THIRD QUARTER 2016 EARNINGS REVIEW REMARKS

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[Zach Dailey]

Welcome to Marathon Oil Corporation's third quarter 2016 earnings review. The synchronized slides that accompany this review can be found on our website, at MarathonOil.com. Additionally, we'll conduct a live question and answer webcast on Thursday, November 3rd, at 8am Central Time.

Slide 2 contains a discussion of forward-looking statements and other information included in this presentation. Our review will contain forward-looking statements subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied by such statements. Please read our disclosures in our SEC filings for additional discussion of these items.

Reconciliations of the non-GAAP financial measures we discuss can be found in the quarterly information package on our website.

Participating on this webcast are Lee Tillman, President and CEO and Mitch Little, Executive Vice President, Operations. With that, I'll turn the presentation over to Lee who will begin on slide 3.

[Lee Tillman]

Thanks Zach. I'd like to begin on slide 3 with a high level update on our investment case.

We have used this stair step graphic to illustrate our playbook for success—and we continue to execute with these objectives in mind. Beginning with the foundation, we've taken action to strengthen our balance sheet, and at the end of the third quarter we had $5.3 billion of liquidity, including $2 billion of cash. We've focused relentlessly on reducing our cost structure, and continue to put downward pressure on production costs, G&A costs, and capital costs across all parts of our business. And finally, we've made material progress toward concentrating and simplifying our portfolio to the U.S. resource plays while maintaining our peer leading leverage to oil. This summer, we added a large bolt-on acquisition to our already extensive STACK position, and since August of last year we've delivered $1.5 billion of non-core, conventional asset sales.

All of these actions have us well positioned to achieve profitable growth within cash flow at moderately higher oil prices. While our planning process is still underway, our preliminary five-year view for resource play production supports a compound annual growth rate of 15 to 20 percent within cash flows at flat $55 WTI.

We delivered strong execution across our entire business and have singled out a few of the highlights on slide 4. Importantly, we achieved cash flow neutrality in the third quarter, with operating cash flow covering capital expenditures and the dividend, at an average WTI price of about $45/barrel.

On the operations front, production for the company was above the top end of guidance and up sequentially. The Oklahoma Resource Basins were up over 50 percent from the prior quarter, with that team benefitting from new wells to sales and a couple months of contribution from our recent STACK acquisition. We continue to balance leasehold demands and acreage delineation in the STACK, and brought some outstanding Meramec oil and volatile oil wells to sales that are, on average, exceeding type curves on both our legacy and acquired acreage.

Our Bakken team delivered the best industry Bakken Three Forks well in the past three years on our East Myrmidon acreage. The Eagle Ford asset continued their trend of continuous improvement in completed well costs, with this quarter's wells averaging just under $4 million. Internationally, we had an excellent quarter with Equatorial Guinea achieving their highest quarterly production since 2013 following the successful start-up of the Alba B3 compression platform in July. That contributed to a 10 percent sequential increase in their quarterly production volumes.

On the portfolio side, earlier this week we closed on the sale of select non-operated waterflood and CO_2 assets in West Texas and New Mexico for proceeds of $235 million, before closing adjustments, bringing our total for non-core asset sales to over $1.5 billion since August of last year. You should expect portfolio management to continue as we drive to maximize capital allocation to our lowest cost, highest margin opportunities.

Turning to slide 5, you can see that third quarter total company production was 9 percent above second quarter levels on a divestiture-adjusted basis. Third quarter North America E&P production was just above the high end of our guidance, while International E&P was at the midpoint of guidance.

Third quarter production from the resource plays increased 2 percent from the prior quarter, with growth in Oklahoma and Bakken offsetting planned declines in the Eagle Ford.

Quarterly Oil Sands Mining production available for sale was an all-time record: 58,000 net barrels per day. This was 45 percent above Q2 which was impacted by the wildfires and planned turnaround, and well ahead of guidance due to successful reliability initiatives that reduced unplanned downtime and increased volumes.

For full year E&P guidance, we have both narrowed the range and raised the mid-point.

Slide 6 illustrates our quarterly trend in capex over 2016. Third quarter capex was just below $250 million for the company, with 85 percent directed to the U.S. resource plays. We anticipate an increase in fourth quarter spend, that's predominantly driven by our increase in resource play rig count by year-end: from four to five rigs in Oklahoma; from four to six rigs in the Eagle Ford, and from no rig activity to one rig in the Bakken. This increase sets the stage for us to resume quarterly sequential growth in the resource plays in the second half of 2017 and we expect to accommodate this step up in 4Q activity well within our full year budget of $1.3 billion.

Slide 7 shows our total company cash flow for the quarter and our ending cash balance. Operating cash flow before working capital essentially covered our capital expenditures and our dividend for the quarter with WTI averaging just about $45/barrel. Keep in mind that our $113 million deep-water rig termination payment was made in Q3, and without that one-time item, we would've been comfortably cash flow positive.

Even after paying cash for our STACK acquisition, we ended the quarter with nearly $2 billion of cash on the balance sheet and an untapped $3.3 billion revolver. With that brief summary, I'd like to hand it over to Mitch to review our operations in more detail.

[Mitch Little]

Thank you Lee. For starters, I would like to give a shout out to our teams across the company who delivered a very strong operational quarter. They hit on all cylinders, delivered exceptional well results, maintained high operational availability, and did it with the best year to date safety performance we've achieved as an independent E&P. Before I dive into the specific assets, I'd like to spend a moment on slide 8 discussing cost reductions, which remains one of the most important parts of our business today, and an area where we continue to make great progress.

In the third quarter, we reduced absolute production costs in North America by $66 million, or 37 percent, from the year ago quarter. On a unit cost basis, production expense averaged $5.70 per BOE, down 23 percent from the year ago quarter. These improvements reflect both commercial savings as well as ongoing efficiency gains, many of which are structural in nature and will be durable across a range of commodity prices.

Next I'll move to an overview of third quarter operational activity by basin beginning on slide 9 with Oklahoma where we have seamlessly integrated our newly acquired acreage, and are executing on our strategic objectives of protecting leasehold and delineating our position while advancing completion designs and delivering extremely competitive well results.

Quarterly production in the Oklahoma Resource Basins was 41,000 BOE per day, up more than 50 percent from second quarter levels due to the addition of acquired volumes for two months, more wells to sales, and exceptional well results.

I'd like to draw your attention to the cumulative production plot in the bottom left corner of the slide, which highlights the performance of this quarter's Marjorie and Lloyd wells. Both wells are 7,700 foot laterals and are producing 70 percent oil with about 60 days online. Impressively, they're trending between 45 and 110 percent above our type curve, despite being nearly 25 percent shorter laterals. We completed these wells with 2,900 pounds of proppant per lateral foot on 175 foot stage spacing, while utilizing diversion. The wells are located in Eastern Blaine County near our second quarter Olive June and Irven John wells, which are also plotted on this chart. As you can see, both of those wells continue to perform strongly with more time online.

As Lee mentioned, we'll be increasing our rig count in the fourth quarter, which means an additional rig added to our STACK acreage in Oklahoma to be focused initially in Kingfisher County. In fact, our fifth rig will spud its first well this week.

We expect six to seven STACK Meramec wells to sales in the fourth quarter across our consolidated STACK position.

On slide 10, we've plotted the average of the six standard lateral length Meramec oil wells we brought to sales in the quarter. As we'd expect, especially during the leasehold and delineation phase, we are seeing some variability in well results, but in aggregate, they're performing about 30 percent above type curve with over 30 days online.

Our Oklahoma team continues to progress on the technology and innovation front. We're now on version 3.0 of a multi-variant analysis, or MVA model, which includes the statistics from our reservoir quality index and stimulation modeling that we're regularly using to guide our selection of landing target and stimulation parameters. This proprietary MVA model continues to show promise, and certainly contributed to the success of our recent volatile oil wells in Blaine County.

Our first operated Meramec infill pilot will TD in the fourth quarter in Kingfisher County. We've shown a cross section at the bottom of this slide, and you can see that we're testing the development of six standard lateral wells on staggered 106-acre spacing: two new wells in the Upper Meramec offsetting an existing producer and three wells in the Lower Meramec. Results from this pilot are expected at the end of the first quarter. This infill trial reflects our base assumption of six wells in the Meramec, per drilling spacing unit.

We also expect results from two non-operated Meramec infill tests in the coming months. One of the pilots is in the volatile oil window, and will be testing eight wells per section, with four wells in the upper Meramec along with four wells in the lower Meramec; the second pilot includes three wells in the Upper Meramec and three wells in the lower Meramec and will be testing spacing density equivalent to 10 wells per section.

On slide 11, we're highlighting all 12 company-operated wells we brought to sales in the third quarter in the STACK and SCOOP with blue callout boxes. Eleven of the twelve were lease retention wells, and that remains a near term priority in Oklahoma, especially in the STACK where we'll need about 3 rigs to protect term lease for another couple years. In the SCOOP, we'll be about 95 percent HBP by year-end.

The two volatile oil wells I mentioned earlier are in the top left call out and were completed near the Blaine / Kingfisher County line. The success of these wells, along with the continued outperformance of our second quarter wells in the same area give us further confidence in the repeatability in this part of the play.

We also note the location of outside operated activity in the gray boxes, including the two infill pilots I previously referenced, as well as the location of our Operated Yost infill pilot.

Turning to Eagle Ford on slide 12. Third quarter production of 97,000 BOE per day was down sequentially, as anticipated, due to the base decline and running at activity below maintenance levels. We'll be increasing activity in the fourth quarter, taking the rig count up from four to six, and we anticipate seeing the production profile flatten sequentially as a result.

In the third quarter, two thirds of our wells were in the oil window where we tested various completion designs. We increased our average proppant per lateral foot by over 65 percent to 1,800 pounds per foot. Going forward, our standard, conventional design in the oil window is 2,000 pounds per foot proppant loading. Additionally, we increased the number of stages per well from 22 to 27, and did it all while reducing completed well costs to below $4 million. Early performance from the Q3 program is in line with expectations, and 200 foot stage spacing in oil wells continues to show 15 to 20 percent uplift compared to 250 foot stage spaced wells through the first 90 days. We are seeing the percentage uplift moderate further out in time, but initial production uplift is clearly enhancing the economic returns from these wells.

On the drilling side, as we approach technical limit drilling rates, we continue to innovate and have an intentional focus on minimizing flat time, where we've integrated new methodologies that include offline cementing, large multi-well pads, more efficient walking packages, and speedheads. All of these efficiencies are durable, and will continue to benefit us in the future.

The Eagle Ford team continues to progress their technical work and field development optimization, striking the right balance between resource capture, well spacing, and DSU value in the current price environment. Our Eagle Ford asset has optionality: it's a substantial operated business, we've proven its growth potential, we have significant depth of remaining high return investment opportunities and we have the potential to either resume growth in the future, or operate the asset to provide a stable production base while generating significant free cash flow to fund growth in other areas.

As you flip to the next slide, I'll discuss some of our individual well results from the third quarter.

Slide 13 shows all 36 wells we brought to sales in the quarter, two thirds of which are in the oil window and represented in the dark blue boxes. Almost all of these were Upper Eagle Ford / Lower Eagle Ford co-development concepts.

As I previously mentioned, performance from our Q3 wells was strong, with our new completion designs delivering some of our highest 30 day IPs. In fact, the unbounded Hausmann 1-H delivered our best 30 day IP ever, with nearly 2,300 BOE per day and an 81 percent oil cut. The team continues to optimize completion design, and is using an "engineered approach" varying stage spacing, proppant loading, diversion techniques, as well as fluid volume and pump rates while taking into account local variations in geology, reservoir properties, and a variety of other factors. We are still in the early days of engineered completion trials, but are seeing encouraging results thus far, and will continue to employ these techniques during the fourth quarter.

On slide 14, I'll transition to the Bakken, where production was 54,000 BOE per day, up slightly from the second quarter despite only three gross operated wells to sales. We benefitted from the three well Maggie pad with combined IP30 rates of over 6,900 BOE per day, continued outperformance from our second quarter wells, and high operational availability across our base business. The three wells on the Maggie pad brought online in Q3 were in our East Myrmidon acreage. We landed two of the three wells in the first bench of the Three Forks, and they had two of the best 30 day IP rates in the entire basin over the last three-plus years. Average completed well costs for these wells was $5.9 million including the significantly higher intensity completion designs.

In the bottom left chart, you can see the meaningful improvement in well productivity we've had in 2016, and even in 2015, from historical levels. A big factor behind this positive move has been a step change in our completion design, which I'll discuss in a bit more detail on the next slide.

Production expense continues to move in the right direction, down roughly 20 percent on a unit basis from the third quarter of 2015, as we achieved our first full quarter utilization of our water gathering systems in the Hector and Myrmidon areas, with about 70 percent of our water production now on the system. As Lee mentioned earlier, we'll be resuming drilling operations in the Bakken with the addition of a rig near the end of the year to begin building momentum as we enter 2017.

On the next slide, I'll discuss the individual well results in a bit more detail.

On slide 15, you'll see a map of our Myrmidon position – both on the east and west sides of the river in Mountrail and McKenzie counties. The Maggie Pad is located in East Myrmidon.

In the top left chart, you can see cumulative production from the three Maggie pad wells. All three have trended well above type curve in the first 30 to 60 days. We completed all three of these wells with a stimulation design that is a sizable shift relative to our 2015, and early 2016 recipe, with great success. We pumped between six and 15 million pounds of proppant, 45 to 50 frac stages, and used diversion on all wells. Additionally, all three wells were plug 'n perf, where we have begun seeing a noticeable uplift compared to sliding sleeve completion techniques. As we move forward, we will continue to perform optimization trials, but see our base design being similar to the techniques employed on the Maggie Pad.

Equally important is the sustained, outstanding performance from our second quarter wells on our Clarks Creek pad in West Myrmidon, shown in the bottom left chart. Those four wells have produced, in aggregate, over 800,000 BOEs in just over 100 days. And importantly, as is the case with all of our Bakken production approximately 80 percent of this volume is oil.

On Slide 16, we're illustrating how our recent wells compare to Bakken industry activity. It is clear that with our step change in completion designs, in addition to the favorable geology in the Myrmidon area, we are delivering wells that compete very favorably against our peers.

Looking at the graph in the upper left hand part of the slide, we show the top 15, 30 day IP rates from all Middle Bakken wells put on line between 2013 and mid-2016 – over 3,000 in total. The top two wells are from our Clark's Creek pad, and our Maggie well in East Myrmidon also makes the top 15.

Moving to the lower left hand section of the slide, you see equally compelling results from our Three Forks completions. In this case, the best 30 day Three Forks rate in the basin is Marathon's Rufus well at 2,635 BOE per day, brought on line in Q3. Perhaps even more impressive, is that four of the top ten wells (out of over 2,000), were from Marathon's Clark's Creek and Maggie Pads in 2016.

The Bakken asset team has brought a renewed focus on being best in basin. We've done a lot of work on all fronts over this down cycle toward achieving that goal, and believe that based on our competitor analysis from joint interest activities, we have positioned ourselves very favorably, including being the lowest cost operator. With the recent increased well performance, we also expect to compete with the best on capital efficiency and returns.

Our third quarter results in East Myrmidon are an excellent extension to our high quality area in West Myrmidon. While no wells to sales are planned for the fourth quarter, we're looking forward to bringing back a rig next month and begin positioning for an exciting 2017.

On slide 17, I'll transition to our International E&P segment, where we also delivered a very strong third quarter, producing 128,000 BOE per day, up seven percent from the second quarter. We accomplished this while reducing unit production costs, excluding Libya, by 24 percent from Q2 and 46 percent from the third quarter of 2015.

The quarterly production increase was driven by exceptional performance from EG. After the successful start-up of our Alba B3 compression project in July, we achieved production levels not seen since 2013. Through the first 100 days, the new compression facility has performed extremely well with an operational availability above 95 percent, which would certainly place it in the upper quartile of operating performance for new projects with similar complexity and scale. As we've mentioned before, our conventional assets, anchored by EG, will generate cash that we can redeploy into the higher return opportunities we have in the U.S. resource plays. Beyond the cash received from the sale of primary products from the Alba field during the quarter, we generated nearly $100 million of EBITDA from our equity share of the three onshore plants.

Although early days, we are encouraged by the recent lifting of Force Majeure in Libya as production resumed at our Waha concessions in October, and gross daily volumes ranged between 30,000 and 50,000 barrels of oil per day during most of the month.

As we look to 2017, we expect meaningfully lower capex requirements across our conventional businesses, which allows us for increased free cash flow generation at forward strip pricing and cash which can be directed toward increased activity in our North America resource plays.

I'll touch briefly on our Oil Sands Mining segment on slide 18 before turning back to Lee for wrap up. OSM produced a record 58,000 barrels of synthetic crude oil per day in the third quarter, up 45 percent from the second quarter when the asset experienced downtime from the impact of wildfires and a planned turnaround. During the third quarter, both mines ran extremely well, and far exceeded guidance.

Third quarter operating expense, before royalties, was $21 per synthetic barrel, representing the lowest unit cost performance in the history of the mine.

Production guidance for the fourth quarter will be lower than third quarter due to planned maintenance.

With that brief overview, I'd like to turn it back to Lee for final comments.

[Lee Tillman]

Thanks Mitch, I'll wrap up on slide 19.

Our key takeaways today are—excellent well results and strong execution in the third quarter while living within our means; increasing rig activity in the fourth quarter within our original budget to prepare for sequential growth in the second half of 2017; and line of sight on 15 to 20 percent resource play CAGR at flat $55 WTI.

With $1.5 billion of non-core asset sales announced or closed since August 2015 and our recent STACK acquisition, our commitment to portfolio management is clear. This will position us, along with a strong balance sheet, outstanding operational execution, and a very competitive cost structure, to drive profitable growth within cash flow at prices not far removed from the current strip.

We demonstrated our ability to deliver enterprise-wide cash flow neutrality this quarter at $45 WTI, and have positioned ourselves for execution momentum in 2017 as we begin increasing activity in the fourth quarter.

Our playbook has not changed. It reflects our consistent view of the macro environment for 2016—transitional, volatile – but still with opportunities. And looking forward, a strengthening price view as we move later into 2017.

That concludes our prepared remarks and we look forward to your questions during the live webcast tomorrow morning. Thank you.