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PRESENTATION

Scott Espenshade - *California Resources Corporation - VP - IR*

Good morning, everyone. I'm Scott Espenshade, vice president of Investor Relations at California Resources Corporation. And I would again like to welcome everyone for you attending in person as well as those listening in on our webcast to CRC's 2015 Analyst and Investor Day Part 2. This is Day 2, Number 2.

As a reminder, today's presentation contain certain projections and other forward-looking statements within the meaning of the Federal Securities law. These statements are subject to risk and uncertainties that may cause our actual results to differ from those expressed or implied in these statements we give today.

Additional information on factors that could cause results to differ is available on our company's 10-K, which is available on our website and the SEC filings. We'd ask that you review it and the cautionary statements in today's presentation.

You'll also be able to access today's slides under the Investor Relations link on the CRC website at www.crc.com.

We're thrilled today to be here at our Central Control Facility outside of Bakersfield to discuss California Resources and its northern assets in greater detail.

First, let me give a brief review of what we covered yesterday. Todd Stevens highlighted CRC's strategic objectives and the flexibility in our assets to be able to manage within cash flow in a normalized price environment, the ability to resume growth.

Also, California is again still the least understood world-class oil and gas-rich environment in the entire United States. We gave an overview on the California markets since regulatory regime. We also provide a primer on our waterfloods and then updated the market on the performance and cost savings seen in our southern operations. And there we noted also that big deals really do get bigger.

As for today's agenda, we will begin the day with Day 2 with presentations by the following speakers.

Darren Williams, our executive vice president of Exploration, will give an overview and to look into his portfolio.

Bob Barnes, our executive vice president of the northern operations will give an overview of San Joaquin, Sacramento, and the Elk Hills area and speak more specifically to our inventory in this location.

Dr. Vic Ziegler is director of Corporate Development. He's going to sort of give an overview on steamfloods, and then we're going to go into a little bit more detail on how we really look at the monitoring and surveillance of our steamfloods with Jeff. Jeff Hatlen is going to continue on that [brimer].

For those of you that are here today, we'll follow that (inaudible) of our Elk Hills infrastructure, and we'll get to look in an early stage steamflood for those that are participating today.

Today's presentation again is scheduled to last over two hours. With Q&A, probably add another 30 to 45 minutes. We please ask that you hold all questions again until the end of the presentation. At that time, please wait for the microphone to have your question captured for the webcast.

You know, one of the things we had yesterday as well, we had a lot of interest generated by this slide talking about our inventory. I'd like to turn it over to Todd to go a little bit more detail to provide a little bit more color.

Todd Stevens - *California Resources Corporation - President, CEO*

(Inaudible) and we didn't trip the flare for your entertainment, but the (inaudible) plant is back up and working, Bob tells me. So, it was just the high-level warm that went off.

This slide, I know a lot of you -- there's a lot of discussion on this and we wanted to clear things up so everyone understood. I want to make sure we go through it so that everyone is clear.

First thing the capital on here is drilling and basically D&C capital and workover capital. And this is what we're talking about here. But when we talk about the VCI greater than 1.3, that's all in, so these projects, that includes all the money. And the way they'll think about it is if you go back to our capital budget for 2015, we have about $150 million of drilling capital, about $50 million of workover capital, so this ties that $200 million of spending going forward, so that's what we're really talking about here. This does not have facility capital in it, but this calculation for the VCI metric does. So we're saying these are engineer ready-to-go projects with VCI is greater than 1.3, but this is only the D&C capital associated with those projects if you understand what I'm talking about.

And you heard yesterday when we are talking down south that, you know, we said facility capital historically is about 30%. We think going forward it will probably be 20% along those lines based on our calculation.

I just want to clarify, if there's any questions or comments on this and make sure everyone we're clear what this is and what it isn't at this point in time.

This is that slide that we're talking about here, the $440 million. So this is the drilling. This is the workovers. That's the $200 million I was just referring to at this point in time.

I cleared that up. Everyone squared away?

Yes, Sir? Back -- I'll repeat your question. Go ahead.

QUESTIONS AND ANSWERS

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

On slide 17 what gas price is $3.

[Bryan]?

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

So, on slide 17, he asked about are all these projects are very much different, but the idea is along...

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. It really is a -- rig count, I mean, this year obviously we're doing it with three rigs. It can vary because it depends on the type of projects you're going to go do. Steamflooding, you're going to drill a lot more wells. If you're going to drill an intermediate well somewhere else, it could be different. So, the rig count could be three. It could be 10 depending on what kind of things you're chasing at this point in time.

Yes, Sir?

Unidentified Audience Member

(Inaudible) the $100 million (inaudible) increase the D&C, that (inaudible).

Todd Stevens - *California Resources Corporation - President, CEO*

No, no, I think if you -- the question is really going from $500 million next year to $600 million, $700 million long-term. I think there's a combination of factors involved there. Some of that is facility spending. Some of that is [air bar], so we're trying to be correct based on what we know today predicting the future so there's an amount in there that you could say over time with certainty it's going to come, and it's probably going to come down. But there is some element of facility spending that's going to be slightly higher, but then the rest of it probably will come down over time, but that's what we're saying. To be certain it's about $600 million.

[Doug]?

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

The question is you have the $600 million, $700 million, but you didn't have the expense workovers is what you're saying.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

Didn't have the capital. You have the expense workovers. I think you're going to have, you're going to be in that decline rate. We talked about 10% to 15%, but you're probably going to be -- because you are spending the money, you'll probably going to be closer to 10 than you are to 15 because of this expense workovers.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

That's why we have this chart here showing depending on what type of rigs you use, this year we're $150 million of drilling capital, so drilling rigs we're using three of them, $50 million of each. That's kind of the rounding I gave you yesterday, but these are effectively all pretty shallow rigs.

So if you start talking about more expensive rigs and drilling deeper wells, you could grade it to the $60 million, $70 million a year of spend. But I think if you thought about it, adding a shallow rig generally is going to cost you about $50 million a year going forward.

[Chris]?

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

So, the question related to the Brent price and then how many rigs each time we keep production flat, I think generally it depends on the product price environment. So, the gas here is $3. We're holding that static. And these environments obviously, all steamfloods are going to be highly economic, so you're going to be using more shallower rigs there, so you're going to probably be on the lower end of the kind of rig years when you think about it there because you're going to drill a lot of wells but with just a few rigs.

But it will change over time as you get into these because you start getting into unconventionals using different types of rigs. You're going to use (inaudible) rigs and some of the more sophisticated horsepower equipment.

So, yes, it's going to vary. There's no perfect answer.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

Yes.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. I mean, if you think about it from the standpoint of looking at the slide, I can't remember the number, it was like my second to the last slide yesterday, so it was around 37 or something like that where we talk about inventory. You could argue that that inventory at a 1 VCI, which is a 10% factor built-in.

I think with the 1.3 is correct. This is a little philosophical discussion. But when you think about our industry, it's a capital-intensive industry, and what you do with the capital is how you create value or display value for the long haul.

And I've seen a lot of companies chase the wrong priorities and that creates production. It creates short-term cash flow. It does things, but it doesn't always create shareholder value. And over time I really felt like the way [tentacle] has run and the way Harold ran southwestern that you created a mechanism that forced the enterprise to create value for the shareholders over the long-term and you high-grade those projects. You do the things, invest the dollars over the long-term that ensures that you create value. And I think that if you run the enterprise that way, you're assured to ultimately create shareholder value.

Scott Espenshade - *California Resources Corporation - VP - IR*

And, [Doug], your question, you're previewing one of our slides actually. You'll see in Bob's presentation today, he shows the comparison in Elk Hills of VCI at 1 versus VCI at Tier 1.3 to show the additional inventory that's there.

So this is a high-graded inventory list that meets our investment threshold of 1.3 or greater. So, there's more inventory behind this. It's a static look. It is a dynamic process that mean as we showed yesterday with Frank's slide down in Wilmington that new activity begets new additional activity. So between your drilling and your human activity, you're able to add locations at a very mature field like Wilmington. The same is true for us through our portfolio.

Todd Stevens - *California Resources Corporation - President, CEO*

Any else (inaudible) competitive, Bob will give you an example talking about our Mount Poso field how this year if they had a 1.3 VCI, but they still weren't competitive for dollars when you rank high-graded the portfolio because we have so many projects that can compete, and so they kept working on the project until they can compete for rig time.

[Evan]?

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

Resource size behind this is Evan's question. And I think that it's a huge number. I mean, you go back to my slide on $40 billion in place, 22% recovery currently. And I would argue, and I think Bob might even hint at this a little bit that particularly in some areas where there's been less G&G and less engineering, modern engineering work done, the oil-in-place numbers are artificially low, and they're based on 1970's estimates in some cases. So, that's why sometimes you get some goofy recovery factors that [look off].

So I think the resource here is enormous and you could look at it from the standpoint of our 3P reserves at this point in time. But I would say that the recovery factors are artificially low in oil-in-place is artificially low also.

Any other things on slide 17 before I turn it over to Darren? How will it turn it over to Darren here? Here you go, Darren.

PRESENTATION

Darren Williams - *California Resources Corporation - EVP - Exploration*

Thank you, Todd. Appreciate everybody being here today.

My name is Darren Williams, and I'm the EVP for Exploration. Fortunately, someone set me up to actually give my resume a little bit yesterday, but just to recap, I guess, I've been in the industry around 21 years. I'm one of the new members of the team, having been on board just over 12 months. And really I've been a career explorationist basically working basins onshore and offshore both domestically and internationally over the course of my career.

But as we heard yesterday, one of the other key components of my background is that it's been three years essentially working a resource play and led in established marathons, Woodford Shale Development Program up in Oklahoma City and basically set the groundwork there for what became the scoop-and-stack play is today.

So, as we go through my presentation today as you would expect, one of my key takeaways is going to be able to communicate to you the kind of robust portfolio that we have within the exploration assets, and really the demonstrated success that's being created over the last few years. In addition, I'll discuss unparalleled conventional exploration portfolio.,

It's worth noting that our portfolio has over 125 independent oil and gas prospects that all have stacked pay potential that generally -- is this still working? Okay. Well, switch to the other microphone -- all have stacked pay potential and are improving reservoirs that are generally directly analogous to either producing fields or some of the key discoveries that we've had to date. In addition, we've already had some discoveries as a group on the option value and long-term growth that exist within the shale reservoirs. And I'll provide some more detail on the prospective reservoirs that exist within our unconventional shale portfolio.

And then finally, I think one of the things that's key to what we do as a team is we have such a large and diverse set of opportunities. One of the key things we try and employ is just the rigorous portfolio management process that's focused on value creation and basically utilizing that to drive or exploration program.

Firstly, I would just like to provide some context, and this slide is one that you've maybe seen previously that really describes the exploration history of California.

When you look at this data there's a few key points to take away from it. Firstly, the total discovered resource for the California basins where CRC operates is greater than 37 billion barrels of oil equivalent.

You've heard already the terms that this is the world-class hydrocarbon province, and this data really is what goes to make the basis for those statements.

And then secondly, as you start to move into the exploration program and growth potential, what I'd point towards is the creaming curve or the red liners on these displays. And when you look at that, it's essentially being flat since about the 1970's as there's been limited exploration activity.

Generally, when you look at a flat creaming curve, the view could be that this is a basin that's being fully delineated with limited yet to fine resources. However, when you start to understand the story about California, you kind of hear some of the comments that Todd and others have made previously about California being the time that land forgot. You start to realize the opportunity set there as it presents itself in California.

So when you look at these curves, you have to take into account the lack of exploration activities since the 70's, the lack of modern technology that's been applied when you look at these discoveries, many of them were made on surface information, either [seeps] or as you drove up you will see the big hills and people just drills on top of the hill. And then some cursory 2D seismic in the middle of the last century.

And then on top of that, I'd also look at just -- I'd point out the gradient of that red line when you go from the 1870's, 1880's and just look at how it continues to build up through the 1990's and then just flat lines. And that really shows you that growth potential that was delivered by these basins and then just stop as activities started to stop. That really stops to define the opportunity and the potential (inaudible) existing California.

And then on top of that where I would layer in is if you look at the chart on the right-hand corner, you see CRC starting to validate the potential that may exist as we've had some sustained discoveries over the last few years that's driving a breakout in the creaming curve and continuing to add new resources.

Slide 8 starts to really expand on those discoveries and starts to communicate the value creation that's being delivered from the exploration program historically.

Since 2007, the exploration program has drilled over 100 wells with almost every well encountering hydrocarbons. From a fuel statistical standpoint, we have a geologic success rate of 70%, which when you look across the industry and use benchmarking studies like Wood Mackenzie, that's almost twice the industry average that they have of 40% geologic success during the same time period and basically places CRC in the top quartile in terms of geologic success.

The chart to the right start to show some of the organic growth from a production and reserve standpoint that's been generated by this program. The chart in the top right-hand corner shows the gross production from new discoveries that's ranged from basically around 18,000 to 25,000 BOE per day in the last few years. If you pull that in perspective, that's essentially around 10% to 15% of the corporate production profile that's been generated from exploration discoveries.

In addition, the program isn't just adding resources, it's adding reserves. And then the chart in the bottom right-hand corner, you'll see the cumulative reserve has been made. And I will point you to the dark blue bar, which is the proven reserve which basically have totaled just under 100 million barrels.

These rules have been delivered by sustained success. And you can see on the slide deck some of the discoveries that are factored into this. These discoveries are diverse and really are in multiple different play trends.

Going back to Gunslinger, that was a large four-way structural closure, which have multiple stack reservoirs. In 2012, we basically integrated and used our proprietary 3D seismic data to identify the B.V. Nose stratigraphic trap, which is on the flanks of the legacy assets.

Using proprietary geologic models, we've successfully extended the Pleito Ranch field both in 2013 and 2014.

And lastly, as we announced in our Q2 earnings, our most recent success is from another stacked pay discovery, which flowed at rates in excess of 750 barrels of oil a day from one reservoir into.

In a second, I'm going to start putting some more perspective in terms of the exploration portfolio and start talking about key play trends. Each of these discoveries lie in one of those separate key play trends.

When you look at what has enabled us to have that success and really drive the program, really our 2.3 million acre land position provides us that basic license to explore. We build up a large contiguous exploration land position that really allows us to control the basin and drive the activity, and the success case that land position also allows us to go out into harvest mode and follow-up, and capitalize on any success by drilling offsetting explorations prospects.

In addition to our land position, we have proprietary data that is not available to other operators, and that provides us with a significant competitive advantage.

As an example, we have over 90% of the 3D seismic that's available in the state. We reprocess to merge those data and it allows us to create large regional data sets that allows us to view the whole basin and be able to put prospects in their individual perspective.

While our land position in data is key, the other factor for us is the basic technical capabilities of the team that we have. There you'll see just the breakdown of the experience and the picture of an outcrop.

As you drove up here you will have seen pretty interesting looking mountains and really, those are the reservoirs. We have some coal laid out up here, which kind of gives you some more details of reservoirs. But California, we're kind of real lucky that we can step out and see the reservoirs within a short drive from where we stand today.

So basically the technical professionals that use slides and all the data that we have, they're integrated in the outcrop data, and they're building proprietary geologic models. And almost to a [T] those models have allowed us to identify these new resources that make discoveries over the last few years.

Really, I just want to step back and start to look forward and give some details on the actual exploration portfolio that exists. As I said, we believe the portfolio is unique and unparalleled amongst our peers. And when I say that, it's worth thinking about a few things. There's no peer company that has the materiality of CRC's conventional exploration portfolio in an onshore U.S. setting.

What I would say is if you were to start looking for an analogue from a domestic standpoint, you will be looking out in the Gulf of Mexico. Alternatively, if you are prospecting on an international scale, you must likely be in some high-risk frontier or emerging basins where the presence of hydrocarbons may not have even been established and other significant aboveground risks likely exists.

So really when you look around on a worldwide basis and consider the exploration portfolio that exist within CRC, it truly is a differentiator and unique. There's lots of companies going to far-flung places, remote and hospitable places trying to find opportunities like this. And really California is somewhere that offers some very unique and large upside.

The display on the right here starts to give you a little bit of a cartoon of some of the play types that we deal with, and really is a representative of the San Joaquin basin specifically.

When you look on the left side of this display, you'll see some very large structurally controlled four-way closures, and effectively was stood on top of one of those today as we're over in Elk Hills and on the west side of the basin. These plays are generally characterized by the potential for multiple stacked reservoirs and the opportunity to stack multiple prospects underneath each other.

We've also had a lot of success in the Pleito trend. And if you were to look at this cartoon, Pleito is a sub first play, which would sit on a location just like this.

As I mentioned, we have extended the Pleito trend both in 2013 and 2014, but not only did we encounter hydrocarbons in the primary reservoirs, but we also proved that pay in some secondary targets, again demonstrating that potential in these fields with some stacked pay potential.

And then as you move out into the basin, you get into some different play types here. This is where our seismic data sets really come into play as you get into stratigraphically controlled and seismically defined prospects such as those in Stevens sands. They're analogous to the B.V. Nose discovery that I referenced early, too.

In addition, I think it's probably worth pointing out as we stood here on this slide, I think I've heard probably a couple of comments around structural complexity and being an issue for the shales in California.

What I would say is a lot of people think about these areas relative to the shales in California. In reality, when I start talking about the shales in about a few minutes from now, we're really looking out in the central basin area where the structural issues are a lot lower.

That's just one representation from a cartoon of some of the play types. In addition to those represented here on the schematic, we also have a set of heavy oil prospects. We have opportunities in the Ventura Basin and multiple different structural trends that forms some large regional play types. And then in addition, we have significant potential in a multitude of gas prospects in the Sacramento Basin.

I think yesterday if you relate the prospectivity in the different play types I just described in some of the fields that you've seen to date and then go back to the chart that Todd showed, which have the four quadrants and the ability for the different levers that we can pull in different price environments, the same opportunity exist within the exploration portfolio as we go from heavy oil prospects, conventional/unconventional reservoirs just in stratigraphic, constructural traps, and then all the way to some gas prospects. It really provides us the opportunity to support the development programs and really have an opportunity funnel that drives our success.

Slide 11 -- oh, sorry, slide 13 because we got two new ones in there, starts to give you some statistics and some more information relative to the portfolio.

As I say, CRC truly has a material low-risk conventional exploration portfolio that consists of over 125 independent oil and gas prospects. Those prospects have distributed across 10 key play trends in three world-class basins.

The clear strategy from the exploration program is not only to deliver success but to deliver value-accretive success. And the two cards on the right of this slide demonstrates some of the tools that we utilize to drive our program and investment strategy.

The upper chart shows the resource potential versus CRC's demonstrated commercial success for our oil-focused trends. Using this kind of display, we can high-grade and differentiate opportunities both on a risk resource and repeatability basis. Each bubble on this chart relates directly to a key play trend like the ones I've just talked about, and the scale of resource that is available in some of those plays is displayed on this trend or this slide.

What I would highlight in addition is there's a small green star in the bottom left-hand corner. Again, if you go to some of the industry benchmarking studies, you can see here we have WoodMac's commercial success rate and average discovery size plotted on this chart. And when you plot the opportunities what we have in perspective, the resource potential as well as the demonstrated commercial success that we have delivered, you can start to see a lot of the portfolio truly outperform industry average.

In the second chart in the bottom right-hand corner, we show a tool that allows to high-grade and differentiate opportunities on a risk value creation basis. On this chart, we show the risk case F&D versus VCI. This chart deliberately has no scale on it. It's not just to not give away the information, but also it's because this chart is evergreen.

Again, if you relate this back to the four quadrants charts and different price environments, this chart is one that can be constantly changed in either based upon new information or different commodity prices. But really the key message here is that we utilize in these kind of value-driven tools to really guide how we execute on the exploration program.

In terms of some of the success that we've had here in the (inaudible) we really communicated the recent results that we'd had in the summer, and slide 14 provides the details on that success.

This well also gives us an opportunity to talk about selling slightly different as this was drilled as an exploration [tails] with development well. Due to the stacked nature of the reservoirs that we have within California, we can often do some cost-effective exploration by drilling deeper within existing fields based upon plan development wells.

When you look at this well, if found multiple stacked reservoir interval is in a structural trap, the deepest reservoir had a peak daily flow rate of a little over 200 barrels of oil per day. This interval was flowed on pump for approximately six months and still had oil rates for approximately 100 barrels per day when we shut in for the completion of the second reservoir interval.

We set a plug and tested the second reservoir interval over the summer and that interval flowed at rates of over 750 barrels of oil per day and 1.5 million cubic feet a day.

At this point in time, the well is [choked back] from early production rates, but it still currently producing approximately 650 BOE per day. When you kind of look at this play trend in terms of repeatability, we really have significant running room in this trend. It's generally underexplored with less than five wells drilled in the basin to test these reservoirs. We see the trend extending for 20 plus miles. We have 10 additional follow-on prospects. And ultimately, the potential to drill deep still exists, and we have a net risk resource in excess of 200 million barrels.

So really that kind of gives you a flavor of the conventional exploration program. Really I'm going to switch gears and just give you a little bit of a taste on the shales and where we are with those.

Really, as we stand here today and you go through the slides, I'll just show this, our focus truly is on the value that can be delivered from our conventional exploration program, but we do see that option value and significant upside that exist within these shale reservoirs.

This slide shows a type of log that highlights the multiple shale reservoirs that exist within California. As Todd said and if you haven't been up already, we have cores laid out from the Upper Monterey, the Whepley, and the Kreyenhagen for the front. And it's worth seeing those just to see the difference from those purely from a visual standpoint.

When you look at this log, we have greater than 2,500 feet of exploration shale reservoir potential. And from a portfolio standpoint, we see over 2 billion BOE of net unrisked prospective resources within these shales over a 650,000 gross play trend.

You likely seen this slide before in other presentations, but this slide starts to give you that flavor for how the shales in California compared to other resource plays.

What you will see from a reservoirs property standpoint, in most cases, is that the shales have very similar properties. But one of the things that truly differentiates the (inaudible) on these shales is the scale of the thickness of the prospective section.

As you've heard previously, CRC is an established operator in unconventional reservoirs, and we currently produce 50,000 BOEs per day from the Upper Monterey.

At this point, we truly are being deliberate and, I guess, cost-effective in how we approach the rest of the shale potential. At this point, we're really focused on the Kreyenhagen as it gives us the opportunity to utilize legacy existing vertical wells and workovers to get and understand the reservoir variability and performance. However, when you look at the potential for the Moreno, the Whepley, and the Lower Monterey, we see similar reservoir properties that could have the potential to be future developments.

So I'm going to go through some pretty high level here of just some of the reservoir potential that we see specifically within the Kreyenhagen as an example of one of these plays. I can give you a flavor of what we see within California.

You know, when you look at these shale plays, the key factors is really about scale and repeatability and having an expensive reservoir is key to having that predictability on a large scale. When you look at the Kreyenhagen utilizing our log and seismic data, we can map an extensive reservoir that exist across this key play area where gross reservoir thickness is ranging from 500 to 1,000 feet.

Some of the other key factors that come into play in terms of assessing shale plays is total organic carbon, or TOC, affirm on maturity of those rocks. They really gives you the potential to understand how much hydrocarbons can be generated as well as what kind of hydrocarbons may be present.

When you look at the Kreyenhagen and it's shown on this log display here, we see TOC values that range from 2% to 8%. In general, a TOC that's greater than 2% to 3% is considered a good quality source rock. In addition, when you look at this log you'll see a scale in the center, which is the total thickness. It's not the depth, it's the total thickness. And what you can see there is the large-scale thickness that exist in this log as the reservoir is greater than 850 feet.

What I would say is if you compare this and look at other plays around the U.S., even in the cores of some of the real high-value plays that are out there today, you're looking at 300 to 400 feet of reservoir thickness. So when you put this Kreyenhagen in perspective, you can start to see that either you can say we have doubled the thickness or you can either say we have the potential to have two zones that could be equivalent to some of those other resource plays around the U.S.

On the right side of this display, you'll see a map that describes the thermal maturity based upon the calibrated geologic models that we have. Within this display, (inaudible) display that has the green, yellow, and red displays that will be consistent with other shale resource plays around the U.S., and you can start to see that we're able to define an oil condensate and dry gas window. In addition on this display, we have overlaying average TOC contours, so you can start to see a core area starting to develop. There is prospective the oil and condensate and has high TOC presence.

The last slide really is about describing the presence of a regionally extensive shale reservoir. Really once you get in to execution mode it's all about reservoir properties of that point.

The simple analogous or the simple analogy that we use is to basically relate it to candy bars. If you have a Butterfinger or if you have a Reese's Peanut Butter Cup, clearly, they're all chocolate, they're all peanuts, but they have very different textures. And the same issue is true with the shale reservoirs.

When you get into an execution mode and you want to get into doing well stimulation, you're looking for a rock that fractures, is brittle, has quite high quartz content and really can help you effectively drain your reservoir.

When you look at the Kreyenhagen here, we see average porosities greater than 10%. We have significant quartz content of 50% to 80%. I would point you down to here, you can start to see that 50% to 80% thing. When you compare that other shale plays, again a lot of them cluster around the 50% quartz and quartz is truly important in terms of defining that brittleness.

When you look at this log, you'll start to see that we have multiple zones that could be prospective. I'll just point you to the color scheme on the left-hand side. If it's yellowy or lightish in color, it's likely more quartz-rich. If it's darker in color then it's more of a true shale. So you can start to see there's a couple of intervals right here, a couple of intervals down here, and another interval down to the bottom here. They start to have that quartz content and reservoirs properties that you would be looking for.

And then finally, what's really to the Kreyenhagen and why we've kind of start to hone in on this is that we've been able to establish the proven productive potential of this reservoir by being deliberate within our vertical wells that are available to us. We've been utilizing zonal completions and being tested in different sections of the reservoir to establish how wells may behave from a production standpoint as well as hydrocarbon type.

When you look at this data, we basically observed IPs that range from 10 to 300 barrels of oil per day. And if you were to relate that to other shale plays around the U.S., again there's not many that have established that from vertical wells prior to switching to a horizontal development.

Effectively, as we wrap up, when you look at some of the key factors that drive a successful resource play, we've been able to demonstrate there from the Kreyenhagen that we really have a regionally extensive world-class source rock with significant volumes of high TOC. We have well-defined oil, gas, and condensate fairways. We have the potential for multiple stacked zones that could be individual horizontal well landing zones. And to date, we've been able to establish that the Kreyenhagen is productive utilizing the hard vertical wells that are available to us.

So as we look into the other reservoirs that we've talked about, we see similar reservoir properties, but really we've been deliberate and try to deliver on the projects that we have.

So finally, to wrap-up, hopefully you got a flavor of the exploration potential that exists within California and the upside that exists. It's really a significant opportunity set and a very diverse portfolio that can really truly support the operational groups that we've been doing.

Thank you everybody.

I'll take any questions for another round long.

[John]?

QUESTIONS AND ANSWERS

Unidentified Audience Member

Yes, a couple. For the 125 prospects you have say they're not related or interrelated, could you characterize them by structural stratigraphic? So that's question one.

Darren Williams - *California Resources Corporation - EVP - Exploration*

Sure. So, each one of those prospects would be an individual accumulation that we would be looking at.

When you look around our play types, I would say the majority of them are structural in nature much like many of the fields that we deal with today are structural in nature. But we're starting to kind of identify stratigraphic plays most likely in zones like the Stevens sand, which was the reservoir in the B.V. Nose Discovery.

Unidentified Audience Member

okay. My next, it's the commercial success rate versus geologic success rate.

Darren Williams - *California Resources Corporation - EVP - Exploration*

Yes, Sir.

Unidentified Audience Member

Well, you said you're at 70% geologic. Is that (inaudible)?

Darren Williams - *California Resources Corporation - EVP - Exploration*

Just like the industry we're about half, so I think industry has about the same performance from geologic to commercial.

Unidentified Audience Member

Hi, Darren.

Darren Williams - *California Resources Corporation - EVP - Exploration*

Hi there.

Unidentified Audience Member

So you'll have the stocks good for Marathon...

Darren Williams - *California Resources Corporation - EVP - Exploration*

Right.

Unidentified Audience Member

...obviously (inaudible) the vertical well talking about the Kreyenhagen. What would it take for you to move to compete for budget to move horizontal? And a related question, does CRC have the in-house capability to take this to horizontal development? And if not, would this be, you know, a prospective for a third party if you could elaborate on that? Thanks.

Darren Williams - *California Resources Corporation - EVP - Exploration*

So, three questions there, I think. So, the first one is what does it take to get it from where we are today to an active play?

I think what I would say is we were poised for success. We're on the cusp. We've identified the reservoir that we're focused on. One of the key challenges that we've had is that we have is that we have such a large opportunity set in terms of Lower Monterey, Whepley, and Kreyenhagen, and Moreno. You have to start somewhere. And where we've been is that the Kreyenhagen really has been more advanced in terms of the legacy well available, and our technical understanding, and then effectively our ability to leverage the vertical wells to demonstrate the productive side of things.

You know, I think we've done some good work there. We've established what we're doing. And really I think we're at a point now where you are looking at the horizontal as the next place to go, and that vertical activity has been able to define where you probably high-grade and do that kind of thing.

Second question was...

Unidentified Audience Member

So, the CRC...

Darren Williams - *California Resources Corporation - EVP - Exploration*

Oh, how does it compete?

Unidentified Audience Member

Well, not that the CRC have the capability to do it and without you in potential discussions to bring someone else (inaudible).

Darren Williams - *California Resources Corporation - EVP - Exploration*

So, yes. So I think we address (inaudible) similar yesterday, and what I would say is that clearly I have kind of a technical background and kind of ran a development team and the wherewithal from that.

As you look across Oxy, we had people who work in the back and people who works in the firm you knew come to book there. And then again from an operational standpoint we've had people who work all the way around the world. So I think yes, we have the fundamental capabilities within the organization to get it there, and then again we have the service providers that are active in the basin that are active elsewhere around the U.S., too.

And I think ultimately, this offer up opportunities to third party, I think the simple answer is yes.

Yes, Sir?

Unidentified Audience Member

What is the plan for '16 primarily on an unconventional capital spend given the depth of conventional inventory and the capital constraints in the organization? Is it absent?

Darren Williams - *California Resources Corporation - EVP - Exploration*

I don't think at this point the budget has been set for '16, so nothing is firm at this point in time.

Unidentified Audience Member

But given the depth of the conventional opportunity, I guess, how would you kind of compare capital allocation even though it maybe hasn't been determined today?

Darren Williams - *California Resources Corporation - EVP - Exploration*

Right. I think, at this point, the capital is clearly going to protecting the base and defending our margins. So I think it's really going towards the development opportunities at this point. And really these opportunities come into play just like the large portfolio development opportunities. We're really looking at it from that point on a strategic standpoint.

Again, this offers an opportunity for a third party joint venture down the road in terms of being able to unlock some of that volume.

Unidentified Audience Member

And then given, I guess, a follow-up on the J.V. side for the conventional exploration resource, do you see the potential there to get a full carry through the production? I mean, would that be the strategy given that exploration can open another capital need of which is challenged?

Darren Williams - *California Resources Corporation - EVP - Exploration*

I think what I can relate to is my last role prior to joining the CRC was on the international exploration sense, so I got a feel for what the opportunities are like around the world.

What I would say is that there's a reason people go into remote, in a hospitable security, high security risk countries. And it's because the opportunities are hard to come by. When you pull this portfolio on that worldwide basis, it really starts to stack up.

And what can you get someone to pay for it? Well, that's a question down the road, I would say, but I would just point to when you look at it on a worldwide basis and the opportunities that exist, and this will compete with the best of them in terms of the risk factors and the scale of upside that could exist.

Unidentified Audience Member

Thanks.

Darren Williams - *California Resources Corporation - EVP - Exploration*

One more.

Unidentified Audience Member

Morning. On the 10 to 300 plus rate, is that sort of a typical statistical distribution? Are you seeing something either from an aerial extent or how you work them over that can kind of hone in on the top end of that range?

Darren Williams - *California Resources Corporation - EVP - Exploration*

I would say, yes, we've done stuff that enables us to get towards the high end of the range. And I'll leave it at that.

Okay. I think we're good there. And at this point, I will hand over to Bob Barnes, our EVP of Northern Operations.

PRESENTATION

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

Well, good morning and welcome again to Elk Hills. My name is Bob Barnes, and I'm the EVP for CRC's Northern Operations.

I have over 37 years of industry experience in multiple domestic and international locations, including 14 years of experience here in California. My background is drilling and completions, production operations, and operations management.

Today, this morning I'd like to highlight a few of our world-class reservoirs, CRC's focus on margin, and our ability to drive out costs without doing damage to our production. Later I'll discuss some of our key infrastructure and how it's integrated into our operation, and close with our portfolio diverse opportunities and the project inventory CRC professionals have been able to generate from these properties.

CRC conducts operations over the San Joaquin and Sacramento Basins. We have a large footprint with operations over 4,000 square miles. We operate about 8,000 wells, 7,000 producers, 1,000 injectors. About 80% of our production comes from underneath the beam pumping unit like the one in the picture.

We also operate over 330,000 horsepower of compression, 300 tank batteries, and 44 fluid processing plants, 50 steam generators with a capacity of 218,000 barrels of steam per day, 8,400 miles of gathering lines. We currently run two rigs in our thermal operations. We have 30 well servicing and workover rigs running across the north. And our daily production is about 120,000 barrels a day equivalent, about 66,000 barrels a day of oil.

When the well is not capable of flowing naturally, artificial lift is installed to help the well produce. Artificial lift is designed as per a well's reservoir characteristics such as deliverability or volume, how gassy is it, the temperature, the depth, is our consolidated sand, and then wellbore conditions such as is the well deviated and what is the diameters we are working with.

This cartoon illustrates a variety of artificial lifts that we employ to match the capabilities with the lift to employ of the reservoir in that little schematic of how it works. Well, we used all type of artificial lift given our well bore conditions, the beam pumping unit gives us the greatest flexibility and cost-effectiveness.

The gray tables below is a tally of the wellbores by lift method, and then the lower table is the type of well by regulatory classification.

On our performance metrics, the takeaway from this slide is we have significantly lowered our operating cost while maintaining our production. It is said anybody could cut cost, but the real trick is to do it without hurting your production.

CRC operations team have reduced cost and flattened the climb while improving our well and infrastructure downtime with a much lower capital investment. Below the table is our main cost drivers where we've been able to reduce our cost. We have implemented thoughtful cost reduction, which are sustainable, and we will further explain our cost savings in the following slides.

Our operations personnel are very focused on margin. While we don't set the price of oil, we can influence our OpEx and defend our margins.

The colors in the stacked bar represent our major cost drivers. This chart represents a 28% improvement in the savings. That's about $208 million over this period of time.

Our savings that came from energy to sell supply of electricity at our major builds and less power consumption to our entire operation. This comes from optimization and automation.

We also have realized significant improvement on our wells' downtime, our plant and infrastructure reliability, and the steam costs are also improved due to lower gas prices and improved steam management by our technical teams.

In the prior slides, I have showed you that over 85% of our wells have artificial lift. This scorecard highlights the metrics used to evaluate a well servicing performance.

The first chart downtime, the chart up here shows that we have less wells filling. This is due to our continuing artificial lift optimization and the good work of our failure teams.

The second chart, Waiting on Hoist, indicates the wells that are down that you haven't gotten to yet. In other words, you're waiting on a rig. This metric shows that we are not growing a [bath club] of wells and that the number of rigs we run in are capable of keeping up with the failed wells.

Our third chart, Maintenance Rig Hours, shows that we are working less rig hours by improving our well site supervision and continually reviewing our well servicing processes.

Finally, our Job Efficiency, jobs per hour and jobs per cost continues to improve while our well servicing cost has improved by 21%. And our cycle time has also improved by 21%. Besides spending less money with our contractors, we returned the wells' active production faster. So we're doing more work with less rigs.

This metric also shows the combined run time of our wells, plants, and infrastructure. While we've had good performance in the past, our uptime has continued to improve over the last three quarters that we've been CRC.

Our gas and power plants are running at 99% efficiency. 98.5 is considered world-class.

Our producing wells have a downtime of less than 2%. Less than 4% is considered very good for the type of wells that we operate. In other words, of the nearly 6,000 beam wells we operate, at any given time, only 60 wells are down at any given time.

This slide is a snapshot of our workover activity wells on producing wells. We do workovers on injectors, and it's about one-third of our activity. But one of the things that's hard about injection wells, they're more like service wells so you don't have an I.P. to immediately compare your results, so that's why they're not on this slide.

This activity set is artificial lift optimizations as we have discussed earlier and jobs of opening new pay into the wellbore. The graph illustrates our focus on oil and the associated gas that comes with the oil.

Our workover activity clearly exceeds CRC's threshold of 1.3 VCI. That's had a $50 price. We are continually adding workover candidates to our inventory and prioritize our projects for implementation as capital becomes available for investment.

This chart represents the major fields across CRC's Northern Operations. The blue bars is the production, and immediately above the blue bars is the percentage of oil. The red curve is our cash margin generated by these fields. Please note that the primary Y axis is a log scale.

The takeaway from these slides are -- our portfolio's top fields all have favorable cash margins in a slow price.

This year's capital activity has been based at the steamfloods of Lost Hills and Kern Front where we have our high margins. And third, Elk Hills, our biggest producing field with the slow OpEx, continues to generate good cash margin in today's prices.

Elk Hills is CRC's flagship and responsible for nearly 40% of CRC's production. It also leads a charge on our OpEx reduction. Elk Hills has exported much of the automation and other process innovation across CRC and our former parent Oxy. You'll see some of Elk Hills automation and control capabilities later this morning.

Elk Hills is a combination of many operations that other operators consider midstream such as gas processing and power generation. A typical day's production at Elk Hills area is 25,600 barrels of oil, 16,400 NGL, over 140 million feet of gas, and we make about 500,000 barrels a day of water.

One thing to note that the gas produced at Elk Hills, which is the largest gas-producing field in the state is associated gas. Again, that's a gas that's produced with the oil.

The north major facilities are integrated into our daily operations. When gas leaves Elk Hills (inaudible) tip quality and requires no other processing.

Gas is gathered through three stages of compression, from pressures near vacuum at the wellhead to 450 pounds to enter the gas plants. We use over 300,000 horsepower compression to do this. That's about 1 billion feet a day for 300 million feet of inlet to the plants.

Elk Hills Power generates 550 megawatts of power. That's enough power to power 500,000 homes. It is a qualified facility, which allows CRC sell supply, and we may use off-spec gas in our operation. That saves us from having to reprocess or reinject the gas that's off-spec.

With Elk Hills Power we also are isolated from loss of power events on the grid. Our reliability is much better than that of the grid. With this integrated infrastructure, if we use traditional third party suppliers of these services, our midstream costs would be $200 million a year.

CGP1 was commissioned in the summer of 2012. The cryogenic process is has improved our NGL recoveries with over 3,000 barrels of oil a day. Our cryogenic plant, which ensures we meet BTUs and Dew Point's sell specifications of our gas purchasers is running at a minus 110 degrees F. In comparison, our low temperature separation units are running between minus 33 and minus 38, so you can see the effect that it has on the recoveries.

Elk Hills has stability to move north and south as well as to smaller cogen operators throughout the San Joaquin Basin. This again, as planned, has reliability of 99% uptime including this morning, so it's again a world-class plant.

Another thing on our gas stream has at least it's [versely] propane-free. 99.9% of the propane is removed from this gas, so it's a very, very efficient plant.

The cross-section of the basin highlights the wide seismic dataset the CRC holds, which is larger than the dataset than any other operator in California. The dataset contains recent shoots like the one we just finished in March, many vintage shoots and many subsets that have been reprocessed.

The cross-section illustrates on the major geological markers across the San Joaquin Basin. Again, this demonstrates our multiple stacked reservoirs across the basin.

The San Andreas Fault is located on the west here. And here we are at Elk Hills. You can see it come across all the way to our steamfloods in the east, Kern Front, and Mount Poso. If you are to follow, they're actually going across the basin on the western side of Elk Hills, it's called the Western SOZ. It's about 5,000-foot deep. On the eastern part of Elk Hills, it's about 3,000-foot deep. And you get out to our steamfloods, it's approximately 2,000-foot deep. That gives you a scale of what that lines were doing.

This slide highlights the major stacked reservoirs of Elk Hills. Across the top of the cartoon is the formations and the date that the reservoir was discovered. The column on the left indicates the number of penetrations through the respective formations.

The first four well bores on the left are the major producing horizons at Elk Hills. The five to the right are the deep well tests that had been conducted at Elk Hills intermediate area. Although these six wells were not commercially successful, they are producing -- most are producing from traditional reservoirs in shallow or depths.

Elk Hills is over 100 years young and still enjoys exploration success. We produce the stacked reservoirs with primary, unconventional and waterflood dries. There are four reservoir teams and an exploration team that generate and implement a very diverse inventory or projects that maximize value of Elk Hills. Our improved base surveillance, reliability, and well uptime has helped flattened our base decline at Elk Hills.

The first graph shows Elk Hills Field water/oil ratio. You can see that the curve is beginning to break over and will flatten. This is due to the decreasing water production from our shale wells and that we haven't drilled any shale wells in 2015.

The second chart displays the OpEx reductions on a per well basis. I have talked about the improvements and our variable costs such as down well maintenance, reliability, job consolidation, and power optimization. With less than one-third of our OpEx being fixed cost, we believe that with thoughtful review, we can further reduce our OpEx by continuing to improve our operating efficiency.

The third graph shows Elk Hills OpEx plotted on a BOE basis. Please note that the decreasing OpEx was achieved with an increasing well count and with lower production.

This is a map of the Elk Hills unit and the adjacent properties to border it. These are also operated by Elk Hills personnel. Each square is one square mile. For your reference, we're here at 2B. That's right in there.

You can see the major producing structures on the map. You have the 31S, the 29R, Northwest Stevens, and the Gunslinger. This slide also shows early displays or stacked reservoirs of Elk Hills. For example, the purple line outlines the world-class SOZ reservoir. This is a reservoir that contains [3 and 4RC] rock. It's overlaying the Stevens and shale reservoirs, which are deeper.

Listed in the textboxes that surround the borders of the unit are the producing intervals for the respective major reservoirs.

So this slide represents CRC's value creation process. As the project goes from an idea and begins to mature, we work it until we have a project that is capable of meeting or exceeding CRC's hurdle rate. This is sample of projects in the Elk Hills area at $50 spend. These projects are grouped by drive mechanisms. The left table represents a VCI of one, and the right table is projects that are meeting the 1.3 VCI. We like to describe this is a chart as work in progress of our value creation.

We have a few slides with other projects across our Northern Operations we like to share with you today.

Jerry Foster talked to you yesterday about Mount Poso. Prior operators had stopped injecting steam in 1980, and the ground remains hot today.

This map displays how we are expanding the Vedder waterflood, north to south, and moving west stepping down the structure. We have drilled six wells earlier in the year and you can see the results. We drilled four vertical wells, two horizontals, and there's our economics there, 400 barrels a day for a $3 million investment and our results.

The curves the textbox brackets the possible outcomes from an accelerated cash to a low decline with little or no investment.

On the Pleito Ranch, you drove by this field yesterday on your way up here. This is you got off the Grapevine. Pleito Ranch was in the mountains west of I-5, so on your left-hand side.

The production table on this slide show why we are excited about Pleito Ranch, another example of CRC's professionals and what they have been able to do from the prior operators. Our geoscientists have added additional opportunities to their work and knowledge, interpretation analysis of basin geology, and petrophysical data. Our drilling teams have been successful in driving down drilling cost, and we have opportunities to exploit as oil prices improve.

The picture of this outcrop demonstrates the geology at the Pleito Ranch area. It's nice to have a picture to see what you're doing 15,000-foot below.

I'll give you a quick example. Some of our drilling efficiencies in here, our well started out costing $6.5 million in Pleito. The guys reduced it to $4 million and the last two that we've drilled out there came in at $3.1 million. This is due to optimization casing setting depths that we have a range of different pressures in the intermediate hole. The guys really were aggressive with that. We've reduced our logging. And it was just paying attention to details. It kind of shows the effectiveness of when you have your reservoir teams and your drilling teams teamed up as one.

Buena Vista waterflood, when you come out of the [CCF] this morning to get on the bus, you'll see Buena Vista flood in the distance there. Buena Vista is another example of a field that we were able to improve after taking over operations.

The previous operator was drilling small five-acre pattern right up in here. This is a poorly managed waterflood. (Inaudible) using it as a place to put his produced water.

Our waterflood teams redevelop this in a 20-acre pattern. You can see on the different categories here, green is the area waiting on response. Blue is developed. Yellow is our PUDs. Orange is possible, and then the large gray contingent area.

Many of the artificial lift upgrades that we mentioned before were performed here at Buena Vista due to the successful response of the waterflood.

Similar to Elk Hills, we have a shale program right underneath the very same field where the water has been officially utilized for the waterflood, so it's kind of a symbiotic relationship there.

So I hope I was able to show you some of the great reservoirs we had to work with and then how we flattened our decline by increased surveillance into our reliability.

Our cost reductions are sustainable, and we will continue to be focused on our margins to optimization without damaging our production. This is our culture.

We have an expensive infrastructure that's integrated into our operations with world-class reliability.

We have inventory of today's prices and additional inventory as prices improve. We have demonstrated our ability to execute effectively.

CRC has a portfolio of diverse assets operated by driven professionals in a safe and environmental sound manner.

So before I turn it over to Vic Ziegler for an overview of our thermal operations, I'm glad to take any questions.

QUESTIONS AND ANSWERS

Roger Read - *Wells Fargo - Analyst*

Thanks. Is it on? Yes. Roger Read, Wells Fargo.

Getting back to the 15% decline rate you talked about, is that after everything you do that's before you do something, what is it that you do to minimize at 15% account closer to 10% or so?

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

Is that on Elk Hills or you're talking about this slide?

Roger Read - *Wells Fargo - Analyst*

Yes, yes, specific to Elk Hills, I believe.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

okay. That is where we're at currently. That's with all our downtime. As Todd mentioned before, you have the capability between 10 and 15, and right in there is where I'm moving, so we hedge a little bit there on what we call our actual decline there, but that's in the area we're at. It's current.

Yes, Sir?

Unidentified Audience Member

What would be the expectation of where that could be moved based on what you're doing today? I mean, an internal goal, best practices kind of number.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

I'd say that we have a couple of points we might be able to get off that, but again it's what the surveillance, the capital investment, the workovers, optimization of the different wells, the response of the waterfloods, these all come into play. Okay.

Unidentified Audience Member

And then my follow-up, recognizing some of those may be proprietary. You talked about the waterfloods and the steamfloods prior operators didn't do particularly or didn't have particular success with it, how much of it for you is significant computer programs, and so forth, just a testing and retesting of information that comes from other parts of the world where these projects go on, just how broad, how deep is that?

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

okay. One of the things on the Mount Poso, we're waterflooding a different reservoir that what they had steamflooding. So that was just a benefit of the being hot.

And Vic and Jeff, they know so much more about steamfloods than I do I'm going to try talk to you about. You'll see that here in just a minute.

We are probably the most automated field. I know we're the most automated field to CRC and to Oxy, and I would say inside the United States. We're like a 75-square mile offshore platform. We exploit our automation, our databases such as [Pie].

And it's one thing they had the data and the information is another thing to do something with it. And I think that's -- I put that on our -- the technical capabilities and the desire of our people workforce.

Unidentified Audience Member

I think your slide 38, I think the books may be a little different than the deck. But I just want to show the VCI 1 for the inventory and then the VCI 1.3 (inaudible). Thank you. Yes.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

Sorry, that one?

Unidentified Audience Member

Yes, that's the one. So what are the things that you can do to move the left side to the right side? What are the kind of things you're doing? It gives a (inaudible) report or not.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

Yes, Sir.

Unidentified Audience Member

And if you could also give us an idea that's a '16 to '20 time line, what does inventory looking for [whole of life].

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

okay. So on the life of field, we're breaking it down into the near-term, I mean, yes, we have a lot of contingent projects in the whole life of the field. I'd like to talk more about what we're doing to move it from 1 to 1.3.

One of the things we do is we all kind of break back into our disciplines. The (inaudible) is am I being conservative as Todd talked to before, what's our degree of certainty, how accurate are my forecasts? Are we overbuilding our facilities? Because we have an unrealistic range or am I underbuilding my facilities because I want to be conservative.

Our drilling guys go back, and we look at -- on case (inaudible), we challenge a number of case and strengths we need. On facilities, if it's a facilities-driven project, what is the life of the project? Are we building something that's indestructible? Are we going to build something for the life of the project? That's a consideration we need to look at.

One of the things we've done, we've been very instrumental and running a lot of composite pipe. Not only does that save you on the installation, but it saves you on your mechanical integrity and your OpEx down the road.

So, basically everybody goes back home and looks at their section, and make sure we got the best thing forward. We put it back together and make sure we're not doing anything that's hurting each other, and that we got the project in mind instead of our discipline in mind.

Scott?

Scott Espenshade - *California Resources Corporation - VP - IR*

Yes, thanks, Bob. One of the numbers you mentioned was $200 million if your midstream services would have been provided by a third party. I guess, I was wondering to begin with if you could just be a little bit more specific about which midstream services you're including in that number. Is that gathering, compression, processing, power, is that everything or is that only a subset? And then secondly, if it will be possible to break down that $200 million a little bit more on a granular level between the different midstream services.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

I feel more comfortable telling you what it includes and then the breakdown. Well, we can get to you. Scott can get to you later.

But it includes our power cost. It includes our gas processing and our transmission cost as well as our gathering. So it's all in there. And again these are many services that very rarely do you see a gas plant located in the middle of a field usually 70, 80 miles down the road where you have tremendous line pack that the plant dumps -- the field never knows it, right? Ours is all right here. It's like working on an offshore platform. I mean, we have to be quick with our response because the chain reactions go fast.

Todd Stevens - *California Resources Corporation - President, CEO*

One thing you might want to point out, Bob, is that the slide, this doesn't include CO_2 and...

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

Oh, yes.

Todd Stevens - *California Resources Corporation - President, CEO*

...this doesn't include ASP, so it's not all inclusive. This is what we think realistically over the next few years.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

That's a great point, Todd, and I meant to bring that up. Our major projects, the [main body B], the [Centennial C] on the tour today, guys, that's the best CO2 candidate we have.

When we did our peer reviews with our former parent who has great CO2 capabilities, they were said that the Main Body B project will be the best project we had if we can move it to the Permian, so we're working on the source of CO2. We're looking at all of this.

The Main Body B, I mean, sorry, the Eastern SOZ has like four or five different projects, everything from potential light all steamflood.

ASP polymer, there's a [crest] of waterflood, there's a gathering project. We have tons of projects out there. And it's just we only got one slide though.

Yes, Sir?

Unidentified Audience Member

Two questions, one on the waterfloods, what's your typical response time? And then the second question, do you have a lot of Rotoflex pumps rather than just being pumps out there? How much more efficient are they since they're longer stroke?

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

On the waterflood, I mean, it's all about the geology and the fill-up. So on our typical waterfloods, Brian, you can help me out there a little bit?

Brian Owens - *California Resources Corporation - VP - Operations*

Yes, there's B.V. would be a good one.

Unidentified Audience Member

Yes.

Brian Owens - *California Resources Corporation - VP - Operations*

So, what you saw earlier for the example for the B.V. waterflood is largely with (inaudible) today. Those that go forward will bring that waterflood response or switch into a lot of ESPs.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

On the -- I'm sorry, I forgot the second part of the question.

Unidentified Audience Member

You have Rotoflex (inaudible).

THOMSON REUTERS

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

Oh, yes. So, the Rotoflex gives you a very long slow stroke. Actually, its capacities rival a small ESP, but you have the advantage of the rods that the crews are used to handling. An ESP does not like heat, gas, or sand, so it's a much more cost-effective method for us.

One of the things we do, the elliptical rod where there's no coupling, it's like a (inaudible) roll like a coil tubing. We have over 1,000 applications of that at Elk Hills and also Ventura has some applications of this. It's really great. You put the elliptical rods with the polyline tubing, and you have a pretty reliable operation there. And it's easy to service and cost-effective.

Yes, Sir?

Unidentified Audience Member

On the Buena Vista slide, can you please walk through the capital spending assumptions that will be necessary to increase the production? Also, what R.F. means?

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

okay.

Unidentified Audience Member

And then what the lease operating expense per barrel would be on that sort of project?

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

okay. So, the R.F. is the recovery factor. Our tradition on the waterfloods, it'd probably be in the neighborhood of -- I'm going to back it up between $15 and $20 a barrel.

On the capital that's invested, we do have infrastructure there already, so this is a step-out. Of course, as you go to exploit the far tips of the contingent, if we're successful in that, that will be additional trunklines, but your pumps and those kind of things are usually already in place, so you're having your injection capacity mainly just extending your infrastructure.

Of course, if you really get successful in moving a lot of water, you'll have to put substations in. I'd say there'd be normally of 20% to 25% of the project. One of the things we strive for is the 15% target on our facilities, but on a major project like the waterflood or a gas plant or something like that is going to be much higher. I'd say within 25% of the budget will go. Our main cost will be that well conversions and the drilling of the wells that where the reservoir engineers want them.

Sir?

Unidentified Audience Member

For these high rate of return workovers, do those workovers add reserves or do they primarily pull the production forward of the current developed reserves.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

That's our definition of capital workovers. We have to add reserves.

Unidentified Audience Member

okay.

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

So that's -- yes, Sir, the team, they do that reserves.

Yes, Sir? There comes one right here.

Unidentified Audience Member

How long does it take your typical well at Elk Hills to reach mid-90's water cut? And do you need to invest in water (inaudible) facilities for these fields, too?

Bob Barnes - *California Resources Corporation - EVP - Northern Operations*

On the water cut of the 90's, I'd say it's years, I mean, it's been to where you're at in the reservoir. Frank and the Long Beach guys showed you yesterday, they're in the 98% cut and making money. So our infrastructure, since we're all in one area, we deal with the water in the [China] infrastructure, and so we're also feeding waterfloods off this, so the water disposal capital is minimal for us.

We have capacity from priority investments is what I'm trying to say. So, to add additional wells right now, we don't have to mess with it too much. Occasionally, on extra disposal well or a pump goes bad, but nothing major, but it's years before we get to that cut.

Okay. I think we're ready for Vic there. Thank you very much.

PRESENTATION

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Well, good morning everybody. My name is Vic Ziegler. And like Bob, I've got 37 years of experience in the industry. I'm older than Bob, but I'm a slow-learner, and so I had to stay in school longer.

I am a petroleum engineer. I've had the good fortune to work on thermal projects around the world, mainly in California, Indonesia, Oman, Bahrain, Canada, and Colombia. It's a worldwide EOR process. And I'm going to do a tag team here with Jeff Hatlen, our chief thermal reservoir engineer. I'm going to give an overview of thermal EOR, get you grounded in the technology. And then Jeff is going to show you how the process is applied very successfully in our fields.

I thought this supposed to go forward. Oh, here we go. Okay.

What I'm going to do is kind of give you this update on thermal EOR as it have applied throughout the world. We'll talk a little bit about the different processes, get those defined, show you a little of the historical, very brief historical perspective, how steamflooding fits into the current economic climate, and then discuss some of the key improvements that have occurred as a result of price changes, and what our future opportunities are.

So, a cut to the chase, kind of the key things on thermal, steam injection is the most successful EOR process in the world, and one of the reasons why that happens is because of the very high recovery factors that we can get up to 70% of the oil-in-place.

We always respond to changes in economics, and this has driven application of new technologies to steamflooding and has made steamflooding very successful in difficult environments. Thermal operators focus on what the oil to gas price ratio is. That's a critical parameter, and then how to manage both water and heat within the reservoir.

Looking forward, future opportunities, we think that there is a big upside in fractured reservoirs. You've seen some of the diatomite up here, that's a very significant potential development for us. And we have a significant inventory of steamflood projects, so we see the size of the resource and the length of the project lives boding very well for thermal operations in California.

Okay. Just a review of the thermal processes, there's really three here. Really the first one is a cyclic steam stimulation. It's applied to a production well. So three-step process starts by injecting steam into our producing well on the left panel there. Usually we inject for a few days to a few weeks. Then we shut that well in and let the heat dissipate. And while it does that, it reduces the viscosity of the oil in the reservoir.

Then as the heat is dissipated and the pressure is reduced, then we turn the well back around and produce it. We can produce it anywhere from a few months to a year typically. And this process is used as a precursor for steamflooding and as a supplement. It helps us even up the steam fronts in our reservoirs.

This is the cartoon here of the steamflood process where we're generating steam on the surface and the steam generator. We'll inject it continuously into usually a centrally located injection well. And then this will heat the reservoir. It's the most effective method for rapidly heating the reservoir. And because steam is less dense than the reservoir fluids -- the oil and the water -- it will typically override the oil column and take an override position.

Another process that's been tried is called in situ combustion. You may know it as fireflooding. Here, air is compressed and injected into an injection well. And the oxygen in the air reacts with the oil and generates very high temperatures up to 1,000 degrees. It's a very unstable process. It's hard to control the fronts. It has poor sweep of the reservoir, and that usually leads to very poor recovery.

What I'm going to show next here is kind of our risk reward diagram of the reward here is the reserves we get. That's the Y axis on this plot and then investment on the X axis. Okay? And kind of the apex of the triangle here is steamflood. And that really is the most effective method for thermal EOR.

This shows the production over the last 30 years. And the bars here, the orange bars are steam injection. The red is fireflooding. And then the black curve here is oil price. You can see in the early 80's when oil price was high, this led to a ramp-up in projects and steamflood production.

Even when after the price collapse of 1986, production stayed fairly high, about 450,000 barrels a day. And a lot of this has to do as how a pattern would respond during steam injection.

Then in the 2000's, when oil price started to rise, it helped sustain the production of around 300,000 barrel a day level.

Okay. This is the picture of a typical steamflood. Actually, it's our current front field, and the key thing I want you to get out of this picture is the very close well spacing, how close the wells are together. Typically, around 300 to 400 feet would be typical. And the reason why this occurs is because underneath this particular reservoir, they're up to 12 sands that are productive, so we've got a large inventory of layers here to process. The other thing is that heat transports slower than water.

Okay. This is kind of a time line of the process of thermal EOR. There's a long history here. The initial experiments, field experiments were done in the 30's.

Large-scale pilots began in the 50's and 60's. And what was learned during those pilots was that steam is much better than air. So, large projects were begun to be implemented in the mid-70's. The world's largest steamflood, Duri steamflood in Indonesia began in '75. Again, very large projects, field-wide projects were begun in California in the mid-70's in Venezuela.

Okay. 1986 happened. Oil prices crashed. That caused us to take a look at how we did steamflooding and led to some enhancements in the technology, things like the application of horizontal wells, reservoir heat management that came to the forefront.

In about the early 2000's, oil prices started to rise again, and this led to a worldwide expansion in steamflood technology, particularly in the Middle East.

Okay, like the late Yogi Bear has said, it's deja vu all over again. Prices have collapsed, and so we need to live with this at problem (inaudible) [Pie] what we learned in the past.

Okay. This is a production for Kern County on the left there. 95% of the steamfloods in the United States are done in this county where you're at. And again it shows the production beginning in the late 70's. As oil price was going up, production started to ramp up.

Then after 1986, we're at a plateau level. Even though the number of projects is declining, we're staying flat. That's just kind of the nature of steamflooding in a pattern. And then we do get to a decline, but it's a very shallow decline. That green area there, that's a 9% decline. Okay. So you could compress that vertical stale, and that would be the history, the production history of a typical steamflood pattern.

Okay. With the '86 event, similar to what's happening now, there are some key improvements, reservoir heat management. That's the number one. We'll talk a little bit more about this, but typically for every MCF of gas that we burn, we generate 2-1/2 barrels of steam. So, for a $3 gas price, that means the fuel cost of a barrel of steam is about $20. It's about an order of magnitude higher than water cost and a waterflood. Okay.

So, typically, fuel costs represent about 50% of our operating expense in the steam flood.

Other big thing is we have multiple reservoir stacked upon each other. And we apply multi-reservoir developments here, and we can utilize that to accelerate recovery, increase the life of the project, and utilize some concepts called hotplate heating. You'll see this one Jeff talks a little bit more, but this will help us minimize the use of steam.

Other key development is the use of horizontal wells. This began about in the mid 90's to late 90's when we started getting equipment that could improve how wells were placed.

Now, that picture on the wall over there shows horizontal wells. And by doing horizontal drilling, you're increasing the contact area in the reservoir. So what that does is it improves the productivity by a factor of two to 10 times, but doesn't toss that much more to drill a horizontal well as compared to a vertical, typically, 1.5 to 2 times only.

Other things, the acronym there SAGD, Steam-Assisted Gravity Drainage, very effective method for tar sands, we have some of that.

Other key things and you'll see a picture or what we call slimhole injectors. They're about 50% to 75% of the cost of a normal producing well and they're very effective. The other thing is the rise of desktop computing. I think you can with your little laptop design a steamflood that would have taken a supercomputer about 20 years ago.

Okay. I want to talk a little bit more about reservoir heat management. The cartoon on the left shows what happens when we inject steam into a reservoir. Again because it's less dense, it tends to ride across the top of the formation. It's very expensive so we want to make the most use of that we can. Okay, steam will transfer heat to the oil layer beneath the steam zone and then also will have some heat losses to the shales here.

This is not entirely misused heat because particularly, they're be multiple sands here and we get what's called a hotplate heating. That will help drain those sands.

The typical steam rate that we would apply is shown here. Initially, we'll want to inject a higher rate to get the area covered with steam so it moves across here. We'd like it to condense right at that point if we could.

And once we have that area heated, we can cut it back by doing some simple engineering heat balance calculations. And then what that does is it frees up steam from our plants to develop additional projects either vertical expansions or aerial expansions.

So -- and normally, what we are seeing, and Jeff will show you is we can do these great reductions without affecting the production trend.

Okay, this is kind of an example of how we do steamflooding in a multi-reservoir field. We start on the left here. This is a typical pattern geometry that we use. It's called an inverted 9-spot, has eight producers surrounded by an injection point.

In this particular cartoon, we have two injectors and these are slimhole producers. Essentially what they are, is tubing cemented in a borehole. There is no casing. It's just tubing. Okay.

The key thing here is, this is our reservoir cross-section, our well logs. And each one of these injectors have been injecting into this zone, the other into this zone, so this one is being done sequentially. We can also do it in a -- or excuse me, this is simultaneously. We could also do it sequentially where we would start at the bottom and work our way up.

All these green and orange intervals here on the well logs indicate potential vertical expansion zones. So normally, we complete all of our producers in every sand that has oil in it, and then all -- so we can use these producers for multiple steamfloods, and this really makes very effective use of our capital. All we have to do is recomplete our injectors into new zones when we want to start a new steamflood.

This is kind of the life history or production history of a typical steamflood pattern or pilot area. And this was from 9-pattern pilot in Kern Front. In the late '70s, cyclic steaming was started. The green curve here is the monthly oil production. See the response we get with cyclic steam.

And then we began the steamflood in '91 here and we get a ramp-up, a flat plateau and then a start of the decline. We really analyzed this particular project very effectively with well logs and cores and found that the recovery is up to 70% in the zone that we were attacking here.

Then as more steam became available, we could do vertical expansion floods and that's what you're seeing here. So this is the kind of normal progression you'll see in a steamflood project where we have multiple reservoirs.

On the worldwide basis, this shows the production by country. Overall, 1.2 million barrels are produced by steam injection in the world. We're number 3 and we're very close to number 2 actually. And Venezuela would be number 1 then Canada then us and then Indonesia.

Now, a lot of the projects that are developed in Venezuela, Canada and Indonesia were really done by companies that learn their trade, their craft, if you will, in California and they exported the technology to those countries. So California is really kind of the training ground for thermal EOR.

Key thing here is oil price to gas price ratio. What's shown here is the ratio of Brent to Henry Hub and the spread line is the value of five. Now, you can see in over this time period, we were doing very successful steamfloods as long as the oil price to gas price is over to five.

Currently, because of the recent price trends, we're still in a very effective region of oil price, gas price ratio. It's about 15 right now. So we're in a really target-rich environment here in terms of price, and that means we're able to get very good margins in our steamfloods. A lot of this is because we're dealing with shallow reservoirs, the well costs are very small, typically less than $0.5 million a well.

We do use water, we burn fuel gas, so we have regulatory things that we need to pay very close attention to. We're fortunate in a lot of our steamfloods, the reservoirs that we're flooding contained very, very low salinity water, water that's very good for crops.

And we provide surplus water to agriculture in the San Joaquin Valley. And it says there, we provide more treated reclaimed water from our thermal operations in the amount of freshwater that we purchase.

Now, as you heard last night from Steve Bohlen, we need to take very careful care on our underground injection control. And we do this. You know, we operate a material balance. We want to make sure that what we inject and what we produce are in sync.

Now, the state will seek to replace water disposal with recycling, and we're there, okay? Now, we burn fuel, so this will cost some emissions and we offset those emissions with greenhouse gas allowances just as a small additional cost to our projects. This does not stop us from implementing any of our projects.

Innovations, there are some new tools and some old technology. One of the key ones here is using solar parabolic troughs to capture the energy from the sun and they use that to either preheat water to feed into a steam generator thereby reducing our fuel cost or actually creating steam directly.

The key innovation here was placing these parabolic troughs in essentially a greenhouse. So they're protected by from the climate.

Another technique is seismic, because steam is very low density fluid, you can see it on seismic. The problem in the past has been they took a long time to process the seismic in order to see the change.

What's happened here, the innovation here is having varied sources in sands, so you can get a daily reading of the movement of the steam zone, which is what's shown here. Here is in June and here is the picture in August with the yellow being the steam.

Okay. Some new things, you know, a lot of our heavy oil sands are developed, partially or fully developed. And when we're dealing with steamfloods, this is what we normally think of. Essentially, a bunch of unconsolidated sand held together by heavy oil.

So where a number of targets here are decreasing, the new reservoir type is maybe amenable to thermal recovery such as fractured carbonates. This is primarily in the Middle East. They're doing a number of large scale projects there and seeing success.

Now, in California, we have a huge resource diatomite and shale. And so those are the things that would be very interesting and what we're looking at now.

Okay, with new reservoirs come new recovery mechanisms. Overall when we inject heat, what we're trying to do is reduce the viscosity of the oil. That's what's shown on the left here.

Now, in fractured reservoirs, typically, the matrix permeabilities are very low, so when we inject heat into the fractures, we get some additional mechanism occurring here such as capillary imbibition, the water will go into the matrix and oil will come out into the fracture and be produced.

Also, as we heat the matrix, thermal expansion will occur. So those mechanisms are accounted for in this model that we have for estimating how injection into a fracture of reservoir would occur.

Okay, I just want to sum it up here on the key highlights from this introductory portion of the talk before I turn it over to Jeff.

Again, steam injection is a very successful EOR process, something we understand. It gives is very good recovereds. It's a labor-intensive project. You've got to work reservoirs. The reservoir heat management and multi-zone developments, all of those make steamflooding very attractive even in mature areas like the San Joaquin.

We understand the economic drivers here very well. This is where our reservoir heat management really comes into play. We think the future is very bright here particularly applying it into new reservoir types which we have a very large resource base to address.

So I'm going to turn it over now to Jeff Hatlen who will talk about steamflood -- our steamflood operations.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Thanks, Vic. Good morning. I'm Jeff Hatlen. It's a pleasure to be with you this morning. I hope to share with you some of my enthusiasm for thermal recovery and the kind of activities we have at CRC.

I've been active in the industry for 38 years, probably 75% of that in heavy oil thermal. Like Vic, I've designed, built, operated, troubleshooted steamflood all over the world. I've been through progression of companies, [GETI], Texaco, Chevron, Oxy and CRC, so I've had the chance to see how companies apply this technology in -- outside of the CRC. So I'd like to share with you a little bit about what I've learned.

I hope to leave you with the impression that steamfloods have a lot of upfront investment, they strong margins but they offer stable, long-lived declines when operated efficiently, it's strong backside cash flow that creates real value.

So the opportunity here is to make these things as financially impactful as possible. The old operators back in the day, as Vic talked about, did a lot of the heavy-lifting and learning how to do these projects effectively. What I hope to show you is how we're applying them and that we are doing a great job of operating our steamfloods.

So to do that, let's talk about a brief introduction to steamflooding. I'd like to leave you with the impression that steamfloods have a lifecycle. They have an immature and a mature phase.

In the immature phase in the graphic is during startups, steam injection is the high rate, the red trace. We, in that process, build out our steam from our injectors out to our producing wells in these patterns that Vic talked about.

We eventually arrived as the steam to the producing wells from the injection wells. This is a really happy time in steamflooding in a sense that you're really getting after the injection, production is ramping up, it's coming into a peak, it's very exciting as an engineer and geologist responsible for projects.

The interesting thing is that most of the life of the steamflood actually occurs in what we call the mature state. This is where the steam is overlying the oil as Vic described, and through thermal conduction, heating that oil, reducing its viscosity and allowing it to drain into the producing wells, surround the heat injector.

This oil drainage process is incredibly effective at recovering oil. It just happens at Mother Nature's phase given the design that we have for our steamfloods, and I'll show you more about that.

The beauty of the mature phase though is that's where real heat efficiencies can become enabled and get captured, that releases strong cash flow. So the natures of steamfloods are that they have a lot of levers in them to optimize and they deliver strong cash flows after the initial investment.

I'd also leave you with the impression that steamfloods follow a path. Generally, we drill our producing wells and we operate them with pumps, so we're making primary production. It's generally very low recoveries in our heavy oil settings just on primary, maybe 5%, 10% or, in really lucky, 15% recoveries ultimate.

We eventually recognize the opportunity to heat the oil and improve production performance and recovery by cyclically steaming, as Vic talked about. The real thermodynamic bounty comes with continuous steam injection, and that's the path that we ultimately get to.

Now, you can jump into the thermal heavy oil setting anywhere in this path. You can go and drill your wells and injectors, and immediately startup the steam injection. But once underway, it's best to operate the steamflood continuously, turning them on and off, you know, altering their operating parameters are damaging to recovery. So that's our introduction to steamflooding.

What are we doing with the steam? Where are we going with it? What do we target? So you heard our reservoirs are like a layer cake, if you will, of sandstone and clay. The sandstone, of course, harbors the oil anywhere from 30% to 50% to 60% oil saturation is what we lust for.

Each sandstone layer is important. In the past, we might try and target multiple sands but our technologies for controlling the steam were not up to the [top]. I hope to show you examples of what the previous operators, how they operated and what that looks like to us today. The question was asked, you know, what -- how do previous operators underperform to today's standards. I hope to show you a picture of what that looks like in one of our steamfloods.

So to achieve the highest cash margins, we really need to control each and every layer. Fortunately, we have the technologies for doing that today and we have the capacity to survey what is happening in those layers to know exactly what to do, exactly how to set the burners for the steamfloods.

So understanding how the steam moves through the layers is what drives success. We have to be able to see inside the reservoir. We developed a common conceptual model of this lifecycle of a steamflood. We developed that perspective, that model through direct observation.

We have wells drilled, submitted in [case], filled with water that we do nothing more than run logs periodically through to monitor where the steam is going and how the oil is draining, and that's the key to our success.

We also (inaudible) surface data, our production monitoring, injection monitoring, and finally, our operators who are out there with their eyes and ears everyday monitoring performance, evaluating wells and keeping them running in top conditions.

So if we were to dig in to a steamflood, a little bit like Vic was showing, I'd like to do a look into one of those, a slice of the cake, and we'll look at one layer, the upper left graphic is a layer sandstone filled with green oil and we're injecting red hot steam in the injector and we have surrounding producing wells.

The graphic to the right at the top of the slide shows the ramp-up of oil production and it shows the high injection rate shown in the red trace indicating the startup of the project.

Notice how in the simple graphic on the left the hot red steam is moving along the top of the layer of sand as it moves further out from the injector, as we continue and inject at high rates.

Later, we experience steam breakthrough, that's the middle set of graphic. We see that the steam has progressed from the injection well all the way to the producing wells. It's completely overlaying the underlying oil now. And the production plot on the right shows that we have peaked and we're actually beginning to decline oil production.

Finally, the lower graphic show the state of maturity. This is where the steam is completely overlaying the oil. The underlying cold oil is being dramatically heated by that hot steam. Its viscosity is dramatically dropping from something like molasses or honey down to merely water.

That mobility allows it to be drained off in our producing wells effectively much like a tank filled with oil with a valve at the bottom. When that valve is open, that tank is draining. The rate of production out of that valve is high because the heads available within the tank is great.

As that tank drains, the head diminishes, and the flow out of the valve diminishes. That's the decline rate you see in green. That's an exponential decline and our steamfloods can range from 10% to 15% decline rate typically given the nature of the number of the wells we provide and the spacing of the wells and the size of the patterns.

It's at this stage when we're blanketed with steam that we no longer need to apply full rates. We can dial back the steam that that just needed to keep the steam just hot, the underlying oil melting and draining into our producing wells.

So let's take a look from the air. Let's look down in plant view at one of our steamfloods now. Our unit of operation of steamflood is the pattern. In my case, I'm showing an inverted 5-spot, so I have four wells surrounding an injector. Vic showed nine wells surrounding an injector.

We take that -- we take that -- I'm going to shut up the speaker here-- we take that pattern and we group them into a common start-date and a common target layer within the reservoir. And we take those pattern groups and expand them over time, the -- this -- representing an aerial expansion of our steamflood process that we apply in Kern Front, Lost Hills and our other assets, okay?

If I were to bore into one of those -- if I were to bore into one of those patterns and look at the steam from the top, you see the movement of the steam aerially building up from the injector over the producing wells and the attendant behavior of ramp-up, peak and decline in oil production and the trajectory of the steam required to develop that.

So that's the cartoon, that's the theory, let's start taking a look inside of our reservoirs and see what we see. So here's a log strip of the Kern Front field. Where you see green, that's the oil-bearing sand.

When the black trace kicks over to the right, that's high resistivity, that's our oil-filled sand or water-filled sand. Of course, we're looking for just the oil, but this is our stacked pay. We take that information from our logs and in our drilling programs and bring it into an earth modeling environment where we're able to model the layers, model the vertical configurations and design our steamfloods.

We'll select pattern sizes, we'll select pattern configurations, a 5-spot, a 7-spot, a 9-spot. We'll consider deep, we'll consider the location of water. The design of a steamflood is first order driven by geology, just like water flooding.

So let's take one more step and let's go inside of the Kern Front field. This is one of our larger steamflood assets. What I'm showing in the graphic on the right is those pattern group shown in different colors.

Each one is labeled by the start-date of steam injection as a pattern group. You notice they're all of different configurations and size. They are oriented -- they're oriented relative to things like faults, these blue lines, and they are operated as an entity.

What I've done is I've bored down into one of those pattern groups, the 2006 pattern group here and I'm showing a bright yellow dot. We're looking now into one of the observation wells in that pattern group and it's shown on the display on the left.

Now, this is a display taken from one of our surveillance tools that we have where we're taking data in from logs, from our surface measurements, and we're integrating it into a display that's telling us what's happened. So let's take a look at this display.

On the far left of the display are a series of numbers, those are depths, so normally going from 1,000 feet, down to 2,500 feet or so. The next is a bunch of letters. We label every sand layer so we can speak with a common language between geologists, reservoir engineers, operating engineers.

Next is the dark black trace. When that black trace jumps to the right, that's the sand, when it jumps to the left, it's a silt or a shale. The silt and shales are barriers. The sands are filled with oil and they are our targets.

Next, we have -- that you'll probably see is this big red trace, that's temperature. The scale for temperature is on the bottom of the plot, zero to 350 degrees.

The interpretation here and then the green trace is another log and a log that looks to see where vapor or air is within the sand. By integrating all of those measurements, we come to an interpretation that shows us I have hot draining sands that are shown in the red bars.

So at the time of this logging, I know exactly which layers are heated, I know exactly which layers are in the state of drainage, and in fact, within each sand, if I could point out to the bottom red bar, I can see how much of it is filled with steam and how much underlying oil remains within that sand.

As I take these logs sequentially over time, quarterly and annually, I can actually follow the heating process arrival, the heating process enabling the drainage and then watch the sands drain over time.

Now, it gets to the recoveries that Vic was talking about. Where you see steam in this field generally, you're at less than 5% oil saturation from what might have been initially 50%, 55%, incredibly effective recovery where steam enters the rock.

The opportunity to get the 70% recovery over the whole field involves getting that steam all the way down to the bottom of every sand. So previous operators, if they were injecting at high rates of steam and their sands are draining and therefore the production rate is declining, they lose economic bounty halfway through the draining process and leave the layer and go to a new fresh one.

So this target you hear about in our proposal are some of the hot remaining oils that are left in sands that were previously steamflooded. If you think about it, the earth is actually a thermal insulator, these layers, the 300-foot thick interval here -- 150-foot thick interval, 300 degrees plus, that will stay over 200 degrees Fahrenheit for 20, 30, 40 years.

It's a wonderful opportunity to go in someone else's old steamfloods and find oils because in the day, they didn't know to reduce steam to allow the oil to drain all the way to the bottom.

The other thing I would point out to you is we've talked about stacked pay in future vertical recompletion, as Vic mentioned. You noticed how cold it is at the bottom of the temperature trace. All of those sand layers below are future steamflood opportunities within this pattern group that are underlying the current active steamfloods.

So we have tremendous vertical expansion opportunities as seen here within our steamfloods as well as aerial expansions. So we see four layers that are hot, they're draining, so what's the right level of steam, how much do I know to cut steam.

I have a performance plot here now. The vertical axis is in barrels per day. The red is steam rates. You can see that this project was the one we were looking at. It started up injection in 2006. Each of the vertical lines, by the way, is the year.

You can see that I started injection in 2006 at nominally 6,000 barrels of steam a day, and this kind of let's you know kind of the rigors of operating a steamflood, the noise that can -- and the operations of trying to keep things running smoothly.

You can see next the ramp-up and peak of the oil production that was intended with that injection. Notice that the oil has started to decline were past peak and we've now established our decline.

Our interpretation for this project is we've reached maturity. When we couple that to the observation, well, we just saw where we had four layers of rock at 350 degrees, the opportunity to cut steam is strong.

The path we might have taken or most operators take and we have taken in the past is to trim our steam as our oil decline. The opportunity we're capturing today is to go for the thermodynamic minimum. We're turning the burner down to the absolute minimum to sustain the draining process without changing the decline rate.

So that's a pretty big steam cut. Does that really happen? We really do that honestly. You're moved -- you've just gone through peak, you're in decline, you think some things are getting worse. You know, you really -- do you want me to take a huge steam cut? The answer is yes, that's where the -- that's where the value comes from.

Often in an old steamflooded field where previous steamfloods were applied, you have the opportunity to look back in time. So here was the initial development in Kern Front back in the day. This is the performance plot for that pattern group. What do you see?

You see startup of high rates of injection dedicated into these patterns. You see a ramp-up of oil production, a peak and a decline, 4,000 barrels a day, it had a peak. You see this well established decline that has been best curve fitted with this blue trace. That decline reflects this draining tank of heated layers in the steamflood.

You also see demonstrated performance of massive steam cuts. Now, back in the day, that steam cut might not have been seen as a steam cut as much as a response of crashing oil prices. I can't afford that high level steam. I'll reduce steam to make money.

Today, we see that as an optimization, a steam cut that demonstrates that when I make these huge cuts, I don't alter the drainage path at all. So that's a lot to swallow. What do I have in real life that helps me believe this stuff actually works other than, you know, looking back in time in a steamflood?

I have an analog for you that might help you to wrap your mind around it a bit. It comes from a culinary world. You can think of steamfloods in this analog as something akin to making an egg salad sandwich.

So our enterprise in heavy oils to produce the oil, sell it and make financial gates that allows us to expand. Our analog is we're hungry, we need to make a sandwich to satisfy our hunger, so most of us have probably made an egg salad sandwich at some point in time.

What we'll do is we'll go into the kitchen, out a big pot of water onto the stove, put eggs into the water and we're hungry, so what we do is we turn the burner on full. We really got to get that water heated up. We wanted to get to a boil so that our eggs cook as fast as possible.

Now, the interesting thing about these eggs are, you could take that burner and leave it on and boil and water splatter all over because you got it on high burner. But what you could really do is turn the burner down to just sustain the boil.

You're not changing the temperature of the water at all. The cooking time of the egg is unaffected and you're literally saving an enormous amount of gas. You take that gas, out on another pot and make some more egg salad sandwiches at the same time as an example of what we do with steam. When we turn down the steam, we take that steam and aerially expand, vertically expand with the same capital investment.

You can think of it as protecting the base. We maintain and protect our margins by this action. So we're driven to operate that burner by our need to protect our margin and optimize our steamflood.

The process for managing that water boiling in making the sandwich is your eyes looking in the kettle and maybe your ear hearing the boil. In our steamflood, it's our observation wells. We're looking at temperature. We're looking at where steam is in our patterns within the pattern group.

We take the derivative of the temperature curve to calculate the exact amount of heat leaving that steam chest and we dial the steam down to that level, and that's what's demonstrated in this picture here, all be it, it took them a while to get down to the ultimate thermodynamic minimum.

Our opportunity here could have been to follow that trace. We could have made that cut sooner, the pot was boiling for a while before we turn the burner down in this steamflood. So that's a little bit of what optimization looks like in a steamflood and how we can manage these things to generate and create real value.

I'd like to take you out Kern Front so you don't believe this only works in Kern Front. And I'd like to show you what another operator struggled with. This is the Lost Hills field. The pattern groups are shown on the left display. The colored pattern groups are pattern groups that CRC has installed and they are operating.

The gray colored pattern group is the previous operator's steamflood. And what I've done is I've extracted an observation well from kind of the center of this thing. There is several located throughout this project.

And I put it on this graphic display on the right. And now, looking at this and seeing the vertical track. The first thing I'd bring your attention to is the numbers, 140 down to 460. This is the world's shallowest steamflood. Lots of operating challenges here in pushing steam to rock that is so close the surface.

So it takes great expertise to do this well. Unfortunately, we've got the team that does that up in Lost Hills. We take our temperature survey. We take our steam ID logs and we can interpret what is happening in every single layer in this spot in this previous operator steamflood.

And what do we conclude by looking at it, one [skinny] little sand has all the steam in it that has delivered all the heat. This big sand up here and the lower big sand are where all the oil is and where it's cold.

This represents the CRC a tremendous vertical reconfiguration of steam injection. The previous operator had targeted all of the oil sands but what, in fact, happened in the steamflood is all the steam short circuited through a minor layer.

Why did it go through that minor layer? It doesn't really matter. It went there. We've injected steam through the previous operator for seven years short circuiting. So this is an example of what optimization looks like, the level of surveillance and its importance in managing steamfloods to get the maximum financial impact, the maximum oil recovery.

Oil recovery in the steamflood, as you can imagine, up to the point of CRC reconfiguring it was very poor. So where do we go from here? What kind of runway are we talking about? This is a kind of a graphic display of aerial expansion potential in our two biggest thermal assets, Kern Front and Lost Hills.

And they represent planned pattern groups in aerial expansion. What's not shown in Kern Front or Lost Hills where the colors are missing, those are the active steamfloods currently, all the vertical expansion that is currently being inventoried.

And like Bob showed, it's out there in the contingent being worked into the [VC1] and then it will be brought into the [VC2] at 1.3 categories. So this is the stuff the teams are working on. It's the vertical recompletions to bring our steamflooding process to complete recovery in these fields.

So how do I believe you? I mean do you really know what you, guys, are doing with steamflooding? Here is -- here is kind of a history and future for steamflooding in CRC thermal operations.

You see back in the far left we were at about 11,000 barrels a day. We've risen to 23,000 barrels a day. And our plans have us going well above that. And again, the nature of what that curve will look like is based on our capital allocation.

We have a deep inventory, if we apply a lot of capital to it, we'll arrive that of a curve. If we have other places to spend our money because some exploration well is attracting all of our money at that time, we'll -- without investment, we'll arrive the low decline curve from our current state of production.

Kern Front, Lost Hills and what we call our advanced properties are shown. We'll be visiting one of the advanced properties later on in the day today.

So okay, your group production, are you making any money, low oil price, we're in a down cycle. We've been there in my career four times. So this is very familiar territory. And as Vic pointed out, it represents to us in the thermal world a tremendous opportunity.

It's where we really sharpen the pencils. We really take the effort to get down to the thermodynamic minimum and extract that steam and placing a new steamflood.

Here's our run rate for 2015 low oil price environment. Shown in the diamond is our realized crude price in these projects. And shown on the bars is our percent margin as a percent of oil price. So even during our current year low price environment we're having robust margins in our steamflood processes.

Lastly, I would leave you with the picture of a typical Kern Front project. This represents the upfront investment in facilities and wells, the startup of injection in that well operation, the tailoring of steam injection as you see in years three, four, five and six an eventual shutoff.

Like our eggs in the hot water, as we approach the eggs being fully cook, we can actually shut the burner off. There's enough heat in that water to complete the cooking of the eggs. That's what is happening in our steamfloods. We literally thermodynamically glide most of decline life of these mature steamfloods. And also shown is the kind of lifetime these things offer.

Let's see if we achieve our objective. I hope I left you with the notion that steamfloods have large upfront investment. They deliver strong margins. They have stable and long-lived lives, gentle declines, well predictable, and they have strong backside cash flow delivery that creates the real value from steamflooding and represent a tremendous potential within CRC's portfolio for capital allocation and balancing our other upside opportunities.

I'd like to open it up for questions at this time for both Vic and myself. If you have any questions about thermal, we'd be happy to address them.

QUESTIONS AND ANSWERS

Todd Stevens - *California Resources Corporation - President, CEO*

I'll get Vic to back up here too.

Unidentified Audience Member

Thanks. I found the analogy in 1980 is when you mentioned that it was the down cycle that created a number of technological advances, pretty interesting. Now, here, we're in a down cycle.

You talked about some of the technological improvements, desktop computing, surveillance, getting to that thermodynamic minimum. Are those technologies that are the result of this down cycle, does it sound that way, or are there anything -- is there anything on the table that you see that could be as impactful to improving the economics of steamflooding as what we saw over the last down cycle here?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

We'll kind of focus on execution in my thinking out loud about that, I see the biggest potential in this down cycle to align our teams from the operators to the plants to the engineers, geologists and leaders, decision makers to come to this common view of how to operate to the thermodynamic minimum.

Right now, at a high price environment, you know, we tend to run our steam longer before we make our adjustments and we tune our adjustments to our decline because it represents kind of like an investment portfolio, a little bit of conservative, you're not putting anything at risk and you can cover it with high price.

In low price, it drives us to efficiency. I think the biggest gain we're going to get out of this low price cycle is alignment around being incredibly efficient in every single layer.

Unidentified Audience Member

Jeff, maybe can you talk about -- you [board] the Chevron alumni and they're doing 40 seismic at Kern River. I mean that -- some of this were cutting edge. I think there's nodal seismic in the wellbore. That's probably today the most obvious kind of new thing that people are experimenting with.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Actually, what I see as a real benefit in this particularly cycle is cycle time than used to be in '86 and that time period, the tools that the engineers and the geologists had required time in order to do the thermodynamic minimum calculation, gather all the data. It would typically take a week in order to do all that.

These days with the desktop computing that we have, the interconnection of all the automated data acquisition, of the pattern analysis that would take us a week last 20 years ago will take us a couple hours.

So we should be able to look at the heat management of our projects in a weekly basis and be able if it's needed to make the adjustments very quickly.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

I'd like to add one opportunity that I am enthused about. I showed the steam at the top of those layers at Kern Front and the remaining oil. That oil has to travel through 5 acres to get to get to our producing wells. If it does so, it takes a long time.

An opportunity is to lay horizontal wells on the bottom of those sands and drain that oil much quicker. It even improves recovery because often oil continuity, same continuity between injector and producer is not 100%, and it gives us the opportunity to pick up bypassed oil. So the introduction of horizontal wells into existing draining heated targets is a big potential. And we're working to deploy that.

Todd Stevens - *California Resources Corporation - President, CEO*

To address [Brian]'s question a little bit too, Vic, you had noticed, but moonlights as a professor of engineering at USC. So -- but he has probably evaluated and looked at.

People are looking at how to downhole preheat oil, lots of things. I mean none of them -- and I think in your mind have been commercially successful but there is a lot of technology work going on in this area.

It's just not clear that it's going to be commercially viable. I mean maybe you want to comment on, Vic, that, like I mean you've seen everything from the downhole pumps and preheating chemicals and all things we tried to do when they talk about heavy oil.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Well, just '86, we've learned a lot of things. I mean there have been some improvements. We kind of talked about that. There have also been some real key disappointments.

Disappointments would include like downhole steam generation. This just doesn't work primarily because of operational considerations regarding corrosion and the effect on the mechanical integrity.

Chemicals, we've had technical success putting chemicals, foams, surfactants in order to improve recovery from thermal operations. They're technically successful but they're not commercially successful.

Unidentified Audience Member

Yes. Jeff, to what extent does the infrastructure associated with the existing and the future steamfloods inventory been prebuilt? And can you -- I don't know how you (inaudible) quantify what the associated incremental capital would be to meet your fund through 2020 but bearing in mind I guess what you're explaining about, been able to just steam in one well, I guess, you move onto another. So I'm trying to understand what the capital implications out of your plan?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes. In both Lost Hills and Kern Front, we think our kit is adequate for our strategic plan. Can we accelerate our plans? Will we find more targets in our vertical inventory? Yes. Will we be able to extract enough heat to fund all of the new or will we need to make incremental investments in facilities? It's a lever we can pull.

If we want to go faster, we can get to a higher peak for a shorter period. If we want to be incredibly capital efficient, we'll use our existing infrastructure and schedule steam through vertical and aerial expansions as fast as that steam can be liberated.

So it's really a tradeoff for us and we can manage through our cycles, commodity cycles so that we aren't building huge plants and then not filling them. Our current plant at Kern Front and Lost Hills can handle our strategic plan but we can accelerate and we can make further investments if we choose to.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes, I know which one you're talking about.

Unidentified Audience Member

(Inaudible). That trajectory, the only incremental capital then is the drilling capital as opposed to facilities.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Right.

Unidentified Audience Member

Thank you.

Unidentified Audience Member

For the sandstone reservoirs, are they typically well cemented, do you have good interstitial cements on these targeted zones?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

The observation wells?

Unidentified Audience Member

No, just the wells that you're actually producing from.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

And could you say your question one more time?

Unidentified Audience Member

For the --

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

So there are consolidated sands.

Unidentified Audience Member

Yes, that's what I'm wondering, the consolidated sands.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Typically, what we'll do on our producing wells is we'll put sand control techniques, grab flow packs, the principal method that we use to prevent sand -- reservoir sand coming into the wellbore.

Unidentified Audience Member

And then what's the average porosity?

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Effective porosity will be in the high 20s, total porosity will be in the -- around 30% to 35%.

Unidentified Audience Member

Just a couple of questions. The chart that follows this one, so it's page 81 on there, the variability between any given price in the margin, what -- I know typically, I don't get in a month to month data, so, you know, financial analysts (inaudible) attack it if I see it.

But what would drive the variability for month to month, is that steam on, steam off, is it gas prices went up, I'm just curious?

Todd Stevens - *California Resources Corporation - President, CEO*

All of the above. We've got a lot more.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

It was in attempt to show you that, you know, this is a moving target. Steamfloods consume as fast as you can invest in them and operate them. They also can be as efficient as your management and execution allow.

So within the month to month operation, I was hoping you pick that up in the steam injection, you know, profile, actual versus, you know, what it -- it's just the day-to-day execution. And then the -- in start up and stopping of operations that occur within a monthly timeframe that drives a lot of that.

Todd Stevens - *California Resources Corporation - President, CEO*

What we really wanted to show you is like -- because we knew that would beg the question but it's about management of the reservoir and how it's managed.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes.

Unidentified Audience Member

okay.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Good point, Todd.

Unidentified Audience Member

And then my -- my other question, you showed, I guess it's chart 72 or 73 where you showed the various layers and the sands and as you move down, the -- this is probably 74 or 70 -- you know, like that.

As you move down in depths, and I know these are not great depths but is that -- how much of the effective cost on that? I mean I just think of injection being, you know, a pretty high cost compression. So as you go down, is there any material cost impact we should think about here, that impact?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes, yes. In Kern Front, our practice is, as Vic described, use sand control completion. And in our producing wells, we generally have the entire layer cake open in the producing wells.

It's just the injectors that we move the heat around from and the performance is drained by the producing wells. That way, as heated layers are still slowly draining, that process occurs while we're going after new layers.

So the process of well costs with going deeper is generally born by the injectors if we can't recomplete any injector deeper.

Todd Stevens - *California Resources Corporation - President, CEO*

Well, Jeff, you can scale like how -- it's not material when you think about it, how these wells cost?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

The typical producer in Kern Front is $400,000 to $450,000, so the injectors are cheaper.

Unidentified Audience Member

I just want to make sure I understand this. And so over the life of a project, it's 5 barrels of steam per 1 barrel of oil. Am I reading the computation right?

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

okay. Yes. Kind of the metric, the health metric of the steamflood is the steam to oil ratio. And good steamfloods will be at a 5 SOR. Okay, that was an example calculation where again, you get 2-1/2 barrels of steam per mcf of gas that you burn.

If a fuel gas costs $3 an mcf and you're operating at a steam oil ratio of 5 then your steam costs are going to be $6 per barrel of oil that you produce. That was the example calculation.

The key point here is typically fuel costs during the majority of the heating period of the steamflood account for about 50% of your total operating cost.

Unidentified Audience Member

okay, maybe a comment on steam-oil ratio, world class versus, you know, people do projects of steam-oil ratio in the excess of 10 so.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Yes. It's going to depend on the cost of your steam. Early in the life at Kern Front, Oxy had the ability to get very, very cheap steam so you could operate projects at steam-oil ratios of 10 and still make a lot of money. Again, it's going to depend on the cost of your fuel gas.

Normally, we tend to think anything with $3/mcf gas and oil prices where they are now, anything over an SOR of above 10 is you're going to have very low margins.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Can I add one thing? I want to develop a little bit of your sense of SOR. When you start a steamflood, the SOR is infinite when you -- because you're injecting steam and you're not making oil yet in day one.

You know, in the tail out of a project, when you're injecting no steam, the steam-oil ratio is zero. So the instantaneous steam-oil ratio very significantly over the lifecycle of a steamflood and the numbers that Vic was just talking about are kind of the cumulative SORs that are the, you know, real arbiters of value creation, you know, looking back on the whole enterprise.

But in our day-to-day operations, we're focused on the heating and draining process and letting the steam oil ratio reflect the efficiency we gain. We're not driving our steam flood decisions based on the SOR.

So good quality rock, well saturated and incredibly well managed, that's cumulative SORs around 3-1/2. But, you know, getting to a cumulative steam oil ratio over a very large reservoir with multiple steamfloods is a pretty complicated process. So anchoring on a single number is simplistic.

Unidentified Audience Member

That's helpful. And I want to follow up, can you give us a sense maybe on average of what the facility and drilling spend per barrel of oil per project would be?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Refer to slide 80. I can't read the number from here, 82. Those are real numbers. They aren't numbers but they are magnitudes from Kern Front steamflood.

Todd Stevens - *California Resources Corporation - President, CEO*

On a percentage basis, I think we could fairly say, historically, it's been, for instance, a 30%, is that about right? And we think going forward based -- we're operating them differently. It used to be, you know, in -- these guys are working at Chevron, you'd build all the facilities to accommodate the biggest flood ever and then you start filling your patterns.

Now, you're optimizing pattern by pattern and you're moving steam generation around, you're moving facilities around. So we think going forward, it's going to be closer to 20%. So there's really a lot of optimization and management going on.

As you heard from Jerry yesterday on waterflood, this is same on steamflood. It's reservoirs -- our surveillance and conformance, those kinds of things are critical. That's why, you know, people like this are critical for the success of our organization in all the people that work with them.

Unidentified Audience Member

Thank you.

Unidentified Audience Member

First question, to better understand the total LOE cost per barrel for the steamfloods, you gave an example of $6 as energy cost and that's about half of the total cost which should imply about $12. My understanding previously was about $20 or more a barrel. Can you just provide us some color?

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

That $6 per barrel of oil is just the fuel gas cost. In addition to that, you're going to need to treat the water to get it ready for steam. This doesn't include the lifting cost, the energy associated with the beam pump units, the hydration of the gross fluid that you're producing and the disposal.

Unidentified Audience Member

So I have questions more. Am I wrong to assume that the total LOE cost right now on the steamflood is about $20 a barrel or higher?

And then maybe implicit -- the slide 81 you have on there where you cite the margins, that implies an average cost of about $25 a barrel. Maybe just, you know, help me understand what's in that $25 a barrel, is that mainly LOE plus taxes?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. I think your LOE question is less than $20 on average on LOE. But if -- this is kind of taking up kind of operating margin. So we're including, you know, field level G&A, production taxes, pretty much everything that's kind of a cash margin for us.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

That's good, right.

Unidentified Audience Member

And then my second question, so you've highlighted in here and I think in every investor presentation that the steamfloods are, you know, attractively economic at a oil-to-gas price ratio of 5 to 1, right? So the current gas prices at $3, that would imply $15 oil.

And I guess I'm just trying to better understand what that really means like clearly, if we have LOE costs of -- let's just say, $15 to $20, plus taxes plus capital cost plus the margin needed to make these investments economic, what is that chart -- what is that statement really telling?

Todd Stevens - *California Resources Corporation - President, CEO*

You're talking about on the margin too so you're assuming that, you know, you're managing the business, you have an up and running steamflood so it's really what is your LOE going forward.

Now that Vic talked about it because I think there's a lot to do with how we manage the steamfloods as Jeff talked about, you can turn off the steam effectively. And you'd sit on this very shallow decline and we saw Mt. Poso, I mean they didn't -- it stopped injecting steam wind there in 1990, maybe.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

1991 and --

Todd Stevens - *California Resources Corporation - President, CEO*

And it would still -- I can't remember, what is it, 300 something degrees in the ground, so it gives you an idea that they hadn't been injecting there, you know, for 30 years and still hot.

And we're waterflooding a different zone but that just gives you an idea of about heavy oil reservoirs but I'll let Vic talk about, you know, the other questions of operating cost, how we manage it.

I mean the steam-oil ratio, because it's such an important part of your cost, you know, going forward, and that's something you manage where you could turn it on and off depending on the product price environment you're dealing with.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Yes. Typically, and I think Jeff touched on this too on his last slide, is you'll focus on the reservoir heat management and you're going to dial back the heat because rock stores a lot of heat and one way to manage a steamflood effectively is to dial back the heat and pump your wells as hard as you can to try to reduce the pressure.

If you can get the pressure lower, below the saturation temperature of steam, you're going to flush the water that's in the porous bases and generate steam. So that's a very effective method to keep a steam flood going even when you turn the burner off.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Can you restate your question one more time? Because I think I want to help with understanding these things too simplistically will make you think that they all perform, you know, in a consistent manner and in a generally understood level that our steamfloods have dramatic behavioral differences, and life behaviors that have to be managed for optimization.

So in the aggregate, you know, you arrive at instantaneous and cumulative numbers that we speak of but in individual steamfloods, it's more about the physics and the thermodynamics that control the outcome ultimately financially.

Unidentified Audience Member

The simple question --

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes, yes.

Unidentified Audience Member

The simple question is that statement says that at $3 gas, that this is economic and attractive at $15 oil. And I just wanted to better understand what that meant because clearly like to drill new cap -- it sounds to me as if that means you wouldn't shut in production at $15, you would keep this running, but clearly, it's not economic to drill new capital.

Todd Stevens - *California Resources Corporation - President, CEO*

You would manage it differently, [Sean].

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes.

Todd Stevens - *California Resources Corporation - President, CEO*

And they'll tell you in '86 when gas was $1 and oil was 10 bucks or, you know, whatever it was at the time, depending on the time it's in, you still managed it that way and it's still producing, as Vic was showing you, 400,000 barrels a day.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

We have a lot of potential for vertical expansion that doesn't require much capital at all as an example. And we blend that in with the aerial expansions that do require the well drilling. So it's a managed development I guess I would call it. I might have to talk to you more about that later. I'm not sure I understand what the -- what you're asking.

Todd Stevens - *California Resources Corporation - President, CEO*

You know, I think what [Sean] was saying was that, you know, we've talked about basically if it's more than 5 to 1, the economic will work as the rule of thumb.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Sure.

Todd Stevens - *California Resources Corporation - President, CEO*

And so how would you -- and that implies $3 gas, it's economic, you know, on the $50 Brent. So why -- how would you manage that? And what we're trying to articulate and maybe we're not doing a bigger job is, you know, we have a lot of levers to pull, to dial back OpEx and to dial back what we do in the field to manage down to that if we had to. And that's the very short version of it.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Todd Stevens - *California Resources Corporation - President, CEO*

I'll let Jeff go ahead and talk about how you would manage the reservoir. I mean some of that is production taxes too so obviously, in the low price environment, you can take two or three bucks after that.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Well, the thing to keep in mind in that example calculation was the assumption of an SOR at 5. Okay, higher SORs are going to have different impacts.

Unidentified Audience Member

(Inaudible -- inaccessible microphone) you have a 50% cash margin at $15 oil.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Simple, here, okay, a $3 gas, if you have an SOR of 10 instead of $6 per barrel of oil, your fuel gas is 12.

Todd Stevens - *California Resources Corporation - President, CEO*

No, he's trying to say that if oil was $15, $5 per barrel and we had $3 gas, and we're back to your 5 SOR, you know, how would you manage the LOE down, you know, and what have we done in that environment historically?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes, the biggest lever we have is reducing our steam to the thermodynamic minimum. So that first steam cut we made is 70%, and that's the opportunity available.

So really, what we would be doing is assessing which of our pattern groups were in what stage of lifecycle. If they're immature, we've got to keep the burner on full because you're on a path, you're setting up a thermal transient that's getting you to the state of maturity.

Go back to the boiling egg. As the water is warming up and it's just starting to come into a boil, you turn the burner down, you'll lose that build up, the water will gradually cool. Now, to re-establish the burner to get it back to the boil now that you later on decide to do that, there's a huge hysteresis.

So the first thing we would do in a low price environment, $15, you know, we're not making money. It's about in anything new, in anything immature that there are pattern groups that are entailed out in certain layers, those will make money easily at that level because you can basically shut off injection.

How much of that we have, where it's had aerially, where it's had vertically is kind of the automation process and surveillance process that Vic is talking about that our engineers quickly go into.

If we haven't started the project yet or we just started turning the burner on, we'll shut that off. That's not going to make money for a long time.

All the stuff that is already in rolling boil of the burners way down on it and you've got 10 more -- 5 more minutes till you cook the egg, that's [what stays on], that's making us money way down the scale.

So it's about the management of where is the maturity, where is the immaturity, what layers, what areas, and sustaining -- doing no damage. If you're almost the peak production, you've been feeding in the immature rate all this while, the price of crude collapses, I mean you're in a really high steam oil ratio at that point. It looks horribly uneconomic.

But the second you get to the state of steam overlay, and it happens in days, you're making 70% heat cuts and you're writing the thermodynamic [life] for the rest of the project.

Todd Stevens - *California Resources Corporation - President, CEO*

And I think this question really if you think about it to is LOE. And if you're in different part and different patterns of the lifecycle, the LOE is different.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

That's it.

Todd Stevens - *California Resources Corporation - President, CEO*

I mean that's the thing I think that we haven't articulated is depending on where you sit, we're giving you an average across all the patterns as opposed to you're really immature earlier on or you're in steady state or in a maturity state.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Yes.

In the back please?

Unidentified Audience Member

Thank you. Jeff, in the slide 71, could you give us the OpEx breakdown and idea percentage basis depending where we are in the cycle? Knowing the lifecycle, when you have ramp-up -- yes, this one.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

This one, okay.

Unidentified Audience Member

Yes.

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

Can you restate your question please?

Unidentified Audience Member

Sure. Just in OpEx breakdown depending where we are, for example, 70% ramp-up?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

So -- sure. So in the immature state, your steam is driving your op cost. Well servicing cost which can be 30%, 40% of the costs of an ongoing steamflood are minimal because the heat hasn't arrived at the wells yet.

When the steam breaks through into these producing wells, we're getting high velocities, sanding problems, emulsion problems, steam cut tubular, it's a very violent process inside the producing well.

So the OpEx is high due to high steam rates in the immature state. As steam breaks through at peak, that cost grows by well operation problem in addition to the steam. And then the OpEx drops dramatically in the mature state.

Once those steam cuts are made, the velocities in the producing wells drop dramatically. Sanding problems disappear, emulsion problems, steam cut tubular, all of the difficulties of operating those wells dramatically abate.

So it's literally your cost can go dramatically lower in the mature state. Later, we're even shutting in the steam and thermodynamically gliding by the energy that's in the rock from our injection process over time. So it's high, gets even higher, and then it's low for a long time.

Unidentified Audience Member

On a percentage basis, just to give us an idea, for example, the ramp-up phase would be 60%.

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Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

You know, I had never really sat down and added it up. Vic, how about you?

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Well, typically, I guess to put $1 per barrel number I tend to think of that better than percent of the price, but I'd say typically in the ramp-up and the peak period, you're in the $20 to $25 per barrel range. And then when you get down to no steam injection at all then you're probably in the $10 per barrel range.

Todd Stevens - *California Resources Corporation - President, CEO*

Who do we get?

Unidentified Audience Member

The order of magnitude of savings going from the traditional decline in steam injection to the thermodynamic minimum that you talked about, if a project has a five times steam to oil ratio going from that traditional method to your newer method, what would that five times drop is, what was it like?

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

It's really big. Yes, it's really big. You know, I can just give you some ballpark numbers. If you're operating at SOR of 5 there at the peak, let's say, you're -- let's call that accumulative up to that point, a 5 when you pay that off. When you reach zero steam injection then you're probably going to be more -- about half that amount.

Unidentified Audience Member

Jeff, I think you mentioned possibility of drilling some horizontal wells to improve recovery factor. I guess number one is what's the associated cost with doing that?

And, you know, can you talk a little bit how that may change your free cash flow profile that you laid out? Can you help us understand the economics of doing that versus kind of what you've traditionally done in the past?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

We've drilled a number of horizontal wells in Kern Front. We're dialing in the trajectories of these things to be laying in just the bottom of the sand and we're deploying technologies for doing that.

Those wells have been running about 2-1/2 times the cost of the vertical producer. So they're still very affordable to us in the field and we have opportunities to optimize that to less than that, but the first wells we've drilled have been about 2-1/2 times.

Unidentified Audience Member

Thinking about the economics of doing that vertical -- you're typical vertical producers, what -- what's the payback on those horizontal wells versus kind of the typical?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

We have one well so far that has achieved our objective, it was drilled years ago but it did exactly what we are designing to do. That well produced 140 barrels a day, so it -- that is quick. And you're not applying any new steam, the sand is already hot, the oils were already heated, they're ponded.

So the process is basically drilling and operating the well and receiving the kind of productivity that we expect in a horizontal inflow performance configuration. A very upside -- strong upside potential development opportunity that we're developing and finalizing technology where other operators have used this technology successfully.

Todd Stevens - *California Resources Corporation - President, CEO*

okay.

Unidentified Audience Member

Just conceptually, what does it take lower commodity price to change how you manage the reservoir? If that's the way to do it, why not do it that way all -- you know, the entire way or --

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

That's the opportunity. At the end of the day, a risky process, it's never completely clear except looking backwards. When the moment arrived for the opportunity, when the eggs are done cooking or when the boil has arrived and you can turn back and exactly how much, doing that with no eyesight on the boiling water, you know, 1,000 feet down involves uncertainty.

And the strongest motivator for taking a risk is, I've got to do it to stay as the commercial enterprise. So low oil prices incentivize working further to the left on the risk reward, you know, spectrum.

High/low prices don't incentivize that. You're really more interested about producing every barrel and gees, I know I could think of steam cuts and not lose barrels but I also know if I do it too soon or I do it in the layer that's not fully mature, I'll hurt production, so a low oil price incentivize commercial risk.

Todd Stevens - *California Resources Corporation - President, CEO*

Well, also, I think it really -- it goes back to '86 where I don't think any steamflood was optimized. And they were just putting in the ground and oil was coming out. They wouldn't -- Vic could speak to this, you know, firsthand.

I guess this is -- that oil price downturn really caused the heat management, the surveillance that go on in the steamfloods.

Vic Ziegler - *California Resources Corporation - Director - Corporate Development*

Yes. The background there was steamfloods were operated like waterfloods, continuous, constant injection rate until it became uneconomic, the SOR became uneconomic. The '86 crash made us look at the thermodynamics, what was going on, what was the orientation of the steam zone? You know, that before, pre-'86, people were thinking the steam zone was going to advance like it would in a waterflood like pistons, maybe multiple layer of pistons moving from the injector to the producer.

At '86, we started drilling observation wells like Jeff described and seeing the actual geometry of the steam zone where it's writing across the top. And it's not a frontal displacement type of a process.

Essentially, it's a gravity drainage process like Jeff was talking about just opening the valve at the bottom of the well. You know, we used to think -- we call the wells like at Kern Front, we call them sands with pumps. You're just draining the sand.

Unidentified Audience Member

If you're -- if you're operating with a certain margin of safety when commodity price is high and then you change how you operate it, does that mean that risk has to go up somewhere somehow?

Jeff Hatlen - *California Resources Corporation - Chief Reservoir Engineer Thermal Operations*

No, it doesn't have to. You know, as an organization, well, we will drive ourselves through this opportunity. We'll demonstrate success in our action and it will embolden our teams to take a more practical view, a picture of pattern group, 10 patterns, you have three observation wells in it.

Every patterns pumping, you know, production 10 barrels here, 50 barrels there. You're trying to look in each layer to what state you're in so that you can make a change in your injection. Two patterns over here, look immature, eight patterns over here are well matured.

In a high price environment, you might hold up the whole 10 patterns for those last two to come into maturity so you can take a cut with no risk.

In a low price environment, you need to get to that 70% cut, so you might bifurcate that pattern group into two patterns and eight patterns and make the cut in the eight patterns as an example.

You have fewer observation wells, you're taking a little bit more data of surveillance risk but you also get feedback. The next temperature survey, the temperature drops, you know, you've under injected.

So there is -- low price incentivizes actions that can be risky because of uncertainty. And I'm willing to take more risks with the higher level of uncertainty that gets me to a commercial outcome that's much stronger.

It's that first cut that is so big. The opportunity you want to get to it soon but if you -- if the water hasn't come to a complete boil yet, you turn that burner down, it hurts production.

Todd Stevens - *California Resources Corporation - President, CEO*

I'm going to cut off the steamflood question to this point. And I want to give a chance. I'm going to wrap up and give everybody a chance for just general Q&A really quick to try to trying together we have most of the folks that we need here to help answer your questions.

But hopefully, you'll see that, you know, our former parent put together an outstanding set of assets here in California. And then they went into place and started building the infrastructure to give them the operating flexibility y and the operating control needed to be truly successful.

But these assets were operated as a part of a very large portfolio with different priority sets. And really the opportunity set at CRC is to bring the focus and entrepreneurial spirit. You heard from all of our employees and why they've left their prior employers in some cases and focus on these assets in the way they need to be focused on and operated the way they need to be operated on whether it'd be steamfloods, waterfloods or any of our conventional assets.

We're very excited about this. Elk Hills gives us an excellent opportunity for microcosm of what happens at CRC. It's currently 37% of our production. But, you know, right now, we've driven down operating cost at Elk Hills at around $10 per Boe.

Bob calls it Operation Alexander Hamilton and we joke about Operation, you know, Abraham Lincoln, but we'll wait and see.

But to give you scale, those costs were almost $20 of Boe not that long ago. You can look and see a few years ago, it was $16 and give you a feel for what's going on here. And in the meantime, our production has gone down, our wellbores have gone up and our water cut has gone up.

And this is going throughout the entire enterprise. This is the kind of attention and focus that it needs. And we've done this through focusing on our inventory and creating inventory, creating life of plans, creating real value, and that's what we've done and brought the discipline through our VCI metric, again, very transparent internally so that people understand what we're trying to create as CRC, how we're trying to create value, what we're trying to invest our capital in.

Because that's really -- again, like I told you earlier, the capital allocation by the employees and the management team is the most important thing you do to create value for shareholders over the long term. We're in a declining business otherwise.

So this is something that we take very seriously and that's why we use our VCI metric. We articulated all the way down to the operators so they understand what we're doing ultimately.

We're not -- we're not production-focused, we're value-focused. Like I told you earlier, this is -- we're going to do what makes the most sense. And that's why I think it's differentiating us, the CRC. We're bringing the focus, bringing entrepreneurial spirit to this set of assets that have been long neglected and then Oxy and to their credit, put them together and poised us for success.

We have delivered a balance sheet we're delivered with and we're going to work through that. And hopefully, we'll have some announcements to talk about some of the initial steps by yearend like I've talked about, but again, we're going to bring the kind of focus and attention needed and we are focused on things like we've talked about.

And hopefully you've heard the common theme, defend our margins, protect our base, and that's how we reorganize, how we allocate our human capital. We've got to focus on the base production. Huge difference in that 1% decline difference, so you can make those in every place we operate.

And then as you start to focus on defending your margins, focus on what's under your control, and hopefully, you've seen and as we've put up results, I know we're relatively new and immature as a management team, we do what we say we're going to do.

And we've been able to execute on things within our control and we're going to do what we need to do to make it through the cycle. And the one thing I will point out on Bob's slide where he talked about 1.3 VCI, those 1.0 VCI projects today, if you go -- if you talk about $65 brand, those are all 1.3 or greater.

And every project we executed on this year with our capital program had a VCI in excess of 2. And some of that -- and that's in the current price environment. And some of those obviously are projects that didn't start off with the 2 but they were working to that environment by great efforts by all of our employees.

And really, we have to compliment them not just here today down at Long Beach but the outstanding job our operations folks have done. And I'd love to take any more questions or comments. I mean we can bring Vic and Jeff back up if need be, but we'd love to answer any questions before we start talking about site tours and the like. Yes, sir? [Steve]?

Unidentified Audience Member

The and Robert talks about $200 million of midstream, so maybe a two-part question. One, what is that number on a corporate basis if you take all of your properties? And then two is, maybe use the 200 or the facilities there as the example, how important it is that you're the owner and operator of that?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. So that -- we don't calculate that internally. It's all part of it. So what we did was a little bit of an accounting exercise. We went out and we benchmarked against, if we had to replicate this, and whether somebody who's an operator in this area who is an independent have to pay.

So that was just for operations here in the San Joaquin basin, we think that it would be approximately $200 million a year to replicate, you know, spending to -- you have to do that.

But when you talk about operational control, just to give you a direct example, at our power plant here at Elk Hills, we used to have a partner in Sempra. And Sempra, it used to run as a peaker plant which didn't really work with how we want to operate the field.

So again, all those types of issues are embedded in all of our assets. And Bob really talked a lot about how Elk Hills is automated. But you'll see when you walk around the [CCF] today and Bob Summers will give you a tour of it, is we operate not just Elk Hills, we operate other fields adjacent.

And we continue to add more fields to how we operate this and ultimately, we -- I envision we'll add basins, you know, in how we operate from this facility. This is world-class.

He did himself a little bit of a disservice. People literally come from -- and I wouldn't name names but huge independent large majors around the country in the world to come and look at this facility in how we operate our assets in California. I mean it's something that we think has a lot of merit going forward.

But on the midstream infrastructure side, I think there is a certain level of operational control or influence you need to have to be successful longer term or you have to create it contractually ultimately.

[Jeff] -- [Doug]?

Unidentified Audience Member

(Inaudible) too much into this but that $200 million comment, are you trying to frame for us the potential EBITDA that could be available to be monetized, a midstream monetization?

And if not, to achieve your $1.6 billion debt reduction, what would be OpEx implications from what you know today be to -- you know, if you could take that increased operating revenue?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. I think I would just give you a little bit of a scale of the enterprise and also to talk about -- give you a scope of the value of all the -- just the San Joaquin infrastructure. I mean there's infrastructure elsewhere too but that was the commentary by it. It wasn't meant to give you any more than that. But as you build up a net asset value and realized there's real scope and scale here to these assets.

When we look at things, when we're trying to monetize cash flow streams out of our midstream assets or monetize them in some other way, we like to think about it in the terms of OpEx. You know, we're going to add OpEx and we're going to leverage that into something on our balance sheet, right?

And from my standpoint, we had about 50 million barrels of production, so $50 per Boe, I feel very confident that Bob and Frank and our team can extract that out of there. $2 is $100 million, so that's the kind of terms I think about and how I could monetize that.

And I've talked about yesterday and Evan was asking I feel like we're going to get accretive transaction, highly accretive transaction along those lines for us because otherwise, it doesn't make sense. You've giving up EBITDA. You know, you've got to get something that's going to help you with the balance sheet side for the longer term and the shorter term.

[Mark]?

Unidentified Audience Member

I had a quick question about slide 40, the VCI and inventory slide.

Todd Stevens - *California Resources Corporation - President, CEO*

okay. Somebody as quicker than I am.

Unidentified Audience Member

So if you look at the inventory in the top left, at the 40, yes, the inventory on the top left at the (inaudible) oil based on the 1.0 VCI, does that VCI minus standard include the 10% discount rate, correct?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes.

Unidentified Audience Member

Then if you -- then if you look at the bottom right at $70 oil, you have roughly the same inventory, a little bit more, a little bit less unconventional. So the extrapolation I'm trying to make is based on -- going from a 1.0 to a 1.3 is roughly a $20 difference in oil.

And so if you were to think about your inventory on a breakeven basis, like a lot of your peers do, like a 10% breakeven, would it be fair to say that that $20 delta is a [referral] of thumb or how do you think about that?

Todd Stevens - *California Resources Corporation - President, CEO*

I haven't thought about it that way, but I think it's a good way to think about it really when you look at it because it gives you a little bit of leverage to understand, you know, how leveraged we are to oil prices not just in terms of leverage but also from two operating standpoint, I think that's true.

And I think that's also an inventory slide that we -- came from slide 17 now, that -- and it also showed you the same -- the same thing, that kind of operating leverage. Because I think if you show that at 55 and you use this one for all CRC, you're talking about, is it over 2 billion, probably more that has a one VCI that you could layer in there at 55.

Unidentified Audience Member

Or I was thinking about potentially, you can take $20 off the low end.

Todd Stevens - *California Resources Corporation - President, CEO*

Yes.

Unidentified Audience Member

If that $20 you work, you shift everything 20 bucks.

Todd Stevens - *California Resources Corporation - President, CEO*

That's true.

Unidentified Audience Member

But --

Todd Stevens - *California Resources Corporation - President, CEO*

No. I think that's fair comment, yes.

Unidentified Audience Member

Yes.

Todd Stevens - *California Resources Corporation - President, CEO*

[Greg]

Unidentified Audience Member

So I think as part of your credit facility process, you have to deliver a reserve report -- a new reserve report to your -- to your [event] sometime next year. What's the -- what is the process right now in terms of -- or what's the thought process behind going to external auditors fully -- from a greater degree than what you've done in the past and what's the progress?

Todd Stevens - *California Resources Corporation - President, CEO*

That's something that we've -- it's been a little bit of a big effort for us because, you know, Oxy was audited reserve process, and we've gone and basically outsourced that function. We don't feel like it's a good use of -- from a smaller company standpoint of our engineer's time.

So we're using Ryder Scott. Elizabeth DeStephens is the one who is working on that for us and doing an outstanding job. We're in really good shape. Thanks to a lot of efforts by her and a lot of other folks and a lot of collaboration.

We have 90 days to deliver our reserve report under the springing lien that occurred. We feel really good about that and all the initial calculations which were really reflective of the Moody's report as even using bank price decks which all have a three handle, you're going to -- you're going to have no change in liquidity at the company.

So I think that's something that, you know, Moody's articulated in their report and they're (inaudible) a lot of information. So from our standpoint, we feel good about our reserve report and we'll deliver that to the banks and we'll -- you know, we're in the process of finalizing it as we get closer to yearend anyway.

I think -- I don't know of the exact timeframe whether it's the end of the fourth quarter or early first quarter, is it first quarter?

Unidentified Company Representative

We have 90 days to deliver the reserve report.

Todd Stevens - *California Resources Corporation - President, CEO*

And 120 --

Unidentified Company Representative

So that started from the -- the clock started ticking the day after the downgrade so I think it's September 16. So it will be near yearend to deliver the reserves.

They have their I think 15 days to run through the process as far as on their valuations and then run it through the rest of the bank groups. So effectively, you're talking about 120 days from September. So it will be around yearend timeframe.

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. And we've been very proactive. As you know, we've been reaching out and engaging all year long with the banks we have an early amendment, but then engaged as Mark and I talked about yesterday with them about an amendment to make sure we preserve all the ability to do the type of things we're talking about here on the joint venture side whether it'd be upstream or our midstream-type transaction.

Unidentified Audience Member

That report, are you seeing any major changes to the way Ryder Scott is looking at it versus the way you would look at it internally?

Todd Stevens - *California Resources Corporation - President, CEO*

No. What I will say is I think -- and give credit, Oxy probably is the most conservative reserve process out there. You look at their percentage of PUDs as a part of their total reserves relative to their peers.

They have a very expensive reserve internal process that makes sure it's right. So I think from our standpoint having Ryder Scott do them, I would tend to think they might go, you know, up if we're using the same product price profile simply because I think Oxy really is that conservative, wants to be right.

But, you know, we will have Ryder Scott. They have been the one that did the reserve audit process historically Oxy so they are familiar with the assets. And we've been familiarizing them with a lot of our other assets they might not have audited before.

So I think after initial pass and talking out, I think there's no issue at whatsoever with how they look at them, how we've looked at them historically or the like. So I think we're more focused really on the long term life of field plans and that's caused us to do a better job on a lot of things I think so that's -- that will make our reserves even better when they come out.

Unidentified Audience Member

Is that a full engineered report or is that audited, what's the --

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Unidentified Company Representative

80% of reserves.

Todd Stevens - *California Resources Corporation - President, CEO*

80%.

Unidentified Company Representative

80% of the reserves are reviewed each year.

Unidentified Audience Member

Then last question for you, just on the tax side, with less spending, there's potentially more tax liability or less deductions with less spending, how should we think about cash taxes going forward?

Todd Stevens - *California Resources Corporation - President, CEO*

I think the way we look at it, until Brent gets a 66 handle, I don't think we're a cash taxpayer at this point in time.

Unidentified Audience Member

Thank you.

Todd Stevens - *California Resources Corporation - President, CEO*

Questions, comments? Doug?

Unidentified Audience Member

Sorry, Todd, just one thinner one. Your last -- just from your preamble, you said production is not a -- not the important outcome, that's not what you're managing towards. If that's the case given that situation, why would you keep running at the minimum capital, meaning maintenance capital as opposed to attempting to add any new wells?

Todd Stevens - *California Resources Corporation - President, CEO*

Well, you're trying to -- you're trying to optimize that ultimately, right? So if we said -- let's say Brent goes to $20 overnight, how would you manage the business differently? We arguably have somewhere between 50 and 75 probably million a year we still spend on health environmental safety and mechanical integrity-type spending.

But again, we're - you could go into that mode but you're growing concern, you're trying to develop longer term resource and don't think that the current price environment is the new normal.

And so you're not -- you're not -- you're going to continue to invest, you're going to continue to do the things you want to do to create value for the longer term because if you stop the investment in the enterprise, you're really going to sure change yourself.

I mean especially when you think about all the opportunities that have greater than 1.3 VCI even in this product price environment. It just [pulls] you to invest those dollars to the extent you can, and that's all living within our cash flows.

How we ultimately build the business again, I think the -- you know, if we got back to a different steady state in our balance sheet, problems are, you know, behind us and we have -- we feel comfortable about where we sit.

I think you'll see us -- you know, we could easily start talking about growth at that point in time and still living within our means. And then you look at what's the best way to get a return to your shareholders at that point in time.

I think we're done for this part and we're going to have a quick briefing on the -- on the tour, right?

Scott Espenshade - *California Resources Corporation - VP - IR*

Yes. So thanks everyone for joining us on the webcast. We're going to end the webcast at this point but --

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