we also have additional Co2 supply in the form of methane CO2 fields located in the southwestern part of the Permian. This is in and around where our Century plant is being constructed. And that number is 3.5 Tcf. So obviously, you add up all these sources of supply, you get about 6.2 Tcf, more than enough to certainly produce the next billion barrels.

Now, I think one of the questions this begs is the Pinon Field which is located in and around the Century plant. And the question is what happens if Pinon development ceases? Well we believe that there is currently developed Co2 available that would be available to Oxy at similar rates.

And if the Century plant delivery schedule is not met for whatever reason, we think that there is adequate Co2 supply today on the market to cover that shortfall, and any penalties that would be paid for those non-delivered volumes would effectively offset, or largely reduce the cost of any makeup CO2 that we would be required to purchase to make up for that shortfall. And we obviously expect to be able to secure such additional supply, should it be necessary.

I wanted to show you this snapshot of the Century plant. This shows Train I under construction. It's about 95% complete, Train II is about 25% complete. The plant's designed for a raw inlet gas stream of 675 million cubic feet a day, and we're expecting it to tailgate of Train I 260 million cubic feet a day of Co2, and to tailgate of Train II another 180 million cubic feet a day of Co2. We're expecting to commission and start up Train I some time here in the fourth quarter of this year, and Train II should be on stream early in 2012.

Now where is all this Co2 going to go? Well, I mentioned that we have flood expansion opportunities across a number of our Legacy oil fields in the Permian, and I'm sure that a lot of these Legacy field names should be very familiar to you. And you'll note here on these flood expansion opportunities also, the residual oil zone. We've got a residual oil zone that's located underneath most of these Legacy fields that we have yet to fully exploit. And we believe that the greatest remaining potential for us for additional oil recovery is through the expansion of these existing Co2 flood projects.

These are legacy fields. Co2 has been injected in these fields for quite some time. There's a lot of running room left, and we know it works. So we feel very good about the flood expansion opportunities here.

We also have new Co2 flood projects captured in areas like West Seminole. Many of you have heard of the Seminole San Andres Unit. This is just a unit that is adjacent to that.

We have the Sharon Ridge field on the far eastern side of the Permian, which is another canyon reef-type field. I showed you an example of how well Co2 worked in analogous field.

The Clearfork, we must not forget about the Clearfork. We have Clearfork reservoirs under most of our Permian acreage. The Clearfork has yet to be Co2-flooded.

Then, of course, as I mentioned, slug size increases are just simply increasing the amount of Co2 as a percentage of hydrocarbon core volume. We've got those slug size increased opportunities across nearly all of our existing Co2 flood projects.

I wanted to share with you, what I think is a compelling cost structure slide on our Co2 operations. If we take a $75 per barrel marker price, WTI marker price, and we back out things like royalties, lifting costs, Co2 costs, production taxes, overhead and even amortized capital because, as you know, as you increase the volume of Co2, sometimes you need to do infrastructure improvements to handle the additional volumes of Co2.

But if you take all of those out, at a $75 marker price, we still generate more of a 50% profit margin on every barrel of oil that we produce relative to our Co2 operations. So obviously, this is a very profitable business for us.

So to sum up the Permian, I talked about primary development drilling, a very deep inventory in more than 2,000 locations currently identified. As you would surmise in the Permian, these are nearly all oil, and these locations are on acreage that we already have captured.

Our Co2 growth, 1 billion to 3 billion barrels of net enhanced recovery reserves that we are expecting will be produced from our operated Co2 floods. We've got a significant inventory of Co2 flood opportunities in the form of expansions, flood size increases, new projects and the residual oil zone beneath most of these projects, and now told we're expecting to grow our Permian production from the 180,000 barrels of oil equivalent that we're currently producing today to somewhere between 220,000 and 230,000 barrels of oil equivalent per day in the year 2014.

As Dr. Irani mentioned in his introductory remarks, this growth is going to come from existing projects in an area that doesn't include acquisitions, and this is an area where we had been very successful in consolidating additional interest and growing our production through acquisitions.

I'd like to turn now to California. We're currently producing 143,000 barrels of oil equivalent per day from our California operations. We have nearly 25% of Oxy's total net proved reserves residing in the state of California, some 780 million barrels of oil equivalent.

Our main producing assets are our flagship asset at Elk Hills. We also have a substantial asset down in the Wilmington field, which is in the Long Beach area. Then, we have other various assets in significant fields located throughout the San Joaquin, Ventura, LA and Sacramento Basins.

We're the number one natural gas producer in the state and number two oil producer in the state of California. I think very importantly, we have the largest fee mineral ownership position in the state of California with more than 1 million net fee mineral acres. We've got 90 producing fields, over 600 miles and some 7,500 active wells.

Now looking at Elk Hills specifically, just a few key facts. You might recall when we got into Elk Hills via an acquisition from the United States government in 1998, and we have approximately a 78% ownership in the Elk Hills unit.

Elk Hills in and of itself has some 538 million barrels of oil equivalent on the books as of year-end 2009, and that is fully 70% of the total of California reserves. We produced 400 million barrels of oil equivalent to date and achieved, on average, a 125% production replacement since the time that we have had Elk Hills.

Elk Hills in and of itself is the largest gas producer in the state of California and the largest NGL producer. It's also on a standalone basis the fifth largest oil producer in the state of California. We also have at Elk Hills the largest gas plant infrastructure in the state of California.

Looking at Elk Hills here near-term in 2010, what we're primarily focused on this year is our bread and butter standard Stevens sand and shale drilling and exploitation. We're currently planning to drill some 60 wells here to the Stevens sands and shales on the Elk Hills unit in 2010.

We've also refocused our effort on the giant eastern shallow oil zone that's located over the eastern half of the Elk Hills unit. We'll drill about 130 development wells there in the eastern shallow oil zone this year. To do this, it's going to take a seven-rig program, which is what we're currently running.

As far as location inventory goes at Elk Hills, we have some 1,760 drilling locations currently in inventory. I must tell you that I think that number is conservative because this location inventory just continues to grow year after year.

What happens is when we drill additional development wells, these development wells just set up more locations. So this drilling inventory has remained fairly constant over the last several years.

I'd like to mention now our gas plant infrastructure at Elk Hills. We currently have a 420-million-cubic-feet a day processing capacity at the Hill, and we are at capacity. We're full.

We're going to be installing a 90 million a day skid-mounted gas plant, should be on stream. We're in the commissioning process now, but sometime late here in this quarter. That will add 90-million-cubic feet a day of gas processing capacity, and we believe that once we get that facility commissioned and lined out, it also will be at capacity.

So what we have done is we have just approved expenditures for a cryogenic gas processing plant at Elk Hills for 200 million cubic feet a day to bring our total gas processing capacity to just north of 700 million cubic feet of gas a day.

I think this begs the question, "Well, how did you decided or why did you decide on a 200 million a day plant?" Well, we wanted to build the largest plant that we could build in a reasonable timeframe, and we thought that was a 20 to 24-month timeframe.

Just for timing and bracketing purposes, if you look at Dolphin, which Sandy mentioned in his remarks, the first 500-million-cubic-feet a day train at Dolphin took about 36 months to construct. So we believe that a 20 to 24-month timeframe for a 200 million a day processing facility is a reasonable amount of time.

Now we've already awarded the contract for the plant, and work has begun. What the plant I think is going to provide us is a deeper cut or a greater recovery of our NGLs coming through the Elk Hills gas plant infrastructure. It's certainly going to improve our gas sales quality, as we've got very tight gas sales specs to meet for gas that's coming off of the Hill.

It's going to be the largest, most efficient plant in the area. I think it's going to even bolster the fact that Elk Hills is really a regional gas hub. By the end of the year this year, we know we're going to have to order additional capacity, but we'll make that call at the end of the year as to how much additional capacity that we'll be adding.

I've got one slide in here on our Kern County discovery. Anita Powers, who will follow me, will certainly give you more color on this. But we currently have 24 wells that are capable of producing 45,000 barrels of oil equivalent per day gross. I say capable because, as I mentioned before on the previous slide, we are currently gas-plant-constrained here. Even when the 90 million a day skid-mounted facility comes online, we believe that we will still be gas-plant-constrained.

We're planning to drill an additional 20 wells this year, and we're going to mainly focus on oil because of the gas plant constraints and also because we've got a number of structural position oil wells to drill. So we're going to focus on oil this year, although there will be some associated gas produced for those oil wells.

We still have extension opportunities off this discovery to the north, south and west. We've currently got 30 additional locations on the books to drill beyond the year 2010. Like I say, Anita will give you more color on that in just a moment.

I wanted to touch on our North Shafter field, and you're going to get more color from Todd Stevens on unconventional oil reservoirs. But this is an unconventional play. This is an unconventional oil reservoir. It's an antelope shale reservoir that we got

in via an acquisition in 2004 where we acquired a 58% interest, and we just picked up the remaining 42% interest at the end of the year last year.

140 million barrels of oil equivalent in place, but as you see on the slide, a very, very low recovery factor. So obviously this lends itself well to down-spacing. What gets us even as excitement about this particular unconventional oil play is that we just completed California's first cemented liner per plug back and frac operation here at the North Shafter field, and we had excellent results, an IP of some 350 barrels of oil per day. We should be able to apply this technique across all of the down-spaced locations that we now are planning to drill.

I wanted to touch just briefly on our legacy heavy oil property at Kern Front. It's located just outside Bakersfield. You can see the graphic on the left in the rose color. That's where are historical steam development has been through the years.

We've got a fairly good proved undeveloped reserve inventory that's highlighted in the darker green. Then, in the lighter color is a very large probable undeveloped piece. I think what's exciting about this is that you see on the right we still have undeveloped reserves of some 42 million barrels of oil net to be recovered here.

We recently just attained a new Oxy monthly production high of nearly 8,000 barrels of oil per day from these operations. We're expecting to grow this by 25% over the next five years.

I'd like to move down south now to our Wilmington field. Wilmington, as many of you probably know, is among the top ten largest oil fields in North America with some 6 billion to 8 billion barrels of oil in place and about 2 billion barrels of oil have been recovered today, which just doing the simple math, that's a fairly low recovery factor for a field that has just matured.

So we believe that there is significant redevelopment upside remaining here at Wilmington. As you know, we currently operate on behalf of the state of California and the city and the port of Long Beach.

Now we've been able to steadily grow our field ownership over time. In fact, now we currently have a stake in over 80% of the properties that overlie the Wilmington field. We divide Wilmington into two pieces, the onshore piece, which we call Tidelands, which is governed under the terms of a service contract or a cost plus contract, and the offshore piece, which goes under the moniker of the THUMS Long Beach unit, which is governed under the terms of a production sharing agreement.

Now we recently were successful in converting the Tidelands service contract, or a portion of the Tidelands service contract, to a production sharing arrangement. We're in negotiations with the state of California to do likewise there. We have an opportunity, I believe here, to significantly grow our production in this particular field in the future with, of course, some added investment.

So to sum up California, under primary development, we've got a very deep inventory of more than 3,700 drilling locations. Nearly all of these are oil locations, and these are located on HBP, or even more importantly, Oxy feel mineral acreage.

The recent Kern County discovery, although very prolific, we don't believe will materially change our gas-oil product mix in California. As I just mentioned, we do view Long Beach as a significant growth opportunity, particularly in light of the recent increases in equity ownership that we've been able to attain there.

At Elk Hills gas plant, the infrastructure is constraining our production. There's no question about that. But I believe we're addressing that now with the 200 million cubic feet a day plant that is scheduled to be built sometime in the next 20 to 24 months. We firmly believe at the end of the year that we will be ordering additional gas plant capacity there.

We're expecting to grow our California production from the 150,000 barrels of oil per day that we're expected to average this year to somewhere between 212,000 and 222,000 barrels of oil equivalent per day in the year 2014. Just like in the Permian, we're assuming no additional exploration success or acquisitions in California to achieve those production numbers.

I'd like to turn now to our Mid-Continent business unit. Last year, I challenged the mid-continent business unit to become more like an independent ENP producer. We wanted them to be more entrepreneurial, more nimble, and I think we're on our way to accomplishing that. In fact, we just recently carved out a portion of our southwestern Permian Basin gas assets and assigned it to the Mid-Continent gas business unit.

I mentioned that the Piceance is one of the biggest pieces of business here for us in the Mid-Continent. We currently have 120,000 net acres captured. More importantly, we've got what we believe is a giant gas resource captured here, some 3.8 Tcf of gas equivalent.

We have 6,000 undrilled locations, dots on the map in the Piceance to drill in our development drilling inventory. But we're taking a prudent approach to our gas development drilling in the short term obviously because of weakness in the current gas prices.

We do have a very excellent acreage position. I think it's primarily characterized by our legacy position where more than half of our legacy acreage is actually Oxy fee minerals that we pay almost no royalty on. That's definitely an economics enhancer.

We've refocused our operations, as I mentioned. Last year, we reduced our operating expense by some 40% through the installation of a field-wide salt water disposal gathering system. We have special fit-for-purpose rigs in inventory, one of which is deployed right now currently drilling in the Piceance. That has really dramatically reduced our drill times from 15 down to less than ten days.

We've also been successful in improving our time to market through sim ops, or simultaneous drilling and completion operations on the limited pads, or the limited pad area that we have in the Piceance.

But definitely this is a growth play. There's no question about it. It's a resource play that we believe it's an area that we can readily add production just simply by throttling up our drilling activity.

I mentioned the low royalty on our legacy acreage. What this slides depicts are our high-graded economics on that acreage that has a very low royalty. You can see that even at a $4 flat NYMEX price, we still generate nearly a 20% rate of return, again the low royalty being the economics enhancer there.

Last, I'd like to talk about the Hugoton just briefly. Again, this is another legacy Oxy field. We've been there since the 1940s. But I think what makes the Hugoton particularly compelling for us these days is an acquisition that we just recently consummated that doubled our acreage position from 700,000 to more than 1.4 million net acres.

What was really interesting about that acquisition is that it brought to us a number of high rate of return oil opportunities. I know this sounds ironic for a gas-focused business unit, but because we have now a large inventory of oil opportunities, high rate of return opportunities, we're going to be focused on that this year, drilling some 35 plus wells in the Hugoton.

So to sum up the Mid-Continent, again, we're taking a prudent approach to gas drilling, a very large resource under capture, north of 3.8 Tcf. The low royalty burden I just mentioned enhances our Piceance economics, and the recent Hugoton acquisition has doubled our acreage position there.

We're expecting to grow our Mid-Continent production from the current 60,000 barrels of oil equivalent per day to somewhere between 80,000 and 100,000 barrels of oil equivalent per day in the year 2014. The reason the range is a little bit wider there in 2014 is that we simply don't know what gas prices are going to do long-term, and that will be a function of what the commodity price does. Just like the other business units, this is from our existing asset base.

So to sum up domestically, we've got a very deep inventory of locations across all of our business units, more than 12,000 locations. We're forecasting a production this year of just north of 390,000 barrels of oil equivalent per day, and we're expecting

to grow that to between 512,000 and 552,000 barrels of oil equivalent per day in the year 2014. This equates to about a 6.5% to 8% compounded annual growth rate.

Lastly, just a few bullet points to sum up our domestic asset base, I think you can fairly say that it's characterized by a stable, low-base decline rate. We've got a very deep inventory of drilling locations, mainly oil across all of our domestic business units. We've got a very large inventory, an exciting inventory, a view of existing new and Co2 flood projects with adequate Co2 supplies already in hand.

California, will most undoubtedly continue to be a major growth driver for us here in the United States where we're expecting to generate a 6% to 8% compounded annual growth rate over the next five years, again, from our existing assets.

The last takeaway I think is key as well, our US business is heavily liquids-weighted. 70% of our production is liquids. We're certainly expecting that this percentage will stay the same as we go forward or possibly even grow in the future. Thank you. That concludes my presentation.

Anita Powers - *Occidental Petroleum Corp. - EVP - Worldwide Exploration*

Good morning. My name is Anita Powers, and I'm here today to talk to you about the conventional exploration program Oxy has in California.

I'd like to start with what I mean by conventional exploration. By conventional exploration, I'm talking about exploration for those reservoirs that are capable of natural flow with no unusual stimulation or techniques to enhance that flow or treatment to get it started.

My presentation will follow the following outline. Like California, where we think it has a high hydrocarbon potential that is underexplored. I'll show you how Oxy came to be the dominant land holder, why we like the geology and how we put plays together. I'll give you some more detail on our Kern County discovery, and I'll follow up by showing you a glimpse of our five-year plan and how we're just getting started.

First, let's restate the agenda a bit, but let's use a map. What you see here on your left are the map of California. The green circles show the major producing Basins; Sacramento Basin, San Joaquin, Ventura and Los Angeles Basins. Those call outs indicate the amount of oil that's been discovered, oil equipment discovered in each of those Basins.

By any measure, California is a world-class hydrocarbon province. Over 35 billion barrels of oil equivalent have been discovered to date, and five of the top 12 US oil fields are in the state of California.

As noted, I'll show you why we believe there's a significant remaining potential, why we believe it's underexplored, and as Dr. Irani has told you and Bill reiterated, Oxy knows what we're doing. We've been in California a long time. We're a leading producer, number one in gas, number two in oil.

We've proven that we're a successful explorer. We have the largest lease holds. Again, we're just getting started.

Okay, I'd like to spend a little time just going back and looking at California's exploration history. There's a lot of oil and gas in California, and exploration started well over 100 years ago. There's so much oil and gas that oil frequently oozes to the surface in the form of seeps. The earliest explorers actually dug these wells by hand.

Around the beginning of the last century, the operators turned to drilling surface features. What I mean by surface features are hills. In fact, Elk Hills is a hill that was discovered by going to the top of the hill and planting a well right on top.

That's generally how oil and gas is discovered. What you see on this chart along the bottom is time. Each one of these blue bars indicate how much was discovered in that year.

The green line gives you accumulative production or reserve addition by year. What you can see here is that by the 1940s, exploration was really starting to drop off. Discovery volumes were getting smaller and smaller, and we started to flatten out in how much oil and gas was being discovered.

So what was going on in that period of time? The majors were the primary producers or explorers of California in the first half of the century.

By about 1940, some key things happened both in California and around the world. In California, the population exploded. There was all kinds of people moving into the Los Angeles Basin. It became more and more difficult to access land, and simultaneously the Middle East was opening up. So the majors were finding it really easier to exploit oil and gas by going overseas.

There's also a perception by the by the '40s, into the '40s, that most of the oil and gas in California had been discovered. All the big features had been drilled, and we were now starting to move into enhanced oil recovery techniques.

So is there really a limited potential? Well, you see here, and I mentioned earlier, over 35 billion barrels of oil has been discovered. But more importantly, 33 billion barrels of oil to date has been produced. That's over a 90% recovery factor if those original recovery volumes were, in fact, true. So I think there probably is a case to be made to see we're underestimated at the time of discovery.

Too little exploration, well, that's probably true. Since the 1970s, very little exploration activities have gone on in the State of California in the form of seismic or in drilling.

Now Oxy's not the only one who thinks there's a tremendous remaining potential in the state of California. In 2008, the USGS, that's the United States Geologic Society, or Survey rather, who are charged with assessing undiscovered resource in the United States on the lower 48 conventional resources indicate California held at least 12% of remaining conventional resource onshore.

This slide shows the last ten years. The blue bars are numbers of exploration wells drilled per year in California. It's been steadily declining really since the '70s, but you can see a slow but gentle decline in drilling in the state over the last ten years.

Probably more importantly is this orange line, which shows as a percentage of all exploration wells being drilled in the United States. There's been a very strong trend down.

So even though exploration is going on in the lower 48 in the United States, it's been leaving California. At peak, it was only 5%. Currently, only 1% of all exploration wells are being drilled in this space.

So I've shown you why I think there's a remaining potential and why I think it's underexplored. Now I'd like to move and focus in on Oxy and how we got to be the dominant lease holder of the state.

On your left again, the map of California with Oxy's lease position in Orange. Oxy's top four competitors you'll see here in aggregate do not hold as much acreage as Oxy. I'd like to give you a little flavor of how we've built this position. I'm going to concentrate in this red square, and I'm going to use it as an example for how we've built knowledge, both technical and operational, and applied it to our thinking of high-lease acquisitions.

So in 1998, when Oxy took over Elk Hills, acquired Elk Hills, we had about 4,000 net acres. Seven years later, we drilled about 20 exploration wells, acquired 800 or so square miles of 3D seismic. We're learning about the reservoirs and the seals in the area. Really, we're liking what we're seeing.

You'll see the purple color there to note our additional lease holdings after that seven-year period. We exited 2005 with about 700 sales in net acres in the state.

Today, we've built our acreage position, as I've told you, to 1.3 million. It's in orange here, these additions. We've drilled about 40 exploration wells. We have almost 2,000 square miles of 3D seismic data in the state, and we've developed new plays and concepts, one of which has culminated in the Kern County discovery.

So now I'd like to show you a little bit about the geology as we were learning, developing ideas and sort of how we went about doing that. Again, the map of California, Oxy's lease position and the major producing Basins shown in the green circles. But I've also superimposed the major faults because California is a tectonically active state. So it's very important to putting together the history and why we like the geology of the state.

Over millions of years, there were repeated cycles of reservoir rocks coming down from the mountains mixing with organic-rich oil and gas source rocks that were coming in from the proto Pacific.

In the areas where these plates and faults come together, or the more tectonically active areas, we were able to stack thousands of feet of alternating reservoirs and source rocks, certainly more in these areas because we could create accommodation space that allowed larger sections of perspective sections. The faulting, the tectonic activity, also helped give us a variety of trap types to trap the hydrocarbons in these reservoirs.

Now I'd like to talk to you about how we take this underlying geology and put it together. On your right, I show you the producing intervals of California. The reservoirs are shown in yellow or blue for sandstone or carbonate. The source rocks are shown in red for gas, green for oil, and the trap types on your left.

Now to show you how to read this chart, I'd like to take your attention to these bars on the side, Los Angeles, Ventura, San Joaquin and Sacramento. Those are to note the major producing Basins. As an example, while the Sacramento Basin is highly perspective, we see about two major reservoirs and one gas prone source rock. Contrast that with the San Joaquin Basin or the Ventura and Los Angeles, you have multiple source rocks, oil and gas as well as multiple reservoirs.

Now all of these trap types, as I indicated, are actually seen in each of the Basins. In a play analysis, you pair reservoir with a source rock with a trap type. We call that a play.

Now one of the most attractive things about California geology and that we frequently see as we go forward in our prospecting, particularly in the areas we have six accommodation space, multiple reservoirs and source rocks, you can stack these plays. Now the beauty there is one wellbore can encounter more than one play type. That gives you a bailout zone if you're not fortunate enough to have all of your play types working. So that's something that we'll talk about in a bit. I'm going to show you an example.

So after doing this analysis of source rock, reservoir type and trap, Oxy geoscientists came up with 47 play types, the bulk of which were in the San Joaquin. That's still a lot of plays to look at, and not all plays are created equal.

So we put some filters on. I'd like to talk to you about that filtering process. First, we want to concentrate on oil prone plays. I secondly want to very strongly reiterate you can't do this sitting in your office at a work station. You have to look at all of your data.

Much of the data in California is actually pretty old. It's in the form of hand-drawn logs with notes. Our geoscientists took that, looked at seismic and then said, "I've got to go out in the field. I've got to test these ideas," because just because a geologist 50 years ago said, "This reservoir stops here. This source rock is gas prone," we didn't choose to believe that.

So we went out in the field. We measured. We took samples, and we came up with our own ideas.

Even beyond that, we need to say, "Okay, how are we going to concentrate our resources on these ten play?" Now I'll introduce the concept, the names of some of the plays that we'll be talking about.

We'll certainly, in the ideal state, we'll have a large volume and a lot of running room. That's what we see with our discovery play you know as the Kern County discovery. But I call it the discovery play deliberately because we believe that it extends outside of Kern County. It has the highest volume exposure, and we see a lot of them. We have several lease maps in this particular play type.

Now contrast that with what I call the bread and butter. Well, the bread and butter are what the operators in California have been reliably drilling the last 50 years. They're relatively in prospect size, but there's a lot of them. We don't build a program around them at Oxy. But when we find them, we put them in our drill schedule, and we put a drill bit to them.

Now in the middle, you see high potential. As I mentioned, California, amazingly for the potential that it has, is underexplored, and there's very little 3D or modern oil field techniques have been applied. With our 2,000 square miles of 3D, we see plays that have been overlooked, and we also see some new ideas. Those are in that high potential category.

Finally, emerging. We've come up with some play ideas, may or may not work. They're not proven. We'll put one or two of those into our portfolio every year. I'll show you more specifics on how we break out our plays in a moment.

So as an example of how our plays fit on a prospect exposure, this graph, the green lines, show all of the field sizes that have been found to date in California and how each of our plays fits on a distribution. For instance, our discovery play has potential to be 500 million barrels of equivalent.

So now I'd like to give a little more detail around our Kern County discovery. In 2008, we had a concept which we had developed as we had been building our concepts for the state, and we drilled a concept. It was successful. We had a discovery. In 2009, we moved to an entirely different area in the state. We drilled our second discovery, the Kern County major discovery that you're all familiar with.

There's two important things here other than the fact it was the biggest discovery in many, many years in California, and one of which is it showed that our play concept was not a one-off. This is repeatable. We were very happy about this.

Secondly, and I'll talk about this in more detail in a moment, we've drilled two plays. Remember, I told you the concept of two plays? We had both a conventional play, which I'll give out more detail on, as well as an unconventional play in a shale section.

So moving just to the left of your screen, I'll talk a little bit about the conventional play, a clastic zone with 1,000 feet of hydrocarbon divided into two sections, the upper reservoirs, gas condensate. You'll see that the IPs of 10 million to 30 million of cubic feet a day, very high quality condensate yield.

We also have a black oil zone, a lower oil reservoir zone, with IPs of 100 to about 2,000 barrels of oil per day, quite a bit more variable. I'm going to talk about this more in a moment, but this variability is because of the reservoir quality. The shale zone, which is actually five shale members in over 1,000 feet, each zone capable of an IP of 100 to 500 barrels of oil per day.

Now on your left, I've drawn a depiction of the conventional reservoirs. They're 1,000 feet of interbedded silts and sands. The upper gas condensate, which has a more consistent reservoir performance, is a sandier section from the lower oil zone, which has a bit more silt.

To date, we've drilled 24 wells at our discovery, and we've defined one edge. On that edge, we see the beds start to deeply dip. What we've noticed is that where we get into that deeply dipping edge of the field, we have lower flow rates.

Now we've been successful in the last quarter. We've done it for six wells now. We've modified our completion and seen what would have previously been a relatively low flow to over 1,000 barrels of oil equivalent, very encouraging.

Also, to take advantage of these six sections of highly interbedded sands and silts, we planned two horizontal wells later this year. Of the 20 sells Bill told you we were going to drill to exploit the oil reservoir, two of these will be horizontal. If that's successful, we may add to that.

We don't know how big this field is yet. We have not defined the other three sides. We have not determined the aerial extent, so horizontal we don't know.

We also don't know vertically. We have not defined definitive context for oil and gas, gas water. So we still have some delineation and really step-out drilling to go.

So after 24 wells, where are we? Proved and produced 88 million barrels, over 60% of that proved developed, probable, add another 47 million barrels. Our possibles have a wide ranging 40 million to 115 million. The 40 million is a conservative one-well spacing.

I believe that what I've just shown you with the enhanced completion we're going to really see that we can move this number to a higher side of the 115 million. So I feel pretty good that our range of 175 million to 250 million is really going to land closer to the 250 million side.

We have not defined the field limits. We plan to continue exploration drilling along the feature, our step-out plan, which could add 100 million, an additional 100 million to 150 million barrels for a net to Oxy 275 million to 400 million. On a gross basis, it is not a stretch to say that the Kern County discovery is half a billion barrel find.

Now on the production side, as Bill told you, we're facilities-constrained. We're currently at 30,000 BoE per day. We expect excess a year after installing out skid-mounted gas facility at 45,000.

Okay, now I'd like to show you where we're going. Last year, we drilled 25 wells, shot 200 square miles of 3D. This year, we expect to do the same, although we'll more than double our seismic. We expect to keep this pace, if not ramping up a little bit, over the next five years.

Where do we plan to do it? Well, we plan to concentrate most of our effort in the San Joaquin Basin, and we plan to concentrate in the discovery and high-potential plays, which have the greatest exposure to reserves. We'll continue our seismic program as shown.

So I think I've shown you we have a tremendous potential. We have a very attractive risk profile, largely because we can stack these plays. Over the last couple of years, we've got a one in three success rate.

We are the dominant land holder. So we've got the land secured to put our ideas in motion. We've proven that we have play concepts that are significant, and our Kern County discovery certainly shows that, 175 million to 250 million barrels of oil equivalent, and I think a pretty comfortable upside.

It's not a one-off. We have plays. This play, we see it extending beyond the Kern County area. We intend to drill seven to ten prospects like this every year, each prospect averaging 100 million to 125 million barrels equivalent, each with an upside of 500 million barrels.

We'll target areas more oil prone than our Kern County discovery. We do have a multiyear inventory already mapped. It continues to grow.

We learn every time we drill a well. We change our thinking a little bit. We prioritize again, and then we drill it. So with that, I think, we have a break.

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

We're going to take a brief break for about 15 minutes. I'd like to have you all back here by 10.35 if you may. Thank you very much.

(BREAK)

PRESENTATION

Todd Stevens - *Occidental Petroleum Corp. - VP - California Operations*

Good morning. My names is Todd Stevens. I'm responsible for all of Occidental's operations in the state of California. But today, all I'm going to talk about is the unconventional opportunities that exist and our assets that we're very excited about at Oxy.

This is a converse to what Anita showed you earlier. This is lifted exactly from the Schlumberger presentation. Basically, it's showing you what we're talking about here, producing from unconventional reservoirs, reservoirs that you need something to get economic flow rates. You need some kind of stimulation, some kind of technology to work for you.

Here's how I'm going to walk you through it today. First, I'm going to give you some background in California shales. I'm sure you're not that familiar with them. Most people aren't; talk a little bit about California Oxy shale program in California; tell you about some attributes of the shales in California from a technical standpoint; I'll point to some shale analogs that you're more familiar with in North America; and ultimately roll this all together and summarize it for you.

You've seen this map a few times with Anita. In orange is our existing acreage in California. But what I've outlined in blue here, as you'll see on the map, is where there's existing shale production in the state of California. It's in the Los Angeles Basin, the Ventura Basin, the San Joaquin Basin and actually offshore California, the shale productions.

I put shale in quotation marks for a reason. It's become a convention to use the term in the industry. But if you look at what real shales are and kind of the pure shales, we're talking about Devonian shales in the eastern United States with the Woodford and Bakken shale.

The kind of shales we're talking about here, and mostly when we use this term shale, are really interbedded silt stone, in a lot of cases where the shales are actually less than 50% shale. They might be quartz or something else.

I'm going to orient you a little bit and talk about the four major producing Basins in California, just a little bit more detail than you saw from Anita. This is a stratigraphic column of California. You might be more familiar with the San Joaquin Basin, the major multibillion-barrel fields in the San Joaquin produced from the Tulare and Etchegoin.

In yellow on this chart, you'll see the sandstone conventional reservoirs that you're used to hearing about in California in the four major Basins. In purple, you'll see the source rock or shales that we're going to talk about and the unconventional opportunities that are associated with them.

Now if we target the shales and look at what are we actually looking at here, it pops up with five shale zones. We quickly dismiss the Sacramento shale down on the bottom. We'll talk about that later, why technically today it doesn't work from existing technology.

What we've done is talk about the four shale zones, the Antelope, the Lower Monterey, the Santos and the Kreyenhagen. You'll see here due to the rock spaces in California as being deposited in a tectonically active area, that parts of the San Joaquin Basin and the Ventura Basin actually have the Santos be split, and in parts of the Basin it's together.

So that's why in some areas where the Vedder and the Phacoides come into play in the San Joaquin, you'll have two separate parts called the Santos and the Santos Salt Creek. These are what we're going to refer to as just the Santos when we talk about it today.

Now this California shale play has really been under the radar. But at Oxy, in particular, we have been on top of this for some time and a number of years. We'll see later today, as I'll show you, it compares very favorably to other plays you're used to hearing about in North America.

Really, since we acquired Elk Hills in 1998, it came with some built-in shale production, and we've been building our expertise slowly from Elk Hills and moving it onto other assets we own in California. We really had no basis to try and promote this like some of our peers and independents might do because we were looking to acquire more assets and get more mass in California and we wanted to do so at reasonable prices.

Now if you start looking at California in total, but zoom in on the San Joaquin Basin, which is the most prolific Basin in California, there's been a historical perception about California. Anita talked about it.

People gave up on California long ago. They thought about it being permeable sand. They did field glass geology and drove surface anticlines, surface features that made it real easy. They found huge fields and then they focused on exploiting those huge fields.

They thought the shales in California were good source rock, but nothing more than source rock. They didn't think there was any carbonates in the state except for sporadic dolomites.

The bottom point here is they really thought there's nothing material left for anyone of size to chase. They thought, "Let's leave that to the small independents and the mom and pops in California to go find the 0.5 million or 1 million barrels discovery that still exist out there."

But what we've shown at Oxy is, in fact, there are tight sands in California with shows and potential with proper stimulation techniques. We've had a lot of success in the shales, and we're going to walk you through it here today.

There are carbonates in the Lower Monterey and the Santos. Actually, the carbonates are very similar from the mineralogical standpoint to the Hanesville. The calcite content is very similar, and the Youngs modulate is actually very similar to the Hanesville. We've had encouraging results as we continue to move our program away from Elk Hills where we started acquiring our knowledge initially.

The ultimate proof in the pudding was the Kern County discovery. California is underexplored, and there's a lot of resource left to prove.

Now if you step back and just say, "Let's look at the San Joaquin Basin and talk about the four shale zones we're talking about," this gives you an idea of the sheer magnitude of the petroleum resource generation capability in the San Joaquin Valley in the four major shale zones we're chasing. This is hundreds of billions of barrels of oil.

To give you an idea of just to broaden that scope to the state of California, in the state of California, there's been 9 billion plus barrels of oil fields discovered. There's been nine 500 million- to 1 billion-barrel oil fields discovered in the state to date.

So you've already had 18 oil fields of over 500 million barrels discovered in the state. This is a huge petroleum province, and the San Joaquin Basin is the most prolific of all of the four major Basins.

Now you can't have oil without a good thermal regime and a good source rocking kitchen. So what we've done here is you lay on where the maturity exists in the thermal regime for hydrocarbon.

We laid it on top of our acreage in yellow. In green you'll see here is existing oil fields. Red is existing gas fields. We have it in the Ventura, Los Angeles and the San Joaquin Basin.

Again, this is not all one zone. We're not talking about the Antelope shale. We're not talking about the Kreyenhagen. We're talking about the potential in any one of those zones. Particularly in the San Joaquin Basin, we have multiple pay zone potential with regards to the shale in an unconventional play.

Now I'll zoom in here so you can get an idea if you look at it just in the San Joaquin Basin. Again, oil fields in green, gas fields in red. The overlay, which Steve likes to call the whale here, and then Oxy leases or fees in minerals in yellow. Again, this is all zone. In some areas, as I'll show you in a second, some of the zones for the different shales are more perspective than others.

If we zoom in on the Los Angeles and the Ventura Basin, you can see how our acreage overlays the thermal regime in those areas and why we think we're in a great position in both Los Angeles and the Ventura area.

Now let's zoom in and talk about one particular shale zone in the most prolific area in the San Joaquin Basin. This slide shows the biogenic silica phases in the Antelope shale and the San Joaquin Basins.

What happens, and it's a very particular characteristic in California shales, is that silica originates in diatom casts. Over time, with deposition, it changes phase from highly porous and morphs in Opal A, Opal CT, then to quartz. But the thing that's unique here is all three of them actually produce in the state, and all of them require different production and stimulation techniques to ultimately get them to produce.

To give you an idea, if we put through and look at where is Opal CT where we think the thermal regime is mature enough before production is in this area on the left side of the San Joaquin Basin. We click on the Opal CT, and we see as much broader area. Again, a lot of our peers in our cells are already producing some of it.

Then, in the quartz phase, again, this is just the Antelope shale. Obviously, it's not a blanket everywhere. It requires different production stimulation techniques, a lot of work to understand and be able to produce from these different parts of the Antelope shale.

Now I'd like to spend some time and talk about Oxy's shale program. What have we done in the state? Really, the shale drilling started for Oxy when we acquired Elk Hills in 1998. We actually acquired existing shale production at Elk Hills.

Once we acquired the production, we started looking at it and figuring out how can we optimize this, how can we make it better? We actually had an analog when we bought Elk Hills. Bill referenced the North Shafter field.

At the time, it was recently discovered by Texaco, and we were analogs as some of those wells there were a basis for part of our acquisition at Elk Hills and some of the shale work we could do.

But after time, we spent a lot of time doing this. As we moved away from Elk Hills and drilled more, we've now got our production in California. Over a quarter of it is from shales. We've expanded that concept beyond Elk Hills. We're now in eight other fields where we continue to test the concept across different Basins. I'll show you a map of that in a second so you can get an idea of where we're talking about.

But what we're talking about today is actually undertaking a four-year development program that plays over 20 billion barrels of potential oil in place from our shale acreage in the most likely areas.

We think that we're going to acquire 10 to 15 test wells per year in different areas, and we're going to drive on the fly. If things get better in one area or worse, we'll obviously ramp up or slow down our opportunities or appraisals for that area.

As a part of this, we're going to be shooting the largest 3D seismic program in the history of the state this year. This is going to help us identify sweet spots, natural fractures, good reservoir characterization.

This just represents where we stepped out and gone into the eight fields. As you see, we stepped into the LA Basin. We stepped into the Ventura Basin, and we stepped away from Elk Hills in the San Joaquin Basin.

We have a lot of running room. We have over 1.3 million acres in this state. I know you've heard that a few times already. But we also have quite a few opportunities to continue to move us forward.

This graphically represents what happened at Elk Hills and what's happened since then at the other eight fields. We bought Elk Hills. We had some built-in shale production. As we've worked on it and we've cracked the code, we realized large-scale acid treatments for what was needed at Elk Hills.

Once we did that, you can see what happened with production here. It ramped up rather dramatically. Then, we started moving it. As we got over here into the 2005 timeframe, we started stepping away from Elk Hills and continuing to try this concept elsewhere and continue to prove the concept up for ourselves.

So let's just talk about four of the fields. Elk Hills, obviously, is the bulk of the work. It's where we started, where we built our knowledge and expertise.

You'll see here we've drilled a lot of horizontal and vertical wells. These costs are fairly preliminary. We think they're going to come down. Also, the IPs are going to go up. We think over time performance is going to be enhanced, more technology is going to be brought to bear and we're rather excited about it.

The one thing I'd like to focus on here, and I'll highlight in yellow for a second, is the first-year decline. I know a lot of you look at shale plays around the country, and I know you don't see first-year declines like this. It's really because of the unique nature of California, the source rocks and the shales in California.

There's considerable discussion right now about how do you do reserves for resource plays. A lot of people are using hyperbolic declines with fee factors greater than one. We, in fact, think it's much more appropriate to use two exponential straight-line declines, a first year and then a flattening out after the first year. We don't think there's any physical basis to actually use hyperbolic declines in the shales.

What's the key to the success in the shales in California? The stimulation recipe. We see it. Large-scale acid treatments worked at Elk Hills. Modifications of that have worked elsewhere. Sometimes, it's the exact same recipe that worked elsewhere. But it's different everywhere. There's no one size fits all.

It's critical to understand what the production testing in intervals. You have to understand what's wet, what's not and what the hydrocarbon properties are. You can be talking about lower-quality oil, API 20, or you could have 40 or 50 API oil. So it varies greatly, and we'd like to produce that and have the right facilities for that.

Reservoir characterization is critical. That's why we're shooting so much 3D in the state. We piggyback off of what Anita is doing from the conventional standpoint and use it for our unconventional plays. In particular, the natural fracture of modeling is important for us.

Ultimately, reservoir management is critical. Understanding how we complete individual zones or can we complete multiple zones at once, and optimizing the length and the number of fractures give us the best economics, which ultimately is the most important.

I'd like to show you a few type curves just to give you an idea of what we've seen in California to date. In the patches here, this is an Elk Hills area shale vertical well. I say area because it's a general area around Elk Hills.

This kind of shale well is only producing from one of the four shales we're talking about. But each one of these four shales, when you actually get into them, you understand they're subzones. In some cases, there's five. In some cases, there's four.

This is an example of opening all five sub-shale well in all five subzones. This is on a BoE per day basis, a horizontal well and a vertical well.

Break that down for you on a vertical well and understand what's the oil and gas mix that we're seeing in the state. You can see it's pretty close to 50%-50%, 60%-40%, plus or minus on oil and gas. Then, you look at the same basis for a horizontal well, very similar looking, just more rate.

Now I'd like to talk a little bit about technical attributes of the California shales. As you look at this chart, you'll be able to see real quick at the bottom why we took Sacramento off the list of things to focus on at this point in time.

But we should be able to continue to study it simply because the Sacramento Basin has had very few penetrations, particularly in the middle of the Basin to the actual Sacramento shale. So it's a little preliminary to condemn it, but it's also -- it doesn't look as perspective as some of the other ones to focus our efforts on at this point in time.

As you can see, the one thing that jumps out at you immediately if you're used to looking at the shale plate in North America, is the thickness. Why is it so thick in California? Well, Anita talked about the tectonics.

We're in a very tectonically active area. The compression of loading creates tremendous stress in the area and has created tremendous thicknesses in the shales and in the pay zones and ultimately sandstones in the state also.

As you also look through and you see all the other reservoir attributes, you can see this is a very attractive area that compares very favorably, if not better, than some of the other shale plates you're used to seeing around the country.

Let's talk about some of the critical technical aspects of the California shales. They're very organic-rich. They have very good total organic content.

The one thing that's most misunderstood about California shales is thermal maturity. California is fairly unique. To give you an idea looking at bitronite reflectance in California is 0.5. Most people know, geologists in the room, will know that you need 0.6 to 0.65 to have maturation and migration to hydrocarbons everywhere in the world.

But California has a transformation ratio, and transformation ratio is a function of source rock chemistry and temperature history. California shales expel more hydrocarbons faster because of their unique nature relative to other marine source rock. This is because of the tectonic environment, the high temperatures and the high stresses that are in place here. This ends up leading eventually having great source rock and great reservoir rock.

We've already talked about the gross thicknesses. This is an active margin Basin compression loading. That's why you end up with these enormous thicknesses, these gross thicknesses that are unbelievable compared to some of the other areas you see.

California is a unique depositional environment. Most of the shale plays you see around the country were deposited in restricted shale water environment akin to a swamp. In California, it was deposited in over 3,000 feet of water. You'll see that this actually makes it unique in most cases in most North American shales.

It's also diatom and foram rich. The diatoms are a particular attribute of Monterey, which is a characteristic of a Northern Pacific rim, and it's unique to this part of the world.

I'd like to talk a little bit about California's shale analogs as we see them as we spend quite a bit of time at Oxy looking at what's happened around North America and the frenzy that's gone on in both gas and oil shales opportunities.

As you've seen, California oil shales compare very favorably to what you've seen elsewhere in the country. We actually think the best analogs are the Bakken and Eagle Ford. This is because they both have a lot of hydrocarbons in place, and there were a lot of hydrocarbons ultimately generated before that.

The reservoir parameters, as I'll show you in a second, are very similar, and the predominantly oil and liquid plays for Bakken is very oil-focused. The Eagle Ford is becoming oil-liquid-focused as everyone wants to drill in the oil window now.

The one thing we've seen, and as we've looked at all these plays, is there's significant learning curves and a significant payoff. As we've learned in California, and as we've seen people learn in the Bakken and Eagle Ford, the more time you spend on these, the more technology you bring to bear, the better they are understood and the more perspective they ultimately become, which is excellent for Occidental.

Now I'd like to walk you through a side-by-side comparison of the California shale for the Bakken and the Eagle Ford. First thing that jumps out to you, obviously, depth. Because there we're talking about multiple pay zones in California, the depth is greatly different. I mean, you're talking about 3,500 feet to 16,000 feet, four potential pay zones in the San Joaquin Basins, akin to the Bakken, the Bakken having the middle Bakken, then in most cases the Three Forks Spanish underlying it, and then the Eagle Ford.

Thickness, again, I don't think there's anything that compares when you talk about thickness, gross thickness, of what the opportunity is. California, because of the active margin Basin, the compression loading, the tectonics, it's unparalleled in the opportunities from that standpoint.

Porosity, I think you can draw the same conclusion. The porosities in California are much more attractive than the two probable analogs.

The permeability is comparable and, in some cases, better than what you see elsewhere. This is obviously an important factor in stimulation and why you do that here in the state.

Total organic content, there are parts of the Bakken which we know have better TOC than California. But on average, we think California has one of the most attractive total organic content of any of the shale plays you might look at.

Now I'd like to roll this all together, what does this really mean for Oxy, and summarize it. Well, at Occidental, as we've hydrated our acreage, we think we have about 870,000 acres that are within the most perspective shale plays.

Because of our huge amount of fee mineral acreage in the state, as Bill talked about, we have over 1 million net fee minerals in the state. We have a large NRI. We have approximately 95% on this acreage.

The most attractive part about it, as Anita talked about bailout zones for exploration, we have mostly potentially productive shale zones in each well. To give you an example, the Kern County discovery, we might be up here talking about the shale zone

of the Kern County discovery instead of the Kern County conventional part because that was how attractive it's turning out to be.

But because of the attractive economics of the conventional portion, we've been spending our drilling rigs and drilling money going after the conventional portion to date and not done as much on the shale zone. But in its own right, it's a great part of the deal for us.

As I've shown you also, our acreage throughout the state encompasses the most favorable thermal regime. We're actively looking to pursue that some more.

We've identified 15 areas of plays over the next four years, just about 5% to 10% of our total acreage of the 1.3 million net acres. We've initially targeted one to two areas, including the Kern County discovery.

We see average IPs of 400 to 800 BoE a day. But this actually ranges so far from about 100 to over 1,000 BoE a day. It also depends on how many zones you open up because we talked about subzones and different zones in the shales.

Average EUR we're seeing per well is between 400,000 and 700,000 barrels. We ultimately think we're going to develop this on ten-acre spacing, but we think in some areas we might go down to five-acre spacing. The most exciting thing about it for Oxy as I sit here today is we think in the next ten years, this could actually become the biggest business unit at Occidental.

Thank you for your time. I'd like to now turn it over to Steve Chazen.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Thank you. It's always hard to follow that sort of thing. So I'll try to roll ahead.

I'd like to talk briefly about our Midstream and Chemicals business, the only time I think I get a chance to talk about it. So it's every four years. Then, I'd like to roll the production forecast up, talk about how much money it's going to take to do this; talk a little bit about acquisitions' talk about our asset returns; a traditional question, "What are we going to do with all the money?"; and then talk about the investment attributes of the Company.

A Midstream business is average $375 million a year, last year, $235 million. We've got a lot of net investments. It's a significant and growing fee income. Most of the money comes from gas processing, as we'll see, and some from marketing and from some of the pipelines.

Gas processing is near our domestic producing operations, processes both our gas and third-party gas, basically a spread business between natural gas prices and NGL prices. A lot of the profits that we show that we would otherwise show in the segment are passed back to the oil company and it shows up as higher prices. So when we process our own gas, it doesn't show up in this segment, it shows up in the oil company or the oil segment. I'm not allowed to make a profit twice, apparently, under accounting rules.

The marketing and trading business is primarily maximize the value of our company's production. What makes it more profitable or less profitable in some years is the spreads between various grades of crude. We blend a lot of crude as a company and again almost all the profits are passed back.

We have a fairly sizable gas storage business. We buy gas in the summer and sell it in the winter, hopefully we make money. And Phibro is among a basket of commodities. Our pipelines, large business in the Permian Basin, we own 22% of planes all American GP. Sandy's already talked to you about the Dolphin business, basically a fee based business. There's a lot of blending that goes on in this business and we actually make a lot of money -- again some of it passed back.

The power of business, except for the Elk Hills power business, almost all the profits are passed back to the chemical company. It's a spread between natural gas prices and electricity which drives the business.

On earnings basis we expect the business to grow to about $1 billion dollars by 2014. Increased pipeline fees, addition of Phibro, Co2 Plants will sell some third-party gas there, and some increased gas processing. In addition, we historically added additional pipelines. We bought Exxons pipeline, BPs and the Planes All American. This business will grow to $1 billion annually we think by 2014.

Another business we don't talk much about is our chemical business. The last five years it averaged $688 million in earnings before interest and taxes. It's about a 10% -- 17% return on property plant equipment. Last year it was a lower year, about 10%. It's basically a vinyl's business, produces chlorine and caustic soda. 80% of its cost are natural gas, it's a major factor in the industry's first or second and the earnings are unpredictable or volatile, however you want to describe it. It generates a lot of free cash and has never lost money.

PVC is the big end product, building products and automotive products. The caustic soda goes in the pulp and paper and water treatment. We have a business for fertilizers. I think one of the more interesting things that's gone on, that our percent that we export has grown from 29% of our output to 41% in the last few years. Most of it the Far East and South America. It's really driven by the low natural gas prices in the United States. You can really compete worldwide a lot better today than we could a few years ago.

And we make other products that account for 12% of sales and 16% of earnings; these are more profitable businesses actually than the chlorine-caustic business, just smaller. And in a downturn, they act as a bigger percentage of our profits. It's not a bad business when you compare it to other people, we take about 20% or so of our sales and into EBITDA and compared it to other people we think it's a pretty decent business. Literally not real exciting.

We expect our average earnings to be similar this next five years over the last five years. I'll remind you, a few years ago it made $900 million. What could go wrong, in a manner of speaking, high gas prices could probably make it go wrong although it wouldn't be all bad?

I'd like to talk now about the E&P business which of course is the core of the Company. When we started, we talked about the 5% to 8% growth. What's baked into that is the Co2 and the preemptive Bill talked about. The current California prospects, that is what we see -- what we actually have captured and what have we drilled in the next little bit; Rocky Mountain Gas at about $6 and then the Bahrain, Oman and Iraq production that we talked about earlier.

This is just in California, just what - pretty straightforward development drilling, if you will, in California. The orange that you'll see in a minute is the upside form existing holdings. These are the extensions, if you will, of the California conventional-unconventional prospects. They've already sort of been discovered and we see those as pretty low risk.

Permian exploration, which we see as very likely, $7 gas price for the Rockies and more labor peace in Argentina. Obviously there's additional opportunities from our balance sheet and cash generation for domestic property acquisitions and potentially Middle East projects.

We look at the California non-conventional, that Anita talked about, one of the drivers here is the fact that we don't have any royalty's. Todd talked about that we don't have any royalty's. This really proves the economics, normally pretty strongly. We've only built a modest amount of success into our wedge. And our conventional, which is in yellow, we have 50 prospect inventory and growing. We've only built in two or three moderate exploration successes into the wedge.

Total California growth over the five year period is 17% compounded over 300,000 a day. That includes the counting for the decline and all the other things. And the Rockies, 3.8 Bcf of potential, the base uses $6, the upside case is $7.00. We're not showing any higher than that but obviously if it was $8.00 we'd drill a lot more wells. The Permian Co2, the net barrels form our

operator properties only, possibly more Co2 will be available over the period. I think it's pretty likely that we'll get better response in the 2013 through 2014 period, which we haven't shown.

We'll do the best stuff first; I think we'll get better responses than Bill's shown in the Permian. I will say, we've tried to be fairly conservative about the California outcome. We think and we'll be disappointed really if we don't do a lot better than this but the numbers start to get pretty ridiculous out there in 2014 if we started to build in what we actually thought.

We're expecting the domestic business will grow somewhere on the low side of 6% and the high side about 11% a year. We think is a reasonable probability that we'll grow from that. The blue in the bottom is basically in house; the other pieces are the yellow and the blue - or whatever color it is on the top. I think are pretty likely and pretty conservative.

Middle East, I still think there's more opportunity in Bahrain. We show steady but not aggressive progressive. There's a lot of work that Sandy has to do there. We think it's probable that we'll get better oil results by 2014. In Oman the development of the gas market is still fairly early. We think by 2014 there'll be more gas and probably better growth. In Libya we've really not assumed much and the possible need for the government for better production growth by the end of the period gives us at least some hope.

Argentina, there's a lot of potential in Argentina; some of it's in the yellow zone. We're hoping for labor peace. If we get that we'll do very well in Argentina and we'll way exceed our numbers. Finally, in Iraq the one field we have has a lot of other zones that could be developed. Some of which we have contracting rights to, others we don't. We feel we're clearly capable of outperforming our estimates. We haven't built any of that in but I think that's at least some possibility of that.

We've accounted for the Dolphin production sharing contract and the loss of the ENI contract. International production growing at 7.5% a year, a fairly sizable increase over the period.

Looking at our total business, we're looking at growth of over 9% a year at the top, compounding everything, the variance exploration, exploitation. We think there's a fair amount of upside from that. We tried to be conservative, especially in timing, to make sure that we actually deliver what we promised.

All this is going to cost some more money than where our normal rate had been. This year we spent - we're going to spend about $4.5 billion, you can see the breakdown there. California will go up about 50% in dollar terms per year, for about $900 million to about $1.3 billion. Permian is over $700 million on average and the Mid-Continent gas to about $600 million. Middle East, North Africa will spend a little more money but its percentage will be about the same. The chemicals and Midstream, as the gas planners are done; chemicals and Midstream will spend less.

Our business for the last decade, at least, has been acquiring assets that can provide future growth to improve recovery. The goal of any acquisition is to make the Company better not worse. We've done this through foreign contracts, domestic add-ons; we tend to have small incremental additions for production. The short term are basically designed ahead to our production three, four, five years later. We expect to generate at least 15% after tax, United States, and 20% internationally. We're using moderate oil prices.

We talk about our finding and development costs as less than 25% of our selling price. Rather than use the true -- we use six to one so make you feel comfortable. But we also look at how much of what -- converted based on the selling price of the product, so that gives a much less attractive conversion price for natural gas.

Obviously, even with the additional capital shown, the program will generate significant amount of free cash flow. We continue to see a large number of opportunities over the next five years. There's no reason for us to believe that there'll be less opportunities over the next five years than there has been over the last five years.

The Permian, Bill pointed out, 1,500 operators on the low side, 75,000 royalty owners. We acquire a lot of that every year, there's more that comes every year. We expect that to continue. We still see some acquisition opportunities in California, there are a few large acreage holders and we're hopeful that that'll come to pass although we don't really need more.

The United States, we continue to make small investments in the emerging plays. First to gain knowledge and we hope to find another area that will work for us. And additional foreign contracts are all fairly likely.

Our business, I said earlier, is a business really of improved recovery. We acquire one way or another, properties with lots of oil in place and convert them to improve recovery into reserves. The production thought will follow the reserves. What you'll see is a pattern, in the early years of acquisitions, the booking associated with the acquisitions and the improved recovery additions two or three years later, then the production will follow that. So I think it's a fairly cyclical pattern.

Looking at the acquisitions in dollar terms rather than in some barrel terms, you can see for example in 2006 there was a lot of acquisition activity. You can see there was improved recovery coming in 2007 and 2008, and we expect the 2008 investments to show up in 2010, 2011, and 2012. So it's delayed several years so we're pretty confident about our additions over the next few years.

Ray said earlier, and we said four years ago that our targets were 15% after tax -- for the United States and 20% after tax for our foreign operations. We took this directly out of our Annual Report 10-K, basically we took the net income we show and divided by the assets. Our five year average United States was 19% after tax. Internationally, 24% and overall for the total E&P business, 21% after taxes.

Looking at the cash flow, that is the money that comes out of it that has to be reinvested, on average it's just over 30%. That is to say we have to reinvest - we get to reinvest 30% of the property plant equipment every year. Which means, over a four or five or ten-year period, certainly, we have to really put back all the money and then some into the business. This is a fairly sizable challenge. This is a fairly sizable business. So it gives us an opportunity to reinvest but the results you see over five and ten years are the results of the programs over this period, not the results of some historical outcome.

I'd like to give you a little insight into how we think about F&D, how we manage the returns. We like to have our F&D to be under 25% of the selling price of the product. So here's the traditional six to one conversion and then we converted it based on actually prices over the one year, three years, five years and ten year period.

And we've done better over the ten years because we weren't clever enough to figure what was going to happen to oil prices. But we've pretty consistently run about a quarter. That gives about a quarter for F&D, about a quarter for overhead and dry holes and other failures, and about 50% for the profits. This ties extremely well to Bill's numbers on our Co2 business.

So if you want to know how we think about it, it's not this six-to-one stuff but really as a percentage of what we expect to sell the product for. Gas is not the same as oil, rarely has been. We don't expect it to be in the future. This six-to-one is misleading on a good day.

We've talked -- we've shown this slide more times than I care to remember, about what the cash flow priorities of the business are. Our base maintenance capitals are our first priority; our dividends are next, our growth capital and finally acquisitions.

We try to estimate over the next few years what our base and growth capital would be. We've grown the base capital -- as the production has grown, we've grown our base capital. So we estimate over the multi-year period it'll be about $15 billion total, about $3 billion a year. Towards the end of course it'll be more because we need to maintain the existing production that's existing that. We spend about $11 billion on growth capital over the period. This splits about the same, about 42% of the capital to grow the business and 58% for the base. The remaining capital to add the $27.5 billion is chemicals and other.

Shareholder dividends are an important part of our business. Somewhere between 60% and 70% of our shareholder base are basically dividend growth buyers. And those have been some of our longer shareholders; our dividends have grown from about $600 million in '05 to $1.25 billion. It allows the investors to diversify if they want, and in turn, is good discipline for the management. I hope you'll forgive this soapbox here.

We've listed companies A through J, we've listed in the back, the list of peers. They're not in the same order as A through J but this shows our proved develop reserves as a percentage of our total reserves. Negative surprises we think are bad for shareholders.

One of those negative surprises would be on develop reserves are very difficult to estimate and the costs especially are difficult. So we keep a high percentage of developer and undeveloped, probably conservative but we think this serves us well. It keeps our DD&A rate reasonable and related to our actual spending.

This is the percentage of that. We're not amortizing as a percentage of our PP&E and we show you some other people. You understand that all of these unproved properties that are held, not straight-line amortized, and the goodwill, will eventually go through the income statement. There's no other place to put them.

And these are the so-called noncash charges. Now, of course they once were cash but now they're not, I guess. These are some of the negative surprises we try to avoid having. So we amortize a lot of our PP&E, we put as much as we can into the proved producing class for cost purposes. So our DD&A rate amortizes the property, plant and equipment account. Some of these are very well known companies with 40% of their PP&E not being currently amortized. I don't know what the earnings of such a company would be.

Continuing with the soapbox; we view our job, as managers, Ray and I and the rest of the team, converting the money we get to keep, the shareholders equity that we kept, converting into stock market value. You can't do that every week or every month or every day but over five or ten year period as you recycle all this cash that we talked about earlier.

It's fairly straight forward and easy to measure this. You look at your beginning and ending shareholders equity account for the few companies that have written off more than 5% of their property, plant and equipment in any one year. We've added that back. And then we looked at the stock market value they've created. So for every dollar you retain, how much did you give back to the shareholders at stock market value?

So really we talk about a lot of things. We talk about health, environmental and safety; this is an important part of our business. We talk about financial - low financial risk. We also talk about conservative accounting. We do those things to eliminate the negative surprises. Negative surprises will kill this sort of calculation.

The F&D is important, our reserve replacement is important but it's just a matter of at what cost. A return on invested capital is important but it's easy to make good return on invested capital if you deplete your business. Dividends are also important but if you're not growing your business and we think growth is very important for oil companies. If you're not growing your business, the dividends are liquidating dividends, not real dividends.

All these things are important but in the end, the question is have we managed the affairs of the Company so that the stock market - so that every dollar retained we give back more than a dollar in equity market value. These numbers at the bottom, the two red numbers at the bottom, mean that they retained a dollar and the actual equity market value went down. Some of the numbers like $0.25 means they retained a dollar and gave back $0.25.

We would view that as not particularly attractive to shareholders. And as you move up the line and into the $1.50, $1.60, there's really no correlation to anything you might do. The two best companies, us and number A are very lightly leveraged. This isn't a result of leverage.

Companies at the bottom of the list are high shareholder, high stock re-purchased companies. You have to be the luckiest person in the world to be able to generate two times your money by stock repurchases. You have to either be lucky or smart. We'll write off the smart and we'll say we just don't believe there's that much luck. Share repurchase program will not generate stock market value like this. If you have extra money, something you might do but it simply will not do this.

Our goal is to double your money. Every dollar we keep, give you back $2.00 in stock market value. Share repurchase program simply will not do that. If we've got no other choice, you should want us to - if we can do this, you should want us to reinvest in the business and not buy stock back.

Finally, off the soapbox, I'd like to talk about our investment attributes. Our business will grow 5% to 8% a year over the next five years. We have an opportunity for additional volume growth well in excess of this for probably well in excess of what we've shown you. We will continue to grow our dividends, we have significant financial flexibility for opportunities both in the stress period and for out of favor assets. Our financial statements are conservative, we think, a low amount of PUDs and a low probability of a negative surprise in some big write-off.

Our returns on invested capital are significantly in excess of our cost of capital. We can't make them too high because you're passing up opportunities but we think we're well above our cost of capital. We're committed to generating stock market values which is greater than the money we keep. And we all believe that this will generate top quartile returns for the Company over the next five years. It will probably be greater than what we generated in the last five. Thank you.

QUESTIONS AND ANSWERS

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

We're ready to start with our question and answer session. I'd like to ask that you direct your questions to me at the podium and I will direct them to our management team. When you're called upon, if you could state your name and company affiliation that would be appreciated. Thank you.

Doug Leggate - *BofA/Merrill Lynch - Analyst*

Thanks Chris, thank you everybody. It's Doug Leggate from Merrill Lynch. I want to ask two questions, first of all about California. If we were reading correctly what you're saying, you basically have 50 prospects at the minimum of a hundred million barrels per prospect. That's a 5 billion barrel of backlog. How are you risking that in terms of how do you get the one and three that you're saying is your success rate so far?

And if I'm not mistaken, and presentations are on the corporate results, you talked about 11 discoveries outside of the core well discovers. So can you quantify where you are now in terms of the prospects you've actually drilled out instead of what you're actually sitting on out there right now? That's my first question.

My second question goes to a comment Steve made about if we presented the numbers we really thought in California, they would look ridiculous. Can we just talk about how you are risking your shale opportunity in terms of the acreage you have is one number but you're not telling us how you're risking that in terms of the production potential of the shale going forward. So if you could quantify that as well, that would be great.

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

I'll let Anita answer the first question on the conventional and then Todd can jump in on the second one.

Anita Powers - *Occidental Petroleum Corp. - EVP - Worldwide Exploration*

First off, the 50 prospects stands at the range of place that I presented to you. The discovery play, the high potential and the bread and butter so all 50 prospects do not average at the 100. Secondly, the success rate of the wealth that we've been looking at and we've seen in previous disclosure 39 while 12 of which have been successful. We're not really ready yet to give a number because we're still evaluating the success.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

I assume that we only found three. And that's a small size, smallest part of the size of conventional and I think I had about two successes in the shale's. A lot less than - it's probably on the shale's maybe 10% of the 15%. And on the prospects, just again three's fairly small prospect successes. Otherwise, the numbers when you do this sort of making wedges, you wind up with something that it'd be good if it happened but it's a fairly conservative view of what we think the potential would be.

Arjun Murti - *Goldman Sachs - Analyst*

Thanks Chris. It's Arjun Murti with Goldman Sachs. Just a follow up on the shale potential, thanks for all the detail. Can you just talk about where you'll be in terms of rate counts now, year end, next couple of years and what the gating factors are towards a more aggressive or less aggressive program? In Kern County you've got a built in gas plant and the Permian you had Co2 consideration. You certainly sound like you've got your arms around the shale potential, what causes these wedges to be bigger versus smaller.

Todd Stevens - *Occidental Petroleum Corp. - VP - California Operations*

From our standpoint it's going to be driven by -- we want to take a measured approach and we want to be sure what we're doing. We're just not going to go out there and poking holes everywhere. And we've done quite a bit of work and we think following up our 3D seismic shoots helps us fix the best places.

And so I think you'll see us follow on the program when we shoot 3D we follow on shortly thereafter and look for the attributes we're looking for that we think will make us successful. And the rate count, we have the types of rates we need to do the program in the state of California. And I don't think that's going to be an issue for us.

Arjun Murti - *Goldman Sachs - Analyst*

How many rigs do you have in the state now Todd?

Todd Stevens - *Occidental Petroleum Corp. - VP - California Operations*

In the state, currently we have 11 rigs working.

Arjun Murti - *Goldman Sachs - Analyst*

And in terms of the 870,000, I think you described that as the more perspective areas, it sounds like there could be additional acreage beyond that but at the 870, are you risking that 25%, 50% some number you think is more likely to get you those DORs that ten acre spacing?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

We're really risking it way down. Way down, I mean I don't know what the number would be but maybe -- we're just taking the stuff Todd identified for the next few years and saying we have a pretty modest success rate associated with that. You take those kinds of production rates and you drill 50, 60, 70, 100, 200 wells.

Even with the declines and decline rates we're showing, it gets some pretty fancy production numbers pretty quickly. I think doubling California production in five years, which is what we're showing, is pretty -- would be a pretty good outcome. To show it would triple, I think, we'll live with that problem.

Paul Sankey - *Deutsche Bank - Analyst*

Hello, Paul Sankey at Deutsche Bank. You talked about an international return of 20% plus tax, can you confirm that Iraq meets that target and how we get there and can you talk a little bit more about what seems to be an un-risked or [rate] volume against the heavily risked California volume? And what is your thinking is behind that? Thanks.

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

Sandy would like to answer that as well as Dr. Irani.

Sandy Lowe - *Occidental Petroleum Corp. - President - International Oil & Gas*

Iraq just meets our hurdle rates. And it's a function of a quick payback that we get. 15% of the production goes towards payback.

Paul Sankey - *Deutsche Bank - Analyst*

If we had to get a rule of plans there we end up - and given that you will cooperate in seeing we end up at 12 million barrels a day in oil production. What's your view on how we should risk that and how that would be -- how we should risk that in your own outlook?

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Let me help you with that. As Sandy kind of emphasized, the folks who have gotten contracts in the region, Exxon, BP, et cetera, are cooperating to put together a facilities and the services required to develop all that stuff. Now is there going to be 12 million barrels down the road. Iraq's got plenty of oil, if you can get there. When it happens in X years is a different question. I think it will be slower than people anticipate, just because of the mass of development.

Regarding returns, I can assure that the returns we anticipate on the cash we spend is very attractive because the pace of the investment will depend on the development of infrastructure and of course securities situation. So the returns on the cash invested is attractive and you really have to look at the return then only as a good return on the project we have.

But to emphasis, if it's located in an area which is unequal, in my opinion, anywhere in the world, these are the opportunities. Until Saudi Arabia decides to open up its country. And that's not going to happen too soon.

Paul Sankey - *Deutsche Bank - Analyst*

Let me bring it all together, we should be risking Iraq downwards and risking California Rockies?

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Well, you can do anything you want but what we have tried to summarize for you is a conservative 5% to 8% growth with returns, after tax, in excess of 50% and as Steve said, those growth projections are on the conservative side.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

I think on Iraq, 50% of the excess goes to cost recovery. So if you do the arithmetic, over the 10% Sandy showed you -- if you do the arithmetic you don't really have to get a huge -- you don't get to all of the high numbers.

So I wouldn't risk it too much because a lot of that 75,000 cost recovery barrels and so the actual production doesn't really have to be the advertised gross to get there because you quickly become limited by your cost recovery formula. So I'd be cautious about being on the riskiness at 75,000 because pretty likely you'll get to the 75,000 with the cost recovery barrel. Even if the gross is off the numbers that Sandy's shown you. If you're going to risk it, I wouldn't risk it by a whole lot.

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

It's a very attractive long-term project where you make money during the time that you are developing it.

Robert Kessler - *Simmons & Co. - Analyst*

Thanks, it's Robert Kessler from Simmons. Oxy still seems fairly cautious on your outlook for natural gas prices which seems prudent to me in the near term, next few years. And of course fairly optimistic on your California oil or shale opportunities are 50-50 opportunities there.

So it's interesting when I look at your CapEx pie chart, the biggest wedge to increase is the midcontinent and cash which, if I'm doing my math right, looks like an incremental $480 million per year spend rate for the next four years or so there. And I'm just curious if you could maybe further define the rate of change there, how much of that for example might be oil inhabitant stuff.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Well the growth in earlier years is the oil and you get to -- we don't -- well we're not real excited about natural gas prices for the next couple of years. As gas prices move through $5.00, that doesn't strike as a particular aggressive position. We're going to spend a lot more money to put a lot of rigs to work there. Maybe that will keep the gas prices from going up but a lot of that is backend loaded compared to some of the others. It looks like a big increase because it sits from such a low base today.

Robert Kessler - *Simmons & Co. - Analyst*

Do you have a 2011 total CapEx number you're willing to throw out? For the Company?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

No.

Robert Kessler - *Simmons & Co. - Analyst*

Rough order of magnitude, another 10% off the 2010 or more than that?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

To some extent it depends on the pace in Iraq, I think is one factor that I'm not able to judge very well. The domestic business will probably boost to the level of the five year average implies.

Faisel Khan - *Citigroup - Analyst*

Faisel Khan with Citigroup. I was wondering if you could stack up for us what you think - how Iraq stacks up in terms of creating a profitability and returns compared to your other projects in the Middle East.

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Talking about Iraq specifically, I want to re-emphasize we're looking at this long term. If you're talking about short term, it's attractive but it's not completely going to give you the returns we have gotten which is over 20% average in the past. But it's high risk and we think to get high return in a project that has tremendous long-term potential is a good place to be. Good store hold, other opportunities will come along.

Faisel Khan - *Citigroup - Analyst*

Okay. On the Co2 you talked about how your Co2 consumption per barrel of oil is actually coming down in the Basin. Can you talk a little bit more about what's driving those productivity gains in the Basin? And with the stock, given that you're moving into other parts of the field of those productivity gains whether they'll flatten out or dissipate. But it sounds like things are getting better.

Bill Albrecht - *Occidental Petroleum Corp. - VP, President - US Oil & Gas*

Yes, I think they're getting better, a little bit better. Primarily because we're putting a lot of this Co2 away in our legacy fields that are not fully under Co2 flood now, so that's where we're expecting the greatest benefit in Co2 is from our legacy assets. It's just a simple expansion of those assets and I think that as you move out, expand those floods, we can certainly expect to get the better than what I threw out, six to one ratio, just because they're in legacy fields that have been proven to work.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

We're running about four currently in those fields. So it is getting worse, sort of. Just going from four to five or six.

Faisel Khan - *Citigroup - Analyst*

Okay, and last question on Oman. I guess, first of all, how much gas are you consuming from Mukhuizna in order to get workover flooding and how do you view the availability of supplied natural gas, pristine generation and in the field -- do you feel secure? Do you have enough supplies of gas going forward?

Sandy Lowe - *Occidental Petroleum Corp. - President - International Oil & Gas*

I think the total of consumption is probably a number that is confidential with our contract with the Omani but I can tell you that it's running a fair bit under what we projected because we're using heat recovery steam generation folks from our existing power plants but also some power plants that develop electricity for other fields in the area. So we have more cost effective steam heat available to us and the contract requires that the government does provide us the fuel gas. So we have no issue with that, there's no indication we won't get all we need.

David deWitt - *Morgan Stanley - Analyst*

Hi, my name is David deWitt from Morgan Stanley. My question relates to the Kern County discovery where you said you'd only been able to delineate one side of the field. My question there is the discovery a stratographic trap?

Anita Powers - *Occidental Petroleum Corp. - EVP - Worldwide Exploration*

No.

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

Next question.

Kate Lucas - *Collins Stewart - Analyst*

With California being such a large part of your growth outlook going forward, do you have any concerns about any changes in physical structure just given the state budgetary outlook?

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

I think a few people could add to that. I'll go to Bill first.

Bill Albrecht - *Occidental Petroleum Corp. - VP, President - US Oil & Gas*

Well, obviously given the California budget situation, there's been talk of a severance tax imposition which has been repeatedly voted down by the California state legislature. I'm sure they could come up with some other taxes, they've been apt to do in the past, but so far the main culprit there is the state severance tax imposition and that has been repeatedly voted down by the legislature. Does that answer your question?

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Let me add to that. The economics of our California development are so attractive that even if the most absurd regulatory factors were imposed it would still be a very good investment. Right now I'm much more concerned about increased taxes in Washington, rather than California.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Might create opportunities to get some more acreage in California. Maybe scare out some small producers.

Tom McNamara - *Impala Asset Management - Analyst*

Tom McNamara from Impala Asset Management. For the California unconventional plays, how does success correlate with 3D seismic in terms of interpretation of your 12-36 approximately? What had 3D on it and has that changed much as more 3D has come in?

Todd Stevens - *Occidental Petroleum Corp. - VP - California Operations*

It's helped us to build reservoir, I understand natural fracturing. I'm not --.

Tom McNamara - *Impala Asset Management - Analyst*

Are you running higher than a third success rate with what you've got 3D seismic on?

Todd Stevens - *Occidental Petroleum Corp. - VP - California Operations*

No.

Tom McNamara - *Impala Asset Management - Analyst*

Thanks.

Pavel Molchanov - *Raymond James & Associates - Analyst*

Pavel Molchanov with Raymond James. On the OxyChem you eluded to the above average profitability metrics of the business and since potential buyer might look at it much the same way, my question is under what circumstances would you sell chemicals?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

A large check that gives us a lot of after tax cash proceeds. I mean you have to replace the cash. Not a lot of evidence of selling down a bunch of stuff improves your business but the chemical business is a profitable cash flow -- cash cow business. Almost anything that somebody writes a big enough check we'll sell but it's very hard to replace $500 million to $600 million a year of free cash flow with a very low capital program. And really not very exciting --.

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

I think it's exciting with all that cash flow coming in.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Not as exciting like California.

Bob Morris - *Citigroup - Analyst*

Thanks, Bob Morris with Citigroup. Steve, you mentioned Phibro but you really didn't say a lot about it. Could you just give us a little bit more color there? How much capital is within Phibro, how are you managing the risk there and sort of what's going on with that?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

We've got about $250 million in it, which is what we said. We have pretty good risk controls and it has been a choppy quarter for them as you can imagine. It's fine - you should view with really a long basket of commodities, sometimes you go on cash, sometimes you use along the commodities. He's been in and out of several commodities in the last year. Currency used more recently.

It's really a very small business, you got $250 million capital, and we have $32 billion of stock holder's equity. Analyst numbers show our cash from operations $7 to $8 billion, whatever it is. This is going to be a couple hundred something like that maybe. So it's a pretty well controlled but a small business. It's very profitable but it is a small business. People don't ask about the calcium-chloride business we bought, which is a $200 million business and I'm getting good returns so we'll entertain questions on the calcium-chloride business along with Phibro.

Bob Morris - *Citigroup - Analyst*

My second question was, you mentioned your goal is to get back at least two to one on the shareholder value from the equity in the Company and that you left the share repurchases last on the alternative for excess cash. A few years back you were aggressively repurchasing stock. What would be the circumstances for you to return or resume repurchasing stock?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Well I would hope that we would find the opportunities to invest in the business, we'll start with that. If for some reason we couldn't and the stock price were -- I mean we bought the last slug at $58.00 and the slug before that some years ago we bought it at $13.00 or something like that. $14.00, on a split basis.

So it's been okay but there were obviously some trades in the last slug that I wasn't all that excited about. But I'm responsible for. So it's just hard to say because you're really sort of looking and saying, I know what the stock price ought to be and I have a whole room full of people here who have a different view than I do probably.

We don't know. I think we'll tell you when we get there. We're going to try to avoid doing it when the -- you're always tempted to do it when you have a lot of cash, which is really almost the wrong time to do it so we'll try to be better this time.

Bob Morris - *Citigroup - Analyst*

Thanks.

Jason Gammel - *Macquarie - Analyst*

Thanks, Jason Gammel with Macquarie. A couple of questions on Bahrain. I'm assuming resource potential that your production outlet is probably constrained by market, that might not be correct but if it is a market constraint can you talk about what incremental opportunities you've exceeded cell gas in the region? And then as a following question, if you're successful in the work of the pre-cook exploration rights, what market would you look for that gas?

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Well Bahrain, as you know is an island. It does have a bridge to Saudi Arabia but the growth that Sandy showed you is totally for internal consumption. The economy is growing very fast, there's a huge naval base there - United States Naval base, and they've been growing well and so there's no need to sell the gas externally.

With regards to additional gas that may be discovered and we do have exploration rights offshore Bahrain. In addition we're competing for deep gas which will be award in the third quarter and I'm somewhat optimistic there that we'll get it. If large reserves are discovered, then you start talking about exporting it in all kind of different ways. Some of the markets you can supply with a pipeline. Others, if the discovery is large enough, you might look at LNG. But that's in the future.

Evan Callio - *Morgan Stanley - Analyst*

Evan Callaway, Morgan Stanley. Let me ask the cash question maybe in a different way. Given your proclivity to reinvest capital into the business and let's assume that California's higher in your overall relative return opportunities set. How quickly in a higher place commodity environment could you put capital into that business? How much more capital do you think you could put against the California opportunity in the right environment?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Couple billion dollars a year or more.

Evan Callio - *Morgan Stanley - Analyst*

Thank you.

Faisel Khan - *Citigroup - Analyst*

Faisel Khan from Citigroup. Just a follow-up question on Midstream and Chemicals. You're talking about doubling your EBIT in which stream over the next five years. Is that mostly from the new Co2 plant and pipelines or is that -- what's the drive in that doubling of earnings?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

We're investing in a fair number of gas plants and there's -- the way those GPs work in the -- you're going to get more and more cash out of the Plains GP. And there's some other smaller opportunities around that we see around our asset base basically to add more processing or pipeline capacity in the next couple of years. There's a lot of really nice, small opportunities that we can make a 20% return on.

Faisel Khan - *Citigroup - Analyst*

And on the chemical side, is that mostly recovery in the economy and volumes?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Recovery in economy and volumes and it estimates that the natural gas prices on a world basis will still be attractive in the United States. With the amount of gas that's around the United States is probably a pretty safe bet. As long as it stays relatively attractive to the chemical business, we'll do very well. As long as the world economy isn't too bad.

Faisel Khan - *Citigroup - Analyst*

Thank you.

Phil Dodge - *Tuohy Brothers - Analyst*

Yes, Phil Dodge, Tuohy Brothers investments. In Argentina, do you have an estimate of how much you'll be able to book in additional reserves if the contract is extended for 10 years?

Sandy Lowe - *Occidental Petroleum Corp. - President - International Oil & Gas*

$72 million.

Doug Leggate - *BofA/Merrill Lynch - Analyst*

Thanks Chris. Just a follow up. Pardon me for being dumb but I'm trying to understand this shale situation a little better. So let me get this straight. 870,000 acres you're risking, as Steve you said 10%.

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Yes we're risking not the 870,000 but the 10% -- the 10% to 15% I'm risking 10% for this period.

Doug Leggate - *BofA/Merrill Lynch - Analyst*

So at 400 barrels per prospect, sorry for the well. What do you -- how many building locations do actually you have in the California shale and the risk basis?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

About 300.

Doug Leggate - *BofA/Merrill Lynch - Analyst*

Okay and you're running 11 rigs on that program right now?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

Some of it's in build numbers because some of it's the stuff that's already there so on the new ones about 300 would be a safe --.

Doug Leggate - *BofA/Merrill Lynch - Analyst*

So we can do our on math then, how many wells are we looking at per year roughly on that program?

Steve Chazen - *Occidental Petroleum Corp. - President, CFO*

At least, from the perspective of now, if we do better obviously we'll boost the number. That's all that's in the model if that's the question.

Paul Sankey - *Deutsche Bank - Analyst*

Yes, follow up from me, Paul Sankey . Is there any expected impact from the recent shareholders vote on the say-on-pay?

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Let me try and answer that, the say-on-pay vote indicated that the majority of our shareholders are not approving the current policies that we have vis a vis pay. And our Board of Directors take shareholder's views seriously so they are studying what changes may have to be made and we'll be meeting with different investor groups over the next couple of months to determine what changes may have to be made.

Paul Sankey - *Deutsche Bank - Analyst*

Well, one logical conclusion may be that the dividend growth, which is already rapid would be even more rapid, is that reasonable conclusion?

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

I don't think those two are tied together but I think that we look favorably upon dividend growth, as we said, and rates very high on our scheme of things and use of cash. Last year was very modest and we think looking forward the 15% compounded may be on the conservative side, especially with the big success we expect out of California.

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

Other questions?

Robert Kessler - *Simmons & Co. - Analyst*

If memory serves Dr. Irani, four years ago in this setting I think you said, with respect to management's succession and retirement, if Oxy reaches one million barrels a day, perhaps that's the time to think about it. I think it was somewhat a joking comment, but it looks like on your slide it happens around 2012 or 2013 now, so just curious your latest thoughts? I mean obviously, Oxy's got more on your plate today, arguably, than you had then and you look younger now than me at least, today, but --?

Dr. Ray Irani - *Occidental Petroleum Corp. - Chairman, CEO*

Well, one of the objectives for having this many speakers, more than we've ever had before, to show you there's plenty of guys ready to take my job and since I do own personally, a fair number of shares out of my net worth it makes me feel good there's a lot of people working here that will do very well for me now and in the future.

Chris Stavros - *Occidental Petroleum Corp. - VP - IR*

Questions in the back? Going once, last chance? Well thank you very much for joining us. We'll adjourn now and there's a luncheon in the Versailles Room on the second floor so we'll see you there shortly. Thank you.
