FOURTH QUARTER & FULL YEAR 2015 EARNINGS REVIEW REMARKS

Zach Dailey

Director Investor Relations

February 17, 2016

[Zach Dailey]

Welcome to Marathon Oil Corporation's fourth quarter and full-year 2015 earnings review. The synchronized slides that accompany this review can be found on our website, at MarathonOil.com. Additionally, we'll conduct a live webcast on Thursday, February 18, at 8 am Central Time / 9 am Eastern Time. The live webcast will begin with prepared remarks discussing our 2016 capital program. A separate slide presentation accompanying those remarks will be posted on our website approximately one hour prior to the live webcast. The remainder of the webcast will be available for Q&A.

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.

We have identified in our latest Annual Report on Form 10-K and other filings with the Securities and Exchange Commissions a number of important factors that could cause future outcomes to differ materially from those set forth in these forward-looking statements.

Please refer to the quarterly Investor Package on our website for reconciliations of the non-GAAP financial measures discussed in this presentation to their most directly comparable GAAP financial measures.

Participating on this webcast are Lee Tillman, President and CEO; J.R. Sult, Executive Vice President and CFO; Lance Robertson, Vice President, Resource Plays; and Mitch Little, Vice President, Conventional. With that, I'll turn the presentation over to Lee Tillman who will begin on slide 3.

[Lee Tillman]

Thanks Zach. I'd like to extend my welcome to those listening, and begin by providing a summary of our 2015 performance.

Our 2015 capital program came in at $3 billion, below the forecast we shared last quarter of $3.1 billion and well below our original 2015 budget of $3.5 billion. Despite this nearly 15 percent reduction in capex, we exceeded our yearly production targets for both total Company and the U.S. Resource plays.

Production and G&A expenses were an intense focus for us last year, and we made considerable progress early in the cycle to reset our cost structure. In 2015, we reduced E&P production and total Company adjusted G&A expenses by more than $435 million, or 24 percent year-over-year.

Through a series of actions we began early last year driven by reduced investment activity, a strategic reorganization, and a further scale back of conventional exploration, we decreased our workforce by about 700 people, or over 20 percent, which will result in an annualized savings of about $160MM. We are positioned to capture full benefit from these meaningful cost reductions as we move through 2016.

Last October, in an effort to address the uncertain commodity price environment and continue prioritizing balance sheet protection, we announced a reduction of our quarterly dividend that will increase our annual free cash flow by over $425 million.

We closed on non-core asset sales of about $315 million, excluding closing adjustments, making considerable progress toward achieving our original goal of $500 million or greater. Importantly, the sale of the majority of our operated producing properties in the Gulf of Mexico included the divestment of the properties' significant abandonment liability.

In 2015, we achieved an organic reserve replacement ratio of 157 percent, excluding revisions and dispositions, at a competitive drillbit finding and development cost of about $12 per oil equivalent barrel. Our net proved reserves remain at approximately 2.2 billion oil equivalent barrels at year end, essentially in-line with 2014.

Finally, we ended the year with $4.2 billion in liquidity, including $1.2 billion in cash and an undrawn $3 billion revolving credit facility, positioning us well in the current environment.

Moving to some fourth quarter highlights on slide 4.

Our fourth quarter results reflected a continued focus on capital discipline, lower production and G&A costs, and sustained operational excellence – those elements of our business that we can control. Our capital spend came in below previous quarter, our production costs came in below our guidance – and we achieved 97 percent average operational availability. All the while still delivering total company production essentially flat with third quarter levels.

Unlike commodity prices, we're in control of our cost structure. Total Company adjusted G&A expense continues to trend lower, down 40 percent from the year-ago quarter. In the fourth quarter, we completed a strategic reorganization that better aligns our organizational structure with our business strategy. This included a further reduction in workforce, the full impact of which will be realized in 2016.

Operationally, Oklahoma continued to protect its valuable leasehold while delivering outstanding well results during the quarter in the SCOOP, highlighted by the performance of our first operated Springer well. Sequential production for the three resource plays was up slightly in the fourth quarter, driven by growth in Oklahoma, while Eagle Ford production held in flat and Bakken declined with reduced development activity.

We'll add more color to all these highlights as we walk through the rest of this presentation.

Slide 5 is an illustration of the cost savings I just mentioned. In a volatile environment with depressed commodity prices and compressed margins, we are focusing on every dollar.

On the left, you can see the yearly decrease in E&P production and total Company adjusted G&A expenses that equated to more than $435 million of savings, or 24 percent. In the fourth quarter, we

reduced the figure by almost $150 million, or 31 percent, from the year-ago quarter which you see on the right hand chart. As I mentioned, the full benefit from the fourth quarter reorganization and associated workforce reduction will be realized throughout 2016.

The majority of these cost savings are sustainable, and will be durable regardless of the commodity price.

Moving to slide 6. Total Company 2015 production available for sale from continuing operations, excluding Libya, averaged 431,000 net oil equivalent barrels per day, up 8 percent year-over-year which exceeded our original guidance of 5-7%.

Total Company fourth quarter 2015 production available for sale from continuing operations, excluding Libya, averaged 432,000 net oil equivalent barrels per day, in line with both the year-ago and previous quarters.

In the fourth quarter, production was higher compared to the third quarter in Oklahoma, EG, and U.K. while Eagle Ford production was flat. This was offset by lower OSM production due to planned maintenance activities and a decrease in Bakken production associated with planned low completion activity.

The sequential decrease in other North America production was primarily due to a full quarter without volumes from the East Texas North Louisiana asset sale which closed in August and a small impact from the Gulf of Mexico sale which closed in December.

Moving to slide 7, the U.S. resource plays finished the year above their 2015 production growth target of 20 percent.

In the fourth quarter, U.S. resource play net production averaged 214,000 oil equivalent barrels per day, slightly above the third quarter average.

As I mentioned on the previous slide, Eagle Ford production was flat sequentially supported by flat net wells to sales. An increase in Oklahoma Resource Basin production driven by a full quarter of benefit from the Smith infill project in the SCOOP area more than offset a decline in the Bakken due to our capital allocation decision to keep completions activity at reduced levels.

Lance will provide more detail on each asset's individual performance in a moment.

On slide 8, you can see that we delivered an organic reserve replacement ratio of 157 percent with drillbit F&D costs of $12 per oil equivalent barrel, which excludes revisions and dispositions.

We added 246 million oil equivalent barrels of proved reserves in North America E&P, and nearly all of our additions were driven by drilling activity, downspacing, and improved well performance. Market pricing effects led to North America E&P negative revisions of 173 million oil equivalent barrels.

2015 net proved reserves are approximately 2.2 billion oil equivalent barrels, flat with prior year, and were 81 percent liquids and 72 percent proved, developed.

With that, I will hand it over to J.R. to review the Company's financial results.

[J.R. Sult]

Thanks Lee. Once again, I have only two slides today so I will be brief. Turning to slide 9, adjusted loss from continuing operations was $323 million, or $0.48 per diluted share, in the fourth quarter, compared to adjusted loss of $138 million, or $0.20 per diluted share, in the prior quarter. Results this quarter were negatively impacted by lower average crude oil and condensate price realizations which were down over 10 percent quarter-over-quarter along with higher exploration expenses from the Solomon well in the Gulf of Mexico.

Reported net loss from continuing operations was $793 million, or $1.17 per diluted share in the quarter, compared with a loss of $749 million, or $1.11 per diluted share last quarter.

The adjustments to reported loss from continuing operations for the fourth quarter primarily included a goodwill impairment charge in the North America E&P segment, an unproved property impairment relating to Canadian in-situ assets offset by a gain on the sale of the Gulf of Mexico assets.

Total company cash flow can be seen on Slide 10. For the fourth quarter of 2015, operating cash flow before changes in working capital was $278 million down from the third quarter of 2015 primarily due to lower commodity price realizations. Total net cash provided by operating activities was $352 million during the quarter.

Additions to property, plant and equipment for the period were $561 million as compared to $595 million in the prior quarter. During the quarter, we received proceeds from the disposal of assets for $120 million, the majority of which came from the sale of our Gulf of Mexico properties.

During the fourth quarter, we used $700 million of short-term investments toward retiring $1 billion of senior notes at maturity. On December 31, our cash balance was approximately $1.2 billion which, when combined with our undrawn revolving credit facility, resulted in total liquidity of $4.2 billion.

With that brief summary, I'd like to hand it over to Lance Robertson to review the Company's North America E&P financial and operating performance for the quarter.

[Lance Robertson]

Thanks J.R.

Before I take everyone through our operational highlights by asset, I would like to spend a moment to discuss the quarterly financial results for the North America E&P segment.

Turning to slide 11, the North America E&P segment had an after-tax loss of $219 million during the quarter, compared to a loss of $61 million in the prior quarter. The increase in segment loss quarter

over quarter was due to lower average crude and condensate price realizations and higher exploration expenses as J.R. just mentioned.

North America E&P sales volumes averaged 258,000 BOE per day in the fourth quarter, down slightly from both the year ago quarter and prior quarters primarily due to the full quarter without volumes from the East Texas North Louisiana asset sale which closed in August and a small impact from the Gulf of Mexico sale which closed in December. I'll address the individual assets' production variance in the coming slides.

Slide 12 highlights some of the significant cost reductions we've been realizing in the North America E&P segment. For 2015, we reduced production and other operating costs per BOE by 23 percent, reflecting savings sourced from ongoing internal efficiency and commercial improvements. Production costs per BOE averaged $7.38 for the year, below the low end of our guidance range, and other operating costs averaged $4.71, at the low end of our guidance range.

In the fourth quarter, production costs averaged $6.91 per BOE, nearly 30 percent lower than the year-ago quarter. North America E&P production and other operating costs per BOE are down 12 percent from the year-ago quarter. Approximately $1 per BOE of our other operating costs in the fourth quarter was related to certain non-recurring items.

With that overview of the North American E&P financial performance, I will move to review the operational activity in the fourth quarter from our three U.S. resource basins.

Starting with the Eagle Ford on slide 13… as shown in the chart in the upper-left, we produced an average of 128,000 net BOE per day in the fourth quarter, flat with the prior quarter on flat net wells to sales.

The chart in the lower left illustrates each year of well performance since we entered the Eagle Ford in 2011. We've plotted the average BOE per lateral foot on a 30 to 180 day basis. As you can see, we

have increased our well productivity every year through a combination of technology application, extensive reservoir modeling, geophysical mapping, and multi-variant analysis.

As we’ve discussed before, we’ve been making great strides in lowering costs and improving efficiencies. The fourth quarter was no different in the Eagle Ford, with further reductions in completed well costs, faster drilling while landing in zone, and more frac stages per month per crew. All of those details can be found on this slide.

We look forward to continuing these trends of increased well performance, lower costs, and greater operational efficiency as we move to the future.

Turning to slide 14, we highlight some of our co-development well results brought to sales in the fourth quarter that have 30 days of initial production.

The Upper Eagle Ford wells results in our core Karnes County acreage had 30 day IP rates that ranged from 1,040 to 1,265 BOE per day. We now have a total of 28 Upper Eagle Ford wells online with at least 90 days of cumulative production and they are performing in line with the Lower Eagle Ford type curve for the same area. The Upper Eagle Ford performance supports the 2P resource additions and growth in inventory announced in the third quarter of last year. We continue to pursue co-development across our core acreage position, combining Austin Chalk, Upper and Lower Eagle Ford wells with a focus on delivering the highest value from a drilling unit.

Turning to slide 15 and the SCOOP / STACK where our Oklahoma team had an outstanding quarter. Production averaged 28,000 net BOE per day in the fourth quarter, up almost 50 percent from the year-ago quarter and up 22 percent sequentially.

We brought our first company-operated Springer well to sales in the SCOOP, and its initial production rates have exceeded our expectations on both a 30 and a 60 day basis. We completed the well with more proppant and at tighter stage spacing than offset wells, and the liquids cut is nearly 90 percent, substantially all of which is crude oil.

We also brought a SCOOP Woodford well online in the quarter, the Tyemax, in the down-dip condensate window that flowed an impressive 30-day rate of 2,900 BOE per day, the highest IP rate of an XL well in the basin to date.

Finally, we benefitted from a full quarter of production from our operated Smith infill wells in the SCOOP Woodford, which came online late in the third quarter. These wells are performing in-line with our type curve expectations, with condensate rates coming in higher than expectations. The successful pilot has confirmed our initial infill development strategy on 107 acre spacing.

Despite compelling operated results in Oklahoma, our 2015 drilling program was largely focused on protecting our valuable leasehold. As our focus on defending term leases continues into 2016, ample opportunity remains for us to continue optimizing costs through efficiencies and driving further improvement in well productivity. Last year's results, particularly the Smith infill pilot that was our first operated pad development, gave us confidence that we can move completed well costs materially lower when commodity prices improve and the opportunity comes to grow activity in the SCOOP and STACK plays.

Turning to slide 16, I'll point out some of the locations of our fourth quarter activity.

Beginning in the northern part of the play in the STACK, we drilled one operated STACK Meramec leasehold well in the quarter, the Alta, that has a 30-day rate of 619 BOE per day and was 76 percent liquids. We also participated in two outside operated Meramec wells in the quarter whose 30-day IP rates ranged from 668 – 1,958 BOE per day and were 85-62% liquids. Consistent with early development in other basins, we are continuing to delineate, test the boundaries of the phase windows, and optimize completion practices while focusing on lease retention.

Moving south to the SCOOP… in addition to having excellent initial production rates, our Springer oil and Woodford condensate wells both provided valuable confirmation of our understanding of the phase windows. The Springer well, the Newby 1-7, is on the border of Grady and Garvin counties in the heart of the southern Springer oil trend. As I mentioned on the previous slide, we utilized an

enhanced completion on this well and have generated very promising early results. In fact, the well's 60-day production rates are consistent with the 30-day rates, which are contributing to the performance well above the majority of surrounding area Springer wells. We have TD'd our second operated Springer well just north of the Newby, also on the Grady / Garvin county line and expect to bring it to sales in the first quarter.

I'd also like to briefly touch on our SCOOP Woodford Tyemax well in a bit more detail. This extended lateral well is located in south-central Grady County area where the Woodford shale is more highly fractured, in the condensate window of the play. In the first 30 days online, our Tyemax well is exceeding all other SCOOP Woodford extended laterals in the basin driven by a well selected landing zone and elevated reservoir pressure.

Before I leave Oklahoma, I'd like to point out that in 2015, we secured about 14,000 net acres in the SCOOP and STACK through a series of grassroots leasing efforts. The leases were predominantly focused in the core condensate area of the STACK Meramec, and secured at a very competitive average cost of less than $3,000 an acre. With a 2P resource of 1.6 billion BOE, we have a terrific opportunity to create value through developing our SCOOP and STACK position when commodity prices stabilize and improve.

Moving to the Bakken on slide 17. Production averaged 58,000 net BOE per day this quarter, up 5 percent compared to the year-ago quarter and down 5 percent from the third quarter. The fourth quarter was the Bakken's second consecutive quarter with just 5 wells to sales, due to our decision to maintain a reduced level of activity in the Williston Basin.

The Bakken team continues to focus on cost management and driving operating costs to among the lowest in the basin. Over the past year they have driven unit costs down by over 20% as they focused on effectively managing their base production business. Cost improvement, along with best-in-class drilling performance, is positioning our Bakken opportunities for a bright future.

Our large scale water gathering system is now handling over 50% of our produced water and ongoing expansion of the system is expected to be complete in the second half of 2016. We anticipate the system will manage approximately 80 percent of our produced water by year-end; significantly reducing our water handling costs. The majority of spending attributed to this project was incurred in 2015.

The chart in the lower left illustrates a yearly progression of our Bakken well performance since 2011. Average BOE per lateral foot is plotted on a 30 to 180 day basis, and as you can see, we have improved well productivity every year primarily through optimization of our completion designs and improving artificial lift efficiency.

With that, I'll hand it over to Mitch Little, who will review the highlights of our Oil Sands Mining and International E&P segments.

[Mitch Little]

Thanks, Lance.

Before turning to our International E&P segment, I will start with a quick overview of our Oil Sands Mining performance on slide 18. The Oil Sands Mining Segment delivered another quarter of strong operational results. The mine produced 49,000 barrels of synthetic crude oil per day net of royalty, down from the mine's all-time record of 57,000 barrels per day in the third quarter, but above guidance as the mine continues to demonstrate an improving trend of higher operational availability. Planned maintenance in the fourth quarter was also completed on time and on budget.

Notably, operating costs per synthetic barrel before royalty were just over $28 in the fourth quarter. This was the second consecutive quarter of operating costs below $30 per barrel, and down more than 35 percent from the year-ago quarter driven by the combination of higher mine reliability and utilization rates, the concentrated focus on sustainable cost reductions, as well as the benefits from the strengthening US dollar during 2015.

OSM reported a loss of $6 million during the fourth quarter, compared to a loss of $11 million in the prior quarter, primarily driven by lower operating and DD&A expense. We continue to be encouraged by the mine's progress in reducing operating costs and sustaining capital. Discretionary debottlenecking and expansion projects have been deferred, and the JV partners and operator are collectively focused on driving further cost and operating efficiencies into the business.

Moving to slide 19, I would like to start with a quick review of quarterly financial results from International E&P. Segment income decreased from the previous quarter to $19 million, reflecting lower average crude oil and condensate price realizations partially offset by higher sales volumes. We finished the year strong with higher quarterly sales volumes which were driven by full quarter benefits from the successful well intervention program and Alba C-21 well in Equatorial Guinea, as well as higher operational availability.

Equity earnings from our EG onshore processing plants were $47 million in the quarter, in line with the previous quarter as higher sequential LNG sales offset by lower average Methanol and NGL prices.

We continue to focus on proactive cost management across all segments, driving repeatable savings that help protect margins both within, and through the current commodity price cycle. We achieved full-year 2015 unit production costs, in the International E&P segment, excluding Libya, of $5.33 per BOE. This represents a reduction of approximately 30 percent from 2014 unit costs. I am extremely proud of the way our employees across the Company have embraced the ongoing challenges and am equally confident that they will continue to rise to the occasion as we navigate through the remainder of the current down cycle. We remain deliberately focused on challenging the status quo, and are purposefully scrutinizing every contract, project, and task for its relevance and / or competitiveness in the context of the challenging macro environment we find ourselves in.

Moving now to slide 20, production available for sale from Equatorial Guinea averaged 104,000 net BOE per day in the fourth quarter, up 5 percent sequentially as we benefitted from a full quarter of production from the Alba C21 development well and successful well intervention program.

The Alba field compression project achieved a major milestone in January with the successful jacket and topsides installation campaign. Following completion of planned onshore maintenance activities, the Alba field returned to full production in early February. The resulting production impact for the downtime associated with the installation and planned maintenance will be approximately 20,000 net BOE per day in the first quarter of 2016. Hook-up and commissioning activities on the Alba compression project are in progress and the project is on budget, and on schedule for start-up mid-year. Once on-line, the project is expected to extend field plateau production by an additional two years, while extending field life by up to 8 years, resulting in field operations beyond 2030.

Our continued focus on cost management, while maintaining high operational availability, and a strong commitment to our HES performance standards, serves to protect operating margins. These efforts combined with the expected startup of three long cycle projects in 2016, including the EG Compression Project, the Gunflint Subsea Development in the Gulf of Mexico, and the Atrush Development in the Kurdistan region of Iraq, will contribute meaningful operating cash flow for the corporation despite the challenging commodity price environment.

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

[Lee Tillman]

Thanks Mitch.

2015 was a year of transition and adjustment to a much lower commodity price environment, and we were proactive in taking the necessary actions to address that, while also advancing the U.S. resource plays.

Reducing capital spending, lowering production and G&A costs, enhancing productivity, and progressing non-core asset sales allowed us to be flexible and adapt as business conditions changed last year. More of that same discipline will be required in 2016.

In a separate press release today, we announced our 2016 capital program of $1.4 billion, over 50% lower than our 2015 program, to do just that. We will continue prioritizing balance sheet protection and leveraging our operational and investment flexibility to best position Marathon Oil for a lower for even longer commodity price environment.

We'll host a live call tomorrow morning to provide more details around those plans.

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