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# Cimarex Energy's (XEC) CEO Tom Jorden on Q3 2019 Results - Earnings Call Transcript

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Q3: 11-04-19 Earnings Summary

*Press Release* *10-Q* *Slides*

EPS of $0.91 misses by $-0.02 | Revenue of $582.3M (-1.55% Y/Y) beats by $6.27M

## Earning Call Audio

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Cimarex Energy Co. (NYSE:XEC) Q3 2019 Earnings Conference Call November 5, 2019 11:00 AM ET

**Company Participants**

Karen Acierno – Vice President and Investor Relations

Tom Jorden – Chief Executive Officer

Joe Albi – Chief Operating Officer

John Lambuth – Executive Vice President-Exploration

Mark Burford – Chief Financial Officer

**Conference Call Participants**

Gabe Daoud – Cowen

Arun Jayaram – J.P. Morgan

Neal Dingmann – SunTrust

Mike Scialla – Stifel

Jeffrey Campbell – Tuohy Brothers

Noel Parks – Coker Palmer

Drew Venker – Morgan Stanley

Betty Jiang – Credit Suisse

Brian Downey – Citi Group

Nitin Kumar – Wells Fargo

**Operator**

Good morning, and welcome to the Cimarex Energy Company Third Quarter 2019 Earnings Release Conference Call. All participants will be in listen-only mode. [Operator Instructions] I would now like to turn the conference over to Karen Acierno, Vice President of Investor Relations. Please go ahead.

**Karen Acierno**

Thanks, Gary. Good morning, everyone. Welcome to our third quarter 2019 conference call. An updated presentation was posted to our website yesterday afternoon, and we may reference that presentation on our call today. Just as a reminder, our discussion will contain forward-looking statements, a number of actions could cause actual results to differ materially from what we discussed.

You should read our disclosures on forward-looking statements on our news release and in our 10-Q, which will be filed later today, also available is our latest 10-K for the year ended December 31, 2018, all those will have the risk factors associated with our business.

We will begin our prepared remarks with an overview from our CEO, Tom Jorden. And then Joe Albi, our COO, will update you on operations, including production and well costs. EVP of Exploration, John Lambuth, and Cimarex's CFO, Mark Burford, are here to help answer any questions.

As always and so that we can accommodate more of your questions during the hour we have allotted for the call we'd like to ask that you limit yourself to one question and one follow-up. Feel free to get back in the queue if you like.

So with that, I'll turn the call over to Tom.

**Tom Jorden**

Thank you, Karen, and thank you to all for joining us on the call this morning. I will briefly discuss our operational highlights and focus followed by our COO, Joe Albi, who will provide a more detailed breakdown on our quarterly details.

Cimarex had a solid third quarter in a challenging macro environment. Our oil production came in above the midpoint of our guidance range. Total oil grew 8% sequentially with Permian oil growing 6% sequentially. Permian oil growth is projected to continue.

While we plan on continuous sequential growth, occasionally we find that projects are ready to come online sooner than planned. In all cases we bring our wells online as soon as they are ready.

We lowered our capital guidance full-year by $50 million at the mid-point, while keeping our production guidance and well count unchanged, commodity prices continue to be a challenging headwind, particularly for natural gas and natural gas liquid. In spite, of these headwinds, we expect to exit the year without incremental borrowings.

Furthermore, we are pleased to be returning cash to shareholders in the form of our dividend, which we intend to continue to grow over time. We continued to deliver excellent, fully burdened returns. As we have described in the past, we measure ourselves on a fully burdened basis, which includes all drilling completion facilities, midstream land, science, and G&A.

Our well productivity and cost improvements for the past few years have resulted in robust and repeatable investment return. Our current returns are also more resilient to drops in commodity prices than they were five or six years ago. As an example, we have stress tested our total program returns for each of the three prior years, 2016, 2017 and 2018 by modeling all future cash flows as if the flat SEC prices in effect at the end of Q3 lasted forever.

Even with these low prices on a go forward basis, our total program returns are robust. Our investment performance has become repeatable, robust, and better defendable against commodity price swings. With this knowledge and confidence we're doing a better job of planning our future. We also continue to benefit from the tremendous work in science that we've put into understanding resource play development.

Our program was almost entirely development at this point. We still have a surprise or two, but we continue to gain operational confidence in our development in space and decision. We also continue to make a mistake or two along the way. This is the nature of progress. We are laser focused on all elements of our cost structure, capital expenditures and lease operating expenses.

As, we look into 2020 our plan is to generate free cash in a $50 WTI oil, $2.50 NYMEX gas environment. We will remain disciplined, cautious and flexible. We're not burdened by service contracts or undue lease expiration issues and can grow our business at the right pace for the current environment.

Now, I’ll turn it over to Joe to discuss our operations in more detail.

**Joe Albi**

Thank you, Tom. And thank you all for joining our call today. I'll touch on usual items, our third quarter production, our fourth quarter and full-year production guidance and then I'll finish up with a few comments on LOE and service costs.

As far as Q3 production volumes go with continued strong execution, we achieved another nice jump in our production during Q3. Our third quarter posting for net equivalent production came in at a Company record 287,000 BOEs per day, 3% above the top end of our guidance range of 265,000 to 279,000 and up 4% and 31% over Q2 2019 and Q3 2018 respectively.

The guidance beat was driven by continued strong Permian production growth and higher than forecasted NGL recoveries during the quarter

On the oil side, we posted another company record for production. Our Q3 oil volume came in at 89,700 barrels of oil per day, beating the midpoint of our guidance by 1,700 barrels a day and putting us up 8% and 40% over Q2 2019 and Q3 2018 respective postings.

Although we saw quarter to quarter oil production increases in both the Permian and the mid-continent, the Permian drove the increase with our Q3 Permian oil volume at 74,800 barrels a day up 6% over Q2 2019 and 53% over Q3 2018. With the posting the Permian now accounts for 83% of our total company oil production.

Shifting gears to capital and our full year production guidance. As Tom mentioned, through efficiency gains and cost savings, we've lowered our full year 2019 E&D capital guidance to $1.3 billion to $1.4 billion. It's down $50 million or 4% at the midpoint of our previously issued guidance.

That said, we've kept our forecasted full year net completion count at 80 net wells. With our revised completion scheduling, our updated model projects our Q4 net equivalent volume to range from 272,000 to 292,000 BOEs per day, with the midpoint down just slightly from Q3 due primarily to uncertainties we have surrounding the extent of any ethane rejection that may occur during Q4.

On the oil side, we're modeling a range of 86,000 to 92,000 barrels a day with the midpoint virtually flat to Q3 and that's a byproduct of our projected 11.2 net wells coming online during in Q4, comparing to the 21.4 that we had online in Q3 and 39.5 in Q2.

So with our strong execution over the past three quarters, we're increasing our full year guidance ranges for both equivalent and oil production. We bumped our full year net equivalent production guidance to 273,000 to 278,000 BOEs per day. That's up 3% at the midpoint from our guidance last call and with a range of 84,500 to 86,500 barrels of oil per day for full year net oil production. We've raised the midpoint of our guidance, our oil guidance by 500 barrels a day or approximately 1% from the range that we quoted last call.

Jumping to OpEx, we had a strong quarter for our lifting costs, our Q3 posting of $3.34 per equivalent barrel, was down 5% from Q2 and put our year-to-date lifting costs of $3.39 per BOE just slightly above the low end of our full year guidance range that we've quoted last call at $3.30 to $3.65 and represented a drop of 6% from our 2018 average of $3.62 per BOE. With the posting, we've tightened our full year lifting cost guidance to a range of $3.30 to $3.55 per BOE, lowering our midpoint by $0.05 per BOE from the range that we quoted last call.

And lastly some comments on drilling and completion costs. With the slowdown in industry activity, we're seeing cost reductions on both the drilling and completion sides. Current drilling day rates are down 5% to 9% from last call and with service cost reductions and our continued focus on frac design, we've dropped our completion AFEs by 11% to 12% from last call, which translates to a 17% to 19% drop from completion AFEs earlier in this year.

As such, we've realized sizable drops in our projected total well costs during the quarter. In our Wolfcamp program, as an example, cost reductions have dropped our generic Reeves County 2-mile Wolfcamp A AFE to $9.3 million to $11.8 million, again depending on facility design and frac logistics. That range is down $700,000 from our estimate last call, $1.1 million from earlier this year and down $1.6 million from our estimate late last year. Our shallower Wolfcamp A wells in Culberson County are running about $500,000 less than this range with an AFE range of $8.8 million to $11.1 million, efficiency gains that we derived through our multi-well development drilling projects, as we've talked about before put our average development well, total well costs at the low end of these ranges.

And in the Mid-Continent, our refined completion design, improved operating efficiencies and service cost reductions, combined have reduced our AFEs in both our Woodford and our Meramec programs. For example, our current 2-mile Meramec AFE is running $8.5 million to $10 million. That's down $1 million from last call, $1.5 million from earlier this year and $3 million from the cost that we quoted in early 2008.

So as Tom mentioned, we've made tremendous strides in our cost structure, particularly on the total well cost side and it really is showing up in our statistics. Through operation efficiencies, realized cost reductions and by drilling longer laterals, our 2019 Permian program total well cost per lateral foot metric is estimated at $1,150 to $1,200. Now this estimate includes all necessary costs to bring well online, drilling, stimulation, facility and flow-back cost, and it implies a 20% reduction over that same metric that we saw in 2018.

So in closing, we had a great Q3. We executed on the strong production ramp, we promised and forecasted with equivalent and oil production guidance speaks along the way. We've raised the midpoint of both our full year net oil and equivalent production ranges with resulting year-over-year growth of 26% and 24% for net oil and net equivalent volumes respectively.

Our cost structure is strong. Our Q3 lifting cost was down 5% from Q2 and we've lowered the midpoint of our full year guidance by $0.05 per BOE. We've lowered our total well costs significantly with our average Permian total well cost metric in the $1,150 to $1,200 per lateral foot range, down 20% from 2018 levels. We're executing on all cylinders and we're well positioned to deliver on the capital, the activity and production plan that we put in place at the beginning of the year.

So with that, I'll open it up for Q&A.

**Question-and-Answer Session**

**Operator**

We will now begin the question-and-answer session. [Operator Instructions] Our first question comes from Gabe Daoud with Cowen. Please go ahead.

**Gabe Daoud**

Hey, good morning everyone. Appreciate all the prepared remarks and the high level framework on 2020. I guess, wondering if you could just give us a sense on assumed Permian activity levels for the range of oil prices that you give, whether that's in terms of rigs, crews or turn-in-lines. And then I guess, what kind of overall growth do you see for corporate oil production next year?

**Mark Burford**

Yes. Hi, Gabe, this is Mark. Yes. For 2020, we're still working on our plans and we don't have a lot of – we want to give a lot of detail on the plan in the 2020. Recurring eight rigs in the Permian, we have some plans that we'd actually increase from that rig count in the 2020 in our current forecasting the scenarios we're running. And in turn-in-lines with the cycle time for seeing our turn-in-lines have improved with the compressed cycle times. So the different scenarios we're working on at 2020, we are seeing activity, that’s a good pace activity into 2020 and we're focused on that Permian oil growth and we're forecasting growth into 2020.

**Gabe Daoud**

Understood. Thanks Mark. And I guess as a follow-up, I think this year you had some exploration spend in the budget and just I guess as a way to maximize free cash flow next year. Do you think that comes out of the budget and then I guess, if you could maybe even just quantify that number of exploration spend that was in the budget for this year? Thanks guys.

**John Lambuth**

Yes, this is John Lambuth. We did have some exploration spend, but again, it's not that much money in regards to 2019. When we do have a land effort, usually we're very early entrant, thus our entry costs are extremely low. So you really don't even see it within the overall capital framework. So it's not something – and I think one needs to worry too much about in terms of our capital plans for the following year.

**Tom Jorden**

We track that very closely, as a percentage of our total capital. That's a metric, with our focus on fully-burdened returns that we've watched from the inception of Cimarex. We haven't budgeted tremendous amount for exploration. I'm hoping that we're going to find some things that we love and we should have plenty of room there.

**Gabe Daoud**

Great. Thanks Tom. Thanks everyone.

**Operator**

The next question is from Arun Jayaram with J.P. Morgan. Please go ahead.

**Arun Jayaram**

Yes, good morning. Tom, I was wondering if you could comment your thoughts around risk associated with your federal acreage position as we approach an election year. And have you had any conversations with the governor of New Mexico and just general thoughts around that risk of which has been evident since some tweets in early September?

**Operator**

Pardon me. It appears that we may have lost connection with the main speaker line. I'm going to put the call on hold and try and reconnect. One moment please.

Pardon me. This is the conference operator. We have reconnected with the main speaker location and I'm going to join Arun in backend for his question as well. Please go ahead.

**Arun Jayaram**

Tom, can you hear me?

**Tom Jorden**

I can. Thank you.

**Arun Jayaram**

Okay. Did you hear my question on federal acreage, if not, I could restate it?

**Tom Jorden**

Yes. No, we did not. We lost the connection, but can you please restate?

**Arun Jayaram**

Okay, great. Tom, I wanted to get your thoughts on potential risk around Cimarex’s state federal – pardon me, your federal acreage position in the Permian as we approach the election year. Have you had any conversations with the governor or officials in New Mexico and how do you think about that risk on a go-forward basis?

**Tom Jorden**

Well, a lot of questions there, Arun but certainly, Cimarex has been engaged with the governor and such. I have not personally discussed this issue with the governor. Here's how I think about the risk. We're in a primary season and as always in the primary season, some ideas get floated that are a bit extreme. I mean, if you go back four years and watch either the democratic or the Republican debates, I think you'll make that observation. We are certainly exposed to New Mexico. I mean, we've been very forthcoming on that.

We don't think that there is going to be a ban on fracking on federal lands. We are nicely positioned for Texas as well. So even if it were to happen or there to be some discussion around that, we've got plenty of places to adjust and move to. But I'll just close by saying federal royalties are such a huge part of the state of New Mexico's total revenue stream that I cannot imagine a situation where the federal government would close that door on New Mexico. But we will be prepared either way with flexibility in our program.

**Arun Jayaram**

Great. And just my follow-up, Tom, going back to Gabe’s question, Slide 19, you've highlighted different free cash flow yields in a 2020 program from 50 to 60. I was wondering is at the lower end of that band, would you still anticipate growing some oil next year or would that resemble more of a maintenance program based on the initial forecast?

**Tom Jorden**

No. We grow oil under all those scenarios.

**Arun Jayaram**

Great. Thanks a lot, Tom.

**Operator**

The next question is from Neal Dingmann with SunTrust. Please go ahead.

**Neal Dingmann**

Good morning. First question I had was just pertaining to, can you talk about a little bit just on your Delaware plans by county? It looks like most continued to be for 2019 in Culberson. I'm just wondering, I know fully understand you don't have the detailed 2020 out yet. Maybe just talk a little bit about if the area of focus would be relatively similar.

**Tom Jorden**

Well, I would say, it will be relatively similar. We're always going to have a very healthy level of activity in Culberson with our joint development agreement with Chevron. We've a lot of projects we like in Eddy County, lot of projects in Lea County. But Reeves County also has a lot of activity. We're getting after that resolute acreage in addition to the acreage we brought to the table and we're going to be active really across our portfolio.

**Neal Dingmann**

Okay, and then one just follow-up. Thanks Tom. Just look like for 2019, you had about $70 million budget for midstream. Again, knowing for a while you don't have detailed 2020. Just on average do you think the spend for, I would just say non-D&C will continue to be about the same or will that start to trickle down a bit?

**Tom Jorden**

Well, this year anticipated to be 70 or maybe slightly below and then as we move into 2020, our focus is going to be on trying to capitalize on the infrastructure that we have and minimize any midstream associated costs that would be tied to our development programs.

**Neal Dingmann**

Pretty good. Thank you all.

**Operator**

The next question is from Mike Scialla with Stifel. Please go ahead.

The next question is from Mike Scialla with Stifel. Please go ahead

**Mike Scialla**

Hey, good morning everybody and congrats on the quarter. Tom, you said that $50 a case with the 2% free cash flow yield that you still grow oil. I just want to see if you could provide maintenance capital level that you need to spend to keep your oil flat, say with the projected fourth quarter rate?

**Tom Jorden**

Yes, I'm going to bounce pass that to Mark. We – I don't know if we've calculated that fresh.

**Mark Burford**

Yes. Mike, we know we haven't calculated that fresh. We're working on 2020 plan right now, which does anticipate growth in our oil. And we're working in allocation, we're allocating into 2020, as we're currently looking at it, even a greater portion of our capital going to the Permian, but we don't have – I don't have a maintenance capital associated with that. But that yield that we're talking is solely under 2% and nearly 10% is a scenario there. Some of the scenarios that we're working on with these – steady to slightly down, D&C capital. It derives that type of yield and it's basically kind of anticipating budgeting of that 50 and 250 type NYMEX oil and gas price with this – and again as steady slide down capital, holding that flat and running that through the year.

**Mike Scialla**

No problem. Okay. And then the 250 gas price because we're looking at Waha price is still below a dollar. Even with the Gulf Coast Express online. I assume that's what you had mentioned earlier in your prepared remarks, that you're using the kind of the current price is so flat. How does that I guess impact your thinking about your plans for 2020 or does it?

**Tom Jorden**

Well, those NYMEX prices are always, we quote that because that's the index marker, but we bring that back to our actual received price at the wellhead. So we're accounting for all of those basis differentials only in our go-forward plans. Mark, you want to touch on that?

**Mark Burford**

Yes, that's right, Mike. So Mike, we learn different flat cases or even price it – the current forward strip for 2020 is right around 250, I think its 252 last Friday. So it's fairly close to the flat price NYMEX price we're using. But to the extent, we adjust from a – to a flat case from the strip case, we keep it fortunately reduced the realized prices in areas where the local market differentials based on the forward curve of those differential. So we bake – fully bake in all those differential.

**Tom Jorden**

So our cash flow fully incorporates the local pricing for all products.

**Mark Burford**

Yes, for gas and NGL. That's right.

**Mike Scialla**

Thank you.

**Operator**

The next question is from Jeffrey Campbell with Tuohy Brothers. Please go ahead.

**Jeffrey Campbell**

Good morning and congratulations on the quarter. Slide 8 illustrated that the second quarter of 2019 contained half of the entire 2019 timelines. And then activity trailed off in the second half. Since 2020 becomes a year of potentially meaningful free cash generation. I was wondering if you're going to follow us somewhere operational plan as you did in 2019 or would you prefer to make the free cash generation more level-loaded throughout the year?

**Tom Jorden**

Well, I'll start this off and then let Mark comment. Ideally, we would love if it were level-loaded across the platform, but with eight rigs running and these development projects, there is a certain structure to when we bring these wells online. And this is just our business. We are making a good attempt to try to smooth out these field operations to try to have a more even field cadence. But I want to just be clear, our primary goal is to generate outstanding returns on invested capital, stress tests those returns for the downside and make sure that we account for every single cost incurred in bringing that production online.

The production timing is a consequence of good decisions and not a primary driver. Yes, we'd love for this to be smooth and even but the world doesn’t always behave that way with these development projects. Mark, you want to touch on that?

**Mark Burford**

Yes, absolutely, Tom. Just echo what you're saying and the fact that the number of wells brought on into production in any particular quarter can be varied by size of pads we’re drilling in a different development. The pace of development that we're drilling for wells, I don't see completed per quarter is much more consistent. And our operational cadence is what we are focused on is operational cadence of our activities in drilling or completing our laterals and drilling our wells.

And then the timing of these well productivity that we brought on, bring any quarter will be vary depending on, again, the size of the pad. The areas that we're drilling and even can vary somewhat that the working interest that we have in the areas we're bringing on since this is a net well completion per quarter. We are definitely focused on our operational cadence and our well lateral feet drilled per quarter and again, the quarterly production cadence of wells brought online can be more - look more erratic than what the underlying operations represent.

**Tom Jorden**

Yes. And I want to make one other comment. We're focused on costs. I said in my opening remarks, that is a laser focus of ours. And to smooth out that could be done, but it could involve significant costs, mobilization costs, getting enough water on pad as you need it.

And so there are a lot of other considerations but we are – that sound like a broken record here. We are driven by returns on invested capital. Joe, you want to comment on that?

**Joe Albi**

Yes, I do. I wanted to use this year as an example of this completion cadence that both Mark and Tom were talking about. If you look back over the year and I'm going to talk about multi-well projects in the Permian. In Q2, we had two multi-well projects on a gross basis and there only were two wells per project and that was four net wells – four total gross wells for the quarter. In Q2, we had six multi-well projects that range anywhere from two to seven wells per project and on the average, there were five wells for every one of those projects.

So in Q2, these six projects brought on 30 wells, in Q3 five projects brought on 21 wells. And as we go into Q4, two of these projects are bringing on 12 wells. As I mentioned in my opening statements, that's really the byproduct of our flat oil production here in Q4. So we're always going to have some semblance of that completion cadence and our production growth.

**Jeffrey Campbell**

I really appreciate the color and I think your points are fair and then probably what we should end up doing is thing you have free cash on an annualized basis rather than getting to hung up on sequential. But I thought it was fair question to ask.

**Tom Jorden**

It’s a totally fair question. And we look at this, I was on a call early this morning on just this topic. And I was convinced that by spreading it out further, we get better returns and lower cost structure so that it's a really fair question. We welcome the question. But some of this is just details that ironing a program out, sometimes the chips fall in a non-ideal way. I'll just leave it there.

**Jeffrey Campbell**

Okay. As my follow-up on Slide 28, it references Cimarex’s two gas gathering systems and Slide 29 illustrates the water management system. I was just wondering, is the longer term view to keep these assets in-house for cost control since you guys mentioned, you're very focused on costs or could you sell them and still have an advantaged cost structure.

**Tom Jorden**

That's a very pertinent question to us because as we've discussed in prior calls, this is something that is an active subject of investigation. We've done a lot of work over the last quarter on this. We certainly have a very valuable gas gathering system and a very valuable water gathering system. I will tell you that we have and continue to explore monetization options, but it really is a trade-off between a quick hit of cash when you monetize versus the longer term increased operating expenses.

If I were surprised by anything, even at today's multiples, it's not an obvious decision. You can sell them, take the cash now, which you're going to pay for it in perpetuity with higher operating costs. We think we've got one of the lowest cost structures around. We realized that that cost structure is a real asset of ours. Gathering system, both for gas and water provides us tremendous operational flexibility.

So although, we continue to explore that, we have conversations on this every day. I will say that for now, we have not made a commitment to monetize these assets. It's an active argument at Cimarex. It's a healthy argument. But it's pay me now or pay me later type choice.

**Jeffrey Campbell**

Okay, great. I appreciate that color. And again, congratulations on the quarter.

**Tom Jorden**

Thank you.

**Operator**

The next question is from Noel Parks with Coker Palmer. Please go ahead.

**Noel Parks**

Good morning. I just had a couple of questions. Thinking about Culberson County and the economics out there, also thinking about gas and NGL issues that the whole industry has had. How sensitive do you consider the Culberson County economics to sort of the uncertainty around the takeaway and processing part of the equation? Just sort of thinking, there's that piece of – and of course, the demand piece for the products that also it fluctuate for a while with NGL.

**Tom Jorden**

Well, we don't see uncertainty in takeaway of processing. We've got that system with multiple outlets for takeaway. We have multiple outlets for processing. And I'll let Joe comment on this, but our operations and marketing group had done a tremendous job when we've had occasional interruptions with our processors or gatherers, transporters. We've been able to very adeptly redirect that flow because we do control that asset from a gathering standpoint and we have multiple outlets.

Oil is the dominant phase, dominant revenue phase of Culberson County. I wish gas and NGLs were stronger revenue component, but even at current pricing with this hostile price environment, the economics of Culberson County are supremely attractive to us. And, we just see upside to pricing. If, we can make the kind of returns we're making now, it's just only going to get better if we see any kind of recovery in gas and NGL pricing.

I mean, those economics – I appreciate your question because I think the economics of Culberson County are under appreciated. Not only is Culberson County as we demonstrate in our slide, one of the premier counties for cumulative oil production, but we deliver that oil at a basin wide low operating costs because of the nature of that reservoir and the low operating cost of our system. So we're pretty pleased with that asset.

Joe, you want to comment on that?

**Joe Albi**

As far as takeaway goes, Tom hit it right on the head as far as the value to the infrastructure kind of leads into the prior question. A Triple Crown is an example we have a large system for gas gathering, which can offload to four or five different processors at any point in time.

We see adequate processing capacity in the Delaware to handle not only our gas but majority of the basins gas in the near term. As far as NGL takeaways concern, we're linking our sales to those owners of the production facilities who have pipe out of the basin.

On the oil side, we're doing the same thing. 85% of our oils on pipe or we're signed to purchasers who can get us out of the basin. And on the gas side, as we've talked about the residue gas side, we've secured sales of gas, our gas through 2020 a 100% through the first quarter, which is committed to be sold and we've got 75% on the average over the remainder of 2020 that's committed to purchasers. All the while we secured a takeaway on WhiteWater to get to WAHA. And also I think in our earnings presentation you'll see that we've committed to Whistler. So we're, long-term thinking and it's all about getting that base and getting that product out of basin.

**Noel Parks**

Great. Thanks. And my other question, I was just curious have you seen any significant change in the leasing environment in the Woodford Meramec over the past few months or so?

**John Lambuth**

This is John. Well certainly there's a lot less activity within the whole stack play and then yes, I think it's fair to say not as much in terms of competition if one's looking for that incremental acreage. So yes, thanks, that slowed down definitely in that pace current day.

**Tom Jorden**

One change I've observed is because so many of our competitors are tasked with living within their cash flow. There are a lot of operators that are looking to sell non-operated interest, a number of operators because they're sticking to that discipline of living within interest, a number of operators because they're sticking to that discipline of living within their cash flow, find that they only have the cash flow to participate in their own operator properties.

So, we've had some pretty good opportunities in the Anadarko and in the Delaware basin to pick up additional interest in some of our projects at costs that quite frankly we haven't seen in years.

**Noel Parks**

Terrific. And just to clarify, are those things that are people actively approaching you or you're just aware as you see people going on consent that there might be an issue?

**John Lambuth**

It runs the gamut. Mainly it's just they make it aware that they are looking to get out of the wells if we're operating at something that we make an offer. Sometimes it is at poolings where we get it through the pooling. It varies but as Tom alluded to, there is quite a few operators who to stay within that budget, they are getting out from a non-op perspective. So we've gone very well in picking out some of the additional interests.

**Tom Jorden**

As an interesting aside and a statement of how free markets function, private equity has come out of the woodwork on this subject. Private equity is highly attuned to this opportunity and the number of private equity players are actively soliciting relationships where they will pick up this non-operated interest if operators don't want to participate. So there's a little market that's developing for this. But it's, it's a change in our business. We wouldn't have seen this a few years ago.

**Noel Parks**

Great. Thanks a lot.

**Operator**

The next question is from Drew Venker with Morgan Stanley. Please go ahead.

**Drew Venker**

Good morning. Tom, you've talked a lot about maximizing NPV and rates return and clearly as you talked about 2020, free cash flow is another important aspect. Can you talk about how spacing might play into your optimization of returns versus NPV in the current commodity price backdrop as you said, it's kind of harsh at this point. But I think especially given that you have probably as good of an understanding of spacing and downhole well geometries as anybody.

**Tom Jorden**

Well, I appreciate that question Drew. We've talked about this at length and we love talking about it because we live it every day. We see the spacing decision as a trade-off and a natural interplay between rate of return and net present value. And we have these discussions every day. In fact, I had a discussion this morning on a spacing project where we made it clear to one another and to our operating group that we will not spend money to bring on non-economic production.

At least I'll say we won't do it on purpose. And so studying these projects and understanding where your break over point is and when you should stop down spacing is really an important element. So we seek to not be wasteful by having our wells too coarsely spaced and we seek to not be wasteful by having our wells too tightly spaced. And they are a waste of both sides of that. It's not a one size fits all. It changes from area to area. It changes from reservoir to reservoir. And I'll just say I've tremendous confidence in our team in our approach in understanding the science behind this.

John leads that effort and as I said in my opening remarks, we make mistakes. We're not perfect on this subject and yet I really am confident in saying that we are continuously getting better. You want to comment on this, John?

**John Lambuth**

Well, just as a follow up, I would emphasize what Tom said, not one size fits all. We definitely see variations in our spacing thoughts, even within the Wolfcamp as we fill across our acreage from Culberson to Reeves to Lea and on it. And, there's so many dynamics in there, but we have a very good understanding of it that we're able to adjust on a section level basis to come up with the proper spacing. So, I feel very good about what we'll be able to do in 2020, in terms of development projects we currently have planned and the appropriate spacing for it

**Drew Venker**

Thanks for the detail was just thinking just as a follow-up to that, if you're using 2019 as a starting point and point of comparison, if you're, if we end-up being at the lower end of this $50 to $60 price range you laid out for 2020 does that generally bias you towards wider spacing? And then conversely, if we're at 60 tighter spacing?

**Tom Jorden**

We've run those models and we've looked at not only commodity pricing but also net revenue interest and I will say that our experience is that the boundary on over spacing can be so punitive that it's not really going to change within the price file that you just quoted that I would not see us at a $60 or even $70 oil price making different spacing decisions.

**Drew Venker**

Thanks Tom.

**Operator**

The next question is from Betty Jiang with Credit Suisse. Please go ahead.

**Betty Jiang**

Good morning. I have two questions on cost. First on CapEx. There has just been tremendous progress this year cutting the Permian well cost by a 20% year-on-year. Just wanting to understand are there additional levers to move that 1,150 to 1,200 per foot cost even lower as we look out to 2020. And are there any of that being reflected in the preliminary free cash flow outlook?

**Joe Albi**

Hi, Betty, this is Joe. We're constantly looking at how we can become more and more efficient. A lot of the recent drop that we've seen has come as a result of service cost reductions on the completion side. We're pushing hard to optimize efficiencies and combine some of our midstream efforts and contractors into laying the flow lines for our wells to the midstream systems. As an example, we're looking at our battery design so that we could produce more wells into a battery and potentially apply a drill to fill type of strategy to optimize our completion costs.

So it's hard for me to give you, hey we can reduce it by X, but I will tell you that it is a strong emphasis around his company right now that costs are relevant in this price environment and in order for us to really be a top performer. So it's our focus.

**Mark Burford**

Yes, Betty as far as it being forecasted into 2020 our typical practice is to kind of use the current AFE that we have in hand, kind of our current cost structure and not to make assumptions on better – further improvements from there even though there's potential for that.

**Tom Jorden**

Let me join the chorus here. We want to fairly and transparently report our costs. We think the focus on cost for lateral foot is a good focus. That said Cimarex operates over a fairly wide geographic range within the basin and our costs will vary significantly across the basin. We have some development projects in Culberson County that all in are below $1,000 a foot. And we're averaging that with some projects in the deep basin where you have a little more pressure and a little more drilling and completion challenges that that average that number up.

We also have some one mile wells in our portfolio, although on average we're certainly going to longer and longer laterals as shown in our deck. But I don't want to discourage our teams from bringing forward one mile projects that have outstanding returns. And so, you know, we're going to continue to report a transparent average, but within that average there's a lot of structure.

**Betty Jiang**

Got it. Now, that's really helpful color. Thank you for that. And then similarly on the other costs item LOEs ease, I mean historically oilier production growth typically put upward pressure on cost, but that has not been the case for you guys this year, going forward how should we expect LOE to evolve as your growing oil production in the Permian by seeing declining gas production out of Mid-Con? So do you think there is a bit more room on the LOE to come down on the per unit basis?

**Joe Albi**

This is Joe again. This quarter we saw a nice reduction in our overall absolute LOE. I even with the resolute assets, coming on board tail end of Q1 we were down on the LOE side, but our work over expense was up and that's a result of converting to live. So there's a lot of wells to live. So, there's a lot of variables in that number because they've got the day to day LOE costs to operate the wells and then you've got the work over expenses that slide into that category as well.

Our focus is going to remain on the same items we are now, the bigger emphasis is going to be on SWD or salt water disposal. That's where the majority of our cost reductions have been achieved and it's we're going forward. We're going to be able to take advantage of them.

That's where that infrastructure that keeps popping its head up comes into play. The optionality and the cost optimization of the systems provide us, allow us to swing water to use for our fracs. And at the same time we're using that water for a fracs we're not having to incur in and kind of electrical charges to the SWD wells to dispose it and although that sounds like a small item that can add up, so that's where those efficiencies have been coming from and that's where our focus is going to be going forward.

**Tom Jorden**

Yes. Betty, I'll just add on, we kind of highlight some are Culberson County, lease operating expense per barrel. In that County we're close to $2 a barrel on production spend. In the total Permian we're only about $3.50, in this quarter reported $3.34 cents per barrel on our production expense per barrel equivalent. As we look into 2020 a blending of the Permian Anadarko, we still expect to have a very competitive cost structure even with the Permian growing more rapidly.

**Betty Jiang**

Got it. Now this is really helpful.

**Operator**

The next question is from Brian Downey with Citi Group. Please go ahead.

**Brian Downey**

Good morning. Thanks for taking the question. Just a quick one for me. I believe you had recently tried an e-frac completion, just wanted to confirm that that was correct. And any color you could provide on cost-saving uptime versus conventional or stage efficiencies, I realized that maybe a small sample size of any – curious on any comments and if you have future plans to continue using them when available.

**Tom Jorden**

Yes, we did just finish one trial completion on two wells and we have not finalized all the costs associated with it. So we're – early for me to tell you the efficiencies that we may or may not have achieved with that operation. But we tried it because we want to learn more and we are working with our main service provider to see how we may be able to better utilize the infrastructure and the electrical infrastructure that we have in particular in Triple Crown in the near to distant future. Transition ourselves into that realm, not only for cost savings but also from an emission standpoint. We see tremendous benefit to cut in any kind of emissions that would be associated with fracs

**Brian Downey**

Now. So does that mean you're using the electric infrastructure within the field or are you still using the field gas or I guess what would be the plan going forward?

**Tom Jorden**

In this case the frac that we tried was using fuel source not coming from our transmission lines a CMG, but going forward, what we're really seeing that the true economic benefit where, where we see at the end is being able to provide our own power off our own grid and that could substantially, we believe lower the cost to do the new frac.

**John Lambuth**

We own our own electrical distribution systems at Culberson County and in our Reeves County and like many others have used that's probably where electrification will ultimately go rather than towing a power plant around the oil field, it probably makes more sense to have a power source that’s stationary and just equipment that's mobile. We're studying this problem hard. We have a team digging into it. We're looking for some long range solutions and like so many things that we study hard, they look a lot simpler to us. The less we know about it. And as we learn more and more it becomes more complex. But we're convinced that this is a long-term direction that we want to go in and we're hard at work just understanding the problem.

**Brian Downey**

That's helpful. I appreciate the color. Thanks everyone.

**Operator**

The next question is from Nitin Kumar with Wells Fargo. Please go ahead.

**Nitin Kumar**

Good morning and thank you for taking my question. Just a quick one. I was looking at the Reeves County acreage in your latest presentation on Slide 12, it seems to be a slight drop of about 13,000 acres. Could you help us understand what happened there?

**Tom Jorden**

Yes. if you look at our Reeves County map, there's some acreage in the far south of the County that was an exploration play that we embarked upon a few years ago. It's actually off the map on slide 12. We don't carry any locations on that acre currently, we never have. And some of it was due to expire and we let it expire. We just couldn't make economic wells there. You want to add to that, John?

**John Lambuth**

We couldn't make a payment.

**Nitin Kumar**

So suffice it to say it didn't meet the cost threshold. I guess a broader question Tom, in the past you've talked about the optionality and kind of having two basins, as I look at the initial guidance, clearly you're favoring the Permian and I get it why, but how far is the Mid-Con today for competing within your capital program?

**Tom Jorden**

Well, there we could easily put 30% or more of our capital in the Mid-Con next year and that would be opportunities that compete heads up. We have a lot of things in the Midcontinent that are competitive in today's environment. That said, as we've discussed in the past, we are in a, let's pull back and see what we can accomplish from an asset growth standpoint in the Midcontinent. John and his team are hard at work looking for new areas and new landing zones and we'd like to just beef-up that asset and have it compete longer term. Do you want to comment on that, John?

**John Lambuth**

The only thing I'd add is it is just what we're looking for is more depth to that inventory. So there's more sustainability to it. So we're putting a lot of effort to not just looking across our existing acres positions that we have. And then furthermore, looking beyond that because as someone said earlier in a call there are opportunities now and we're just looking for where are those opportunities where we think we have maybe an advantage to get at and maybe at a reasonable and bring forth things that would compete for capital. So that's kind of where we're at right now with the Anadarko base.

**Nitin Kumar**

Thank you. Gentlemen.

**Operator**

This concludes our question-and-answer session. I would like to turn the conference back over to Tom Jorden for any closing remarks.

**Tom Jorden**

Yes, I want to thank everybody for participating. Also, thank you for your patience with our telephone interruption. We've had a lot of great questions and I appreciate the thoughtful probing. We're looking forward to executing on what we've laid out today and updating you with our progress on future calls. So thank you again.

**Operator**

The conference is now concluded. Thank you for attending today's presentation. You may now disconnect.