THIRD QUARTER 2017 EARNINGS REVIEW REMARKS

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[Zach Dailey]

Welcome to Marathon Oil Corporation's third quarter earnings review. I'm Zach Dailey, Vice President of Investor Relations. 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 2nd at 8 am 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; Dane Whitehead, Executive Vice President and CFO; and Mitch Little, Executive Vice President of Operations. With that, I'll turn the presentation over to Lee who will begin on slide 3.

[Lee Tillman]

Thanks Zach. I'd also like to extend my welcome to those listening. I'll begin on slide 3 with a familiar slide we've consistently used to provide a broad overview of our priorities at Marathon Oil. We've made some outstanding progress executing all aspects of this playbook, and are well positioned to deliver on the final step, our over-arching objective: delivering profitable growth within cash flows and achieving that at moderate oil pricing.

In the next few slides, Dane and I will put our year to date results into context for each of these steps in a bit more detail. Dane will start on the next slide by highlighting what we view as the foundation upon which we're building the business: a strong balance sheet.

[Dane Whitehead]

Thanks Lee. When I joined Marathon earlier this year, I saw a company with a good balance sheet that had improved, but also saw an opportunity to accelerate that progress and make it even stronger. We put that into action in the third quarter, pricing $1 billion of 4.4 percent senior notes that mature in 2027, and then used those proceeds, plus cash on hand to redeem our 2017, 2018 and 2019 maturities. We've illustrated these transactions in the top left chart of slide 4, and they created numerous benefits, such as reducing gross debt by about $765 million, extending our next debt maturity out to 2020, and reducing our annual cash interest expense by nearly $65 million.

In parallel and complimentary to the new bond offering, we extended our undrawn credit facility to 2021 and upsized it to $3.4 billion. That, combined with $1.8 billion of cash on hand, provides total liquidity of $5.2 billion at the end of Q3.

Another step we've taken to enhance our financial flexibility has been to continue to build out our hedge positions. We view hedging as an important commodity risk management tool, that allows us to price protect a portion of our enterprise cash flows. We've employed a mix of instruments, but continue to prefer three-way collars as a way to offer protection to the downside, but retain some upside as well.

We've been opportunistic in legging into our positions. And as you can see in the bottom graph, as of September 30th, we hedged approximately 70,000 barrels of oil per day in the fourth quarter of 2017, with an average floor price of just under $54. Since then, we've swapped another 40,000 barrels per day for November and December at just over $54.

For 2018, we've hedged 75,000 barrels per day in the first half of the year, and are slightly less hedged in the second half, at 62,000 barrels per day – all with three way collars. Since the end of the third quarter, we added another 10,000 barrels per day of three way WTI collars and our weighted average floor price in 2018 is approximately $51.

And although gas is a smaller element of our U.S. production and cash flows, we've built a solid 2018 natural gas hedge position using three ways with a weighted average floor of $3.02 per mmbtu. Expect us to continue to add to our hedge positions as the market provides opportunities in the future.

All these balance sheet and commodity hedging moves have improved our already strong financial position which is the foundation of our business and enables us to confidently execute on our strategy.

I'll flip it back to Lee now to address the next three slides, then I'll come back to discuss cash flow.

[Lee Tillman]

I'll touch on our relentless focus on costs on slide 5.

While we can't control pricing, we can control our costs which, along with our shift to a resource plays weighted production mix, allows us to expand our margins. Since my first day at Marathon Oil, we've been focused on lowering the cost structure across our entire business, and have continued to make significant progress.

The top graph highlights the downward trend in production expenses, both on a unit and absolute basis, despite recent inflationary pressures. Total E&P production expense is expected to be down over 40 percent from 2014 with U.S. E&P production costs per BOE expected to decrease about 45 percent over the same period. And for the third quarter, we achieved a record low U.S. E&P unit production expense since becoming an independent E&P company in 2011.

We captured over $100 million in annualized G&A expense savings over two years ago, as we took early action to properly scale our organizational capacity to align with the "lower for longer" outlook and our portfolio simplification to focus on the U.S. resource plays. In addition to those organizational and workforce initiatives, savings across all components of G&A --compensation, benefits, contract labor, outside services-- have total adjusted G&A costs expected to be down about 35 percent from 2014 levels.

This intense focus is lowering combined annual production expense and G&A costs by over $700 million from 2014. The lowest cost, highest margin producer will win, regardless of commodity environment.

Turning to slide 6, we've transformed our portfolio as fast and as dramatically as any other company in the large cap E&P space in recent years, better aligning our asset base with our strategy by simplifying and concentrating our portfolio to the four lowest cost, highest margin US resource plays. The largest transactions in the last two years saw us divest our high cost Canadian oil sands and Wyoming businesses for about $3.4 billion and acquire additional STACK acreage and enter the Northern Delaware.

The top chart illustrates how the dramatic portfolio shift has enabled us to concentrate more of our capital allocation to the U.S. resource plays. In 2013, only about two thirds of our capital was allocated to the U.S. resource plays. But since then, thanks to our portfolio work, over 95 percent of our budget is allocated to the resource plays, and you can expect this to be the 'new normal' for us going forward.

As we move into 2018 and the years ahead, our production mix will continue to become more concentrated towards higher margin barrels, with roughly 60 percent of this year's production coming from our four resource plays as illustrated in the bottom chart. For perspective, that 60 percent is about twice the contribution from the resource plays in 2013. And we expect this figure to keep trending up in the years ahead, expanding our margins while driving both returns and cash flow higher.

On slide 7, we arrive at the fourth and final "stair step" of our playbook, which is profitable growth within cash flows—this is the outcome of all the hard work just described and has been the ultimate objective of Marathon's transformation. I'll address the growth component and then let Dane walk through our progress toward cash flow neutrality.

Today, thanks to another quarter of outstanding execution, we've again increased our 2017 production guidance while decreasing capex to $2.1 billion, the low end of our guidance. In the top left chart, you'll see that we raised the bottom end of our full year 2017 production guidance range to 350 to 360,000 boe per day, driven primarily by strong performance in our U.S. resource plays. This equates to total Company year-over-year growth for both oil and BOE of 9 percent at the midpoint, adjusted for divestitures.

In the bottom left chart, you can see our upwardly revised guidance for the 2017 exit rate in the U.S. resource plays of 25 to 30 percent. This is up from prior guidance of 23 to 27 percent, driven by strong new well performance in all four assets and reliable base performance.

As a result of the 2017 exit rate momentum, we will carry a larger, higher margin production base into 2018 with the resource plays expected to account for a more significant proportion of the total production mix. This shift delivers strong operating cash flow and underpins our ability to deliver growth consistent with our 2017 to 2021 benchmark production CAGRs within cash flows now at flat $50 WTI.

I want to emphasize that production growth for Marathon is an outcome of our disciplined capital allocation to the highest risk adjusted return opportunities while living within our means. With that, I'll pass it over to Dane to specifically address cash flow.

[Dane Whitehead]

Thanks Lee. On slide 8, I'll address the last element of the final stair step, which ties together our strategy: achieving our objectives while living within cash flows.

Last quarter, we forecasted a cash flow outspend for the year of about $200 to $300 million at $50 WTI. Through a combination of better base and new well performance, lower costs, lower capex, and some improvement in commodity prices, we now envision free cash flow neutrality for full year 2017, inclusive of dividend and changes in working capital.

The waterfall shows the progress we've made through the first three quarters of the year, actually increasing our current cash balance year to date before A&D and debt repayment. And while the year to date cash balance includes a positive change in working capital of about $200 million, we expect the full year benefit to be reduced to around $100 million.

Keep in mind that these figures do not include the second installment of our OSM sale of $750 million that we'll receive on March 1st, 2018.

Our expected 2017 production growth rate, driven by strong exit rate momentum into the higher margin resource plays, will provide a solid base of cash flows to fund our 2018 program. And while it's still too early to talk about specifics of a 2018 capital plan, our objective next year remains to deliver returns-focused growth within cash flows. The improvement in our performance expectations for 2017 bolsters our confidence heading into 2018.

With that, I'll hand it over to Mitch Little who will discuss our third quarter operations in a bit more detail.

[Mitch Little]

Thanks Dane. I'll begin on slide 9 with an overview of third quarter highlights. Throughout the year, our teams have been singularly focused on consistently delivering outstanding execution across the entire Company. And in the third quarter, we delivered again, both in the U.S. and internationally.

Total Company production was up 6 percent sequentially, on the back of a 12 percent rise in resource play volumes. Importantly, resource play oil production was up 14 percent sequentially, driven primarily by a 20 percent increase in our Bakken production.

Eagle Ford production averaged 101,000 BOE per day, up slightly from second quarter despite the downtime effects associated with hurricane Harvey and fewer wells to sales. All credit goes to our exceptional team and how they safely and efficiently managed through the storm and its aftermath. The Eagle Ford's third quarter performance is a perfect example of how hard work, collaboration, investment in technology, and excellent new well performance are collectively being leveraged to deliver standout results.

Our five new Middle Bakken and Three Forks wells in Hector averaged an outstanding 2,380 BOE per day, and highlights Hector's newfound ability to compete with our Myrmidon asset in the Bakken.

Oklahoma production rose 18 percent from second quarter, supported by better than expected results in the STACK volatile oil window, while continuing to capture term leases, delineate, and progress our infill spacing pilots.

In our first full quarter after the close of our Northern Delaware deals, we brought two notable Wolfcamp X-Y wells online in Eddy County, and have just recently added a fourth rig to our fleet.

Our cash flow generating international assets also fired on all cylinders, delivering production above the top end of guidance, despite the beginning of planned turnarounds in the UK. The strong performance was primarily driven by facilities and well optimization in EG, where we brought in over $180 million of EBITDAX in the quarter.

Flipping to slide 10, I'll highlight our U.S. production. Third quarter production of 243,000 BOE per day exceeded the top end of our guidance due to better than expected well performance, strong base production, and operational efficiency gains. In the resource plays, we delivered 12 percent sequential growth, as continued strong Bakken and Oklahoma performance led the way. The increased contributions from Bakken and Permian translated to sequential oil growth of 14 percent in the resource plays, exceeding BOE growth.

For the fourth quarter, we expect further growth in the resource plays and we're guiding U.S. production to a range of 255,000 to 265,000 BOE per day. You'll see in the footnote that in our reported results we've adjusted for divestitures, all of which have come from our "other U.S. E&P" category.

Diving into the specific assets on slide 11, I'll begin with the Eagle Ford which posted another noteworthy quarter with production of 101,000 net BOE per day, up from the prior quarter. This was accomplished in spite of fewer wells to sales, a field wide shut-in, and downstream curtailments that resulted from Hurricane Harvey's impacts along the Gulf Coast.

Our third quarter performance was once again underpinned by strong well performance and outstanding execution. The benefits of higher intensity completions and engineered flowbacks continue to enhance well performance across our leasehold. One pad in particular, the Guajillo South, demonstrated the benefits of these two operational strategies with a pad average IP 30 of over 1,900 BOE per day, an outstanding result for this area of the field. While the results of the Guajillo pad are not necessarily indicative of all of our Atascosa County opportunities, it does serve as another positive indicator of our ability to improve performance across this portion of our Eagle Ford position, and represents the fourth consecutive Atascosa County pad that's exceeding expectations. The relentless focus on well performance throughout our acreage is evident in the bottom left chart which illustrates that the 90 day cumulative well production from our 2017 program is up 40 percent when compared to 2011 and is shaping up to be the best year in the history of this asset, with an impressive year-over-year improvement of about 15 percent.

Operationally, another Marathon record was set this quarter as the average spud to TD time was reduced to just under 7 days, an improvement of over half a day from our previous record which was set in the first quarter of this year. This attention to detail and continuous incremental improvement throughout our operations has allowed us to mitigate the inflationary pressures on our completed well costs, as evidenced by flat sequential well costs in the third quarter.

Looking forward to the fourth quarter, we anticipate a relatively flat production profile and free cash flow generation with an additional 30 to 35 wells to sales.

Slide 12 summarizes our third quarter results in the Eagle Ford with wells outside Karnes County highlighted in lighter blue. It was a quarter in which we completed wells in multiple areas, and as has become standard practice for us, we utilized different frac techniques to optimize performance across our acreage. We had strong results across Atascosa, Karnes and Gonzales counties in both the oil and condensate windows, with about half of our wells outside the core Karnes Country area. In aggregate, the average IP 30 for the 36 wells brought to sales in Q3 was an impressive 1,600 BOE per day, with 67 percent oil.

Once again, the Eagle Ford delivered an outstanding quarter with a consistent production profile, efficient and cost effective operations and positive free cash flow, all against the backdrop of a significant operational disruption.

Turning to slide 13, the Bakken has fully delivered on the turnaround story we expected from the asset when we rolled out our ambitious activity ramp at the beginning of the year, in response to last year's early success with higher intensity completion designs. After reversing production declines and returning to growth in Q2, the asset posted impressive third quarter results with a sequential production increase of approximately 20 percent.

Within our 20 wells to sales, we had a mixture of West Myrmidon, East Myrmidon and Hector; both Middle Bakken and Three Forks. Across the asset we have moved to more aggressive completions with higher proppant loading and diversion technology to achieve a greater induced fracture complexity. In our Hector Middle Bakken wells, we successfully trialed a high intensity slickwater design that has helped prove that a good portion of Hector can be upgraded to compete economically with our Tier 1 Myrmidon acreage. The five Q3 Hector wells, comprised of two Middle Bakken and three Three Forks wells, had an impressive average 30 day IP of 2,380 BOE per day, with about 85 percent oil.

In the bottom left chart, you can clearly see the year-over-year performance improvements from all of our Bakken wells, with a step change improvement in 2016. Year to date 2017 results show the trend continuing, and demonstrate the continuous improvement mindset that's been embraced across the organization.

The charts on slide 14 illustrate how Marathon's well performance competes with peers and the recent results continue to impress. Through our innovation and enhanced completion design we are not only setting new Marathon records - we are also setting new benchmarks for the Bakken overall.

The upper left chart shows Marathon has delivered six of the 10 best Middle Bakken wells in the Williston basin. Notably five of the top 10 were brought on line in Q3, and perhaps most impressively the single best well is from our Hector area, which does not enjoy the same geologic advantages as our Myrmidon acreage, highlighting the great technical work done by our team to significantly alter the completion approach, and significantly elevate the returns of this program to compete with the top tier of our resource play portfolio.

Equally impressive, the bottom left chart highlights that Marathon has also delivered six of the top 10 Three Forks wells in the basin, with the majority of those wells also brought to sales in Q3, including the second best Three Forks producer in the basin, our Harley well in West Myrmidon.

Turning to slide 15, you can see that we've been able to achieve results across our acreage that are setting new Marathon single well records. Consistent with our delineation plan for Hector, we are moving across our position to test farther to the east. With two highly successful pads behind us in Q3, we've just recently begun flowback on the Chapman pad, our third overall, and most eastern test of the new completion designs. Though early in the flowback period, the two new wells have an average 24 hour IP of 4,265 boe a day with 85 percent oil.

Moving to slide 16, we delivered third quarter production of 58,000 BOE per day in the Oklahoma Resource Basins, up 18 percent from the prior quarter. We brought 15 new wells to sales, including the Landreth well in the Meramec volatile oil window. The Landreth was a standard lateral well where we employed our latest generation completion design, and it posted a very impressive 30 day IP of just over 2,400 BOE per day, 59 percent oil. All three of the Meramec volatile oil wells brought to sales in Q3 are performing above our 1.5 million BOE extended lateral type curve, despite the fact that two of the wells were drilled as standard laterals.

In the third quarter we also brought to sales our first Kingfisher county Osage well, the White 1-13 with an IP 30 of 850 BOE per day, 55 percent oil. We completed the well with a smaller, lower cost completion based on learnings from Osage completions in the surrounding areas. The drive towards lower completed well costs, coupled with the encouraging early well performance, provides some optimism for future development options for a zone that currently features minimally in our near term development plans.

We'll continue to selectively integrate these delineation tests to assess the full potential of our 200,000 net acre position in the STACK, allowing us to optimize our future development plans for Oklahoma.

For the balance of the year we expect to bring 20 to 25 wells to sales, about 40 percent of which will be leasehold protection. The remainder will primarily be from our two remaining 2017 infill pilots, our Tan XL infill, testing 9-well per section spacing in the Meramec volatile oil window, and the Eve, our third full section Meramec black oil infill where we're testing a 6-well per section spacing design across two benches in the Upper and Lower Meramec.

The Eve pilot was completed late in the third quarter and was recently put on flowback, so we're currently in the cleanup and artificial lift optimization stage. Leveraging the data captured from the Yost and Hansens trials, the team incorporated significant design modifications on the Eve pilot to accelerate our learnings in the early phases of the field's development. On the direct offset wells in the upper Meramec we adopted a reduced energy completion design with tighter cluster spacing, a design we engineered to optimize contact with untapped resource. We also elected to go with a 6-well density design after incorporating data from the first two pilots. We landed two of the infills at the base of the lower Meramec, which is approximately 170 feet below the Upper Meramec landing zone in this section, and treated both with some of our highest intensity completions in the Meramec Black Oil window to date, at nearly 3,000 pounds per foot proppant.

Completion activities are currently underway on the Tan infill in the volatile oil window of the STACK, with first sales expected later this quarter. The Tan infill pilot includes 8 extended laterals, along with a single SL well as an extension from the parent well that was also an SL. This configuration effectively completes the XL pattern, at 9-wells per section spacing, across two landing zones. Similar to our approach on the Eve infill, a reduced energy stimulation approach is being adopted on the direct offset wells in this section. The revised design is intended to maximize near well-bore complexity along the entire lateral for optimal drainage. For the remainder of the wells in the section, we will be customizing our design with a focus on full section returns.

More to come on these two infill pilots in the next quarter.

Referring to slide 17, I'll highlight some of the positive third quarter well results delivered by our Oklahoma team. In Canadian County, the Barlow standard lateral well delivered an IP 30 of over 900 BOE per day, and the Zum Mallen, also a standard lateral well, coming in with an IP 30 of almost 1,300 BOE per day. Further west into Blaine County you can see the Landreth that I mentioned earlier, along with the HR Potter and the Redman BIA which had an IP 30 of over 1,800 BOE per day.

In the SCOOP, we brought online our first Springer infill pilot, the Marie, which is the third full section industry Springer infill pilot in Grady County. The four Springer wells were completed with a high intensity design that also contained approximately 30 percent more fluid than the previous two industry infill pilots. We have seen total fluid rates on par with industry offsets, but are experiencing longer clean up times which we believe can be attributed to our modified completion design, so we will likely need some additional performance data before determining the impact of the higher intensity completion style.

On slide 18, I'll turn to the Northern Delaware, where we have impressive results from a couple of recent Eddy County wells to share. In the third quarter, the Northern Delaware contributed 9,000 BOE per day net to Marathon which reflects our first full quarter owning the asset and is up from just over 4,300 BOE from the prior quarter.

We delivered five operated wells to sales this quarter while running three rigs. Our team has successfully ramped activity and built sufficient inventory to support a dedicated frac crew which we secured during the quarter. Securing this crew allows us to quickly start leveraging local Northern Delaware experience and execute efficiently while expanding our direct sourced sand model to a third basin. The crew is off to a great start, performing better than planned, and is currently completing their seventh well. Our completions to date utilize high rate, high density, 100 percent slickwater frac designs which are in the 2,500 pounds per foot proppant range.

Our last two wells, both completed with high intensity fracs in the Wolfcamp X-Y interval, have given us another look at the performance we can expect from our Eddy County acreage. The Chicken Fry 1H registered an IP 30 of 2,020 BOE per day, 67 percent oil, and our El Presidente 4H well came in with an IP 30 of 1,500 BOE per day and 69 percent oil.

It's this type of well performance and continual improvement that has given us the confidence to pick up another rig, our fourth, early in Q4.

Behind the scenes, the subsurface team has advanced our ability to utilize our integrated workflow – including coupling newly acquired 3D seismic to better target and steer our laterals to stay in the highest quality landing zones. The team looks forward to further utilizing our 3D data to push the limits on targeting and identifying new opportunities in the incredible stack of oil bearing rocks in the Northern Delaware basin.

Looking forward to Q4 - with our operations now ramping up, we are guiding to bring on another 10 to 15 wells to sales.

On slide 19, we can talk about a few of those upcoming wells. The El Presidente and Chicken Fry wells, which I just discussed, are both in Eddy County and they are highlighted in dark blue boxes. We've also included some of our 4Q wells which will include delineation across both Eddy and Lea Counties shown in light blue. Our activity in the fourth quarter will continue to be focused on Bone Spring and Wolfcamp targets.

In our Southern Comfort DSU we drilled two 7,500 foot laterals in the Wolfcamp XY. We are currently on location with the frac crew completing both of these wells. The two well pad will test frac trials pushing the limits on efficiency and stage spacing.

During this quarter we also successfully drilled the Grama Ridge DSU with three wells, two 2nd Bone Spring, drilled at a 4-well per section density, as well as a 3rd Bone Spring test. The 3rd Bone Spring test was a seismically derived target with impressive offset well performance. The 3D seismic enabled us to target the best intervals and anticipate some of the natural fracturing in the area. We successfully placed all three wells precisely where we wanted them and are looking forward to getting the wells frac'd next month.

We also spud, and are well advanced in the drilling of our Cypress spacing pilot which we featured in last quarter's call. In the 320 acre DSU pilot, we are testing multiple benches within the Wolfcamp and Bone Spring intervals. The team has rapidly integrated learnings from recent area activity, and made real time modifications to landing zones in a couple of wells demonstrating the power of an integrated workflow and nimbleness provided from real time data monitoring. Drilling operations will finish in Q4 and we expect to complete and bring the wells to sales during the first half of 2018.

We recently spud the Cave Lion 5H, our first Wolfcamp target within our Red Hills acreage, in Southern Lea County. We moved into this highly prolific area late last month when we picked up or fourth rig and we expect to complete the first well in the DSU in early 2018.

Moving to slide 20, I'll talk a bit about our International E&P highlights before handing back to Lee.

Our International segment had another excellent quarter, fully reflecting our execution focus across the entire business. The team delivered production of 126,000 net BOE per day, above the top end of our guidance range. EG production averaged 112,000 net BOE per day, up from Q2 driven by facilities and well optimization. They delivered an impressive $183 million of EBITDAX in the quarter, helping fuel our development in the U.S. resource plays.

Libya continues to ramp up, with net production averaging 23,000 BOE per day in Q3. While encouraging, we continue to exclude Libya from our guidance due to uncertainty associated with the political and operating situation there.

Finally, our fourth quarter International production guidance of 120,000 to 130,000 net BOE per day (excluding Libya) is in line with third quarter volumes and includes the completion of planned turnaround activity at Brae and Foinaven in the U.K. With that, I'll turn it back to Lee for final comments.

[Lee Tillman]

Thanks Mitch, I'll wrap up on slide 21.

We have executed consistently against our playbook throughout 2017. Our execution proof points include the strength of our balance sheet, a low cost structure, a relentless focus on operational excellence, maintaining flexibility and agility in our capital allocation and an ongoing commitment to portfolio simplification and concentration. We don't pretend to predict pricing but rather want to prepare our business to be successful across a broad range—and a more moderate range – of pricing. Our objective remains to deliver profitable growth within cash flows, with growth an outcome of our returns focused capital allocation. And for full year 2017, we now expect to live within our means, including dividend and working capital, while raising our production guidance and lowering capex.

Doing more with less has been our consistent theme all year long. All of this is designed to deliver long term value and returns to our shareholder.

Total E&P production growth is now expected to be 9 percent at the midpoint and the resource plays exit rate growth has been increased to 25 to 30 percent--and these raises apply to both BOE and oil. Our four basin model delivered outstanding results in each and every asset with multiple catalysts as we look ahead to our 2018 budget and beyond. The momentum from our U.S. resource plays is undeniable and our volumes mix is now starting to reflect our capital allocation shift to these higher margin, lower cost barrels. Our developing story of margin expansion and the associated cash flows give us confidence that we can deliver the same discipline in 2018. We continue to garner more performance data and see material improvements across our basins with emerging stories such as Hector in the Bakken, Atascosa in the Eagle Ford – signaling that competition for our discretionary capex is broader, more diverse and more intense than it ever has been. Along those lines, you should expect our capital allocation to remain a dynamic, real time effort as we continually optimize across our four basins, leverage learnings and respond to performance trends as well as the macro environment. Our drive for maximizing returns is neither static nor limited to an annual budget cycle.

And longer term, we have continued to lower the “breakeven price” for our benchmark 2017 to 2021 production CAGR’s from $55 WTI originally, to low 50’s to now $50 WTI. A true demonstration of the potential of our transformed portfolio and we now have line of sight on cash flow yield in our five year benchmark case even at a flat $50 WTI deck.

At the heart of it all are our dedicated employees whose commitment and innovation has only been sharpened by these dynamic times.

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