Helmerich & Payne
Fiscal Second Quarter 2023 Earnings Call Transcript
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Operator: Good day, everyone, and welcome to today's Helmerich & Payne Fiscal Second Quarter Earnings call. At this time, all participants are in a listen-only mode. Later, you will have the opportunity to ask questions during the question-and-answer session. You may register to ask a question at any time by pressing star (*) one (1) on your touchtone phone. Please note this call is being recorded and I will be standing by should you need any assistance. It is now my pleasure to turn today's call over to Dave Wilson. Please, go ahead.

Dave Wilson: Thank you, Ashley, and welcome, everyone, to Helmerich & Payne's conference call and webcast for the second quarter of fiscal year 2023. With us today are John Lindsay, President and CEO; and Mark Smith, Senior Vice President and CFO. Both John and Mark will be sharing some comments with us, after which we'll open the call for questions. Before we begin our prepared remarks, I'll remind everyone that this call will include forward-looking statements as defined under securities laws. Such statements are based on current information and management's expectations as of this date and are not guarantees of future performance. Forward-looking statements involve certain risks, uncertainties, and assumptions that are difficult to predict. As such, our outcomes and results could differ materially. You can learn more about these risks in our annual report on Form 10-K, our quarterly reports on Form 10-Q, and our other SEC filings. You should not place undue reliance on forward-looking statements and we undertake no obligation to publicly update these forward-looking statements. We will also be making reference to certain non-GAAP financial measures, such as segment operating income, direct margin, and other operating statistics. You'll find the GAAP reconciliation comments and calculations in yesterday's press release. With that said, I'll turn the call over to John Lindsay.

John Lindsay: Thank you, Dave. Good morning, everyone, and thank you again for joining us today. H&P delivered another outstanding quarter and executed on several strategic objectives. On our Q2 earnings call last year, we announced the goal to achieve direct margins of 50% in our North America Solutions segment, as the pathway to generating an annualized return above our cost of capital. I'm pleased to report that we have achieved that margin goal with the second fiscal quarter results. Reaching this milestone enabled us to realize annualized mid-teens return on invested capital this fiscal year, which is the first time we have achieved a double-digit return since the 2014 upcycle. Our focus now turns to maintaining this progress in a challenging market environment. Our super-spec FlexRig utilization remains high and we are committed to this level of financial return to maintain economically sustainable operations, which is in the best interest of all our stakeholders.

Political and economic uncertainty has plagued the global crude oil market over the past few quarters and the U.S. natural gas market has been particularly weak due to excess supply following a relatively warm winter and offline LNG takeaway capacity, both of which should be short-term transitory issues. Still volatility in both commodity markets seems to have fostered an atmosphere of pessimism surrounding the industry, which we believe is a short-term challenge and could reverse itself over the second half of 2023. It is during times like these that it's good to remind ourselves how critical abundant, cost-effective, and secure energy is to sustaining security in the broader global economy.

We remain optimistic about the long-term energy fundamentals, which favor a growing global demand for natural gas as a more environmentally friendly energy source in the future and that will require more drilling to meet supply needs. Nonetheless, softness in natural gas pricing in the U.S. has had a dampening effect on current rig activity and is contributing to an increased level of contractual churn in the market, not only in terms of number of rigs, but also the increased idle time between contracts. A portion of this softening activity can also be attributable to our customer's fiscal prudence with regard to budgets and the return focus they are pursuing. These factors, in combination with our focus on pricing in order to preserve a return profile that aligns with our cost of capital, is partially responsible for the reduction in our active rig count exiting the March quarter and necessitates a lower reset of our forward rig count projections.

As we talked with some investors, they voiced concerns about an impending downturn due to idle rig capacity and the historical results related to pricing. My experience over the past two decades indicates that it isn't unusual to see rig count volatility within an upcycle. I don't ever recall an upcycle that was straight up and to the right. Additionally, super-spec rig effective utilization is above 90%, which historically has created a favorable pricing environment for us. To add some color to our activity decline, a majority of it is stemming from the weakness in natural gas prices, and it's important to remember that lowering our rates would not have kept those rigs working regardless. Now, there were a handful of rigs that were released over pricing, but those were in the minority and there were about the same number that were released in the normal churn as customers were done with the rig line mostly related to budgetary reasons. We expect this lull on activity to be short-term and should correct itself over time.

While much of the recent turbulence in rig activity has been related to natural gas, we also remain optimistic about the longer-term fundamentals for crude oil and believe it will be a persistent driver for rig demand. With nearly 80% of the U.S. land rigs directed towards crude oil drilling and with current prices above the $70 per barrel range, our expectation is there should be strength in the oil drilling market. With the current outlook from many of our customers, we expect an improving rig count in the second half of the calendar year and like the last three years, we expect a buying season in calendar Q4.

In addition to rig activity and pricing, managing costs and achieving higher levels of drilling performance also impact our ultimate returns. By investing in the FlexRig fleet, technology, people, and processes, we are able to consistently deliver the outcomes our customers desire. We continue to develop new commercial models that not only remunerate us for the value we create, but also expand collaborative efforts between H&P and its customers. This has not happened overnight as we began developing the new commercial model construct in 2019 and today 45% of our rigs are using some form of a performance-based contract.

H&P has spent the last 20 years investing in the FlexRig fleet to drive improving well cycle performance and reliability for customers. These investments over the last five years have focused on converting the fleet to super-spec capacity, which is now at 231 rigs in the U.S. In addition, we invested in multiple software technologies that are helping us to drive rig automation as well as more accurately placed in higher quality wellbores.

Let me provide some examples of the performance improvements and the lateral length increases since 2014. The average well depth drilled by FlexRig has increased by 5,000 feet to over 20,000 feet with the average lateral doubling to over 10,000 feet. Simultaneously, while drilling longer laterals, working with our customers, we have also reduced well cycle times by roughly 25% from 22 days to an average of 16 days per well. These well cycle time improvements mean rigs are working more efficiently, but it also means rigs are working harder, and this translates into higher costs for expendables, maintenance, capital, and labor. Mark will discuss costs in greater detail during his remarks but let me point out that our rig cost per day has increased from $12,500 a day in 2014 to $18,000 a day today, and that is a driver for revenues needing to be in the mid-$30,000 a day range. Maintaining a focus on our fiscal plan to ensure that we can achieve sustainable returns on invested capital is what will enable H&P to remain a viable partner to future success of our customers.

Now, shifting to the international front, H&P's potential for longer-term growth prospects remains in focus. During the quarter, we moved our first super-spec FlexRig into our Middle East hub and we have sent another to Australia. While initially small in terms of rig count, these two projects are important to our international strategy, and we believe they will open doors to more opportunities. Along those lines, we still plan to export additional super-spec rigs to the Middle East during the back half of the calendar year after undergoing conversions that fit to specific needs for operations in the region. Operations in Argentina and Colombia have remained relatively steady and provided solid financial contributions.

We have executed on our shareholder focused capital allocation strategy and since October of this fiscal year, we have returned approximately $250 million to date in capital via regular and supplemental dividends and share buybacks. Furthermore, we still have ample cash available to complete our announced dividend plans as well as conduct additional repurchases or take advantage of other investment opportunities.

In closing, over the past few months, I have seen H&P working more collaboratively with customers than any time in my career. The outcomes we are jointly pursuing is economic value-added productivity using new commercial models rather than just a focus on the day rate. That is due in large part to our customers realizing the near and long-term benefits of having H&P as their drilling solution partner. All of this is possible by H&P employees utilizing our rig assets and technologies to consistently deliver desired outcomes for our customers. Now, I'll turn the call over to Mark.

Mark Smith: Thanks, John. Today, I will review our fiscal second quarter 2023 operating results, provide guidance for the third quarter, update full fiscal year 2023 guidance as appropriate and comment on our financial position.

Let me start with highlights for the recently completed second quarter, ended March 31, 2023. The company generated quarterly revenues of $769 million versus $720 million from the previous quarter. As expected, the quarterly increase in revenue was due primarily to focused efforts to move our North America fleet pricing higher. Total direct operating costs were $450 million for the second quarter versus $429 million for the previous quarter. The sequential increase is attributable to higher average active per rig costs in North America.

General and administrative expenses were approximately $53 million for the second quarter, slightly higher than expected due to miscellaneous information technology and professional services costs. During the second quarter, we recognized a gain of approximately $40 million, primarily related to the fair market value of our equity investments, which is reported as a part of gain on investment securities in our consolidated statement of operations. Our Q2 effective tax rate was approximately 24%, which is within our previously guided range.

To summarize this quarter's results, H&P earned a profit of $1.55 per diluted share versus $0.91 in the previous quarter. As highlighted in our press release, second quarter earnings per share were positively impacted by a net $0.29 gain per share, select items consisting of the aforementioned gain on investment securities. Absent these select items, adjusted diluted earnings per share were $1.26 in the second fiscal quarter versus an adjusted $1.11 during the first fiscal quarter.

Capital expenditures for the second quarter of fiscal 2023 were $85 million, which was $11 million less than the previous quarter capex. I will comment later on a revised fiscal 2023 capital expenditure guidance.

H&P generated approximately $141 million in operating cash flow during the second quarter of 2023, which is inclusive of $114 million in the second quarter outflows for cash tax payments and is in line with our expectations. I'll address the company's cash position later in my remarks.

Turning to our three segments, beginning with the North America Solutions segment. We averaged 183 contracted rigs during the second quarter, up from an average of 180 rigs in the fiscal Q1. We exited the second fiscal quarter with 179 contracted rigs, which was less than our guidance expectations. As mentioned earlier, revenues increased sequentially by $49 million due to higher average pricing. Segment direct margin was $296 million, which was at the higher end of our January guidance and sequentially higher than the previous quarter, which came in at $260 million. Performance contracts were up to about 43% of total contracted rigs in the second quarter. In addition, reactivation costs of $5.2 million were incurred during Q2 compared to $8.6 million in the prior quarter. This includes three walking rig conversions, which were committed prior to entering the second quarter and completes the six walking rig conversions we had planned for the U.S. market in fiscal 2023. Total segment expenses, excluding recommissioning costs and excluding reimbursables, increased to $18,000 per day in the second quarter from $16,800 per day in the first quarter.

Looking back over the past two years, our increases in cost from $16,000 per day at the end of fiscal 2021 to $18,000 today are primarily due to a few factors. First, as discussed on previous calls, we increased field labor related rates in December 2021 and September 2022 for a total of about $1,300 per day. As a reminder, labor is approximately 70% to 75% of daily operating expenses and the forward outlook for labor rates is stable. Second, as John alluded to in his remarks, we are seeing an increase in consumption of materials and supplies inventory items due to the increased operational intensity of our rigs. Recent data shows we have gone from drilling 800 feet per day per rig in 2017 to 1,250 feet today, which is driving our rigs to work harder than ever before, thus consuming more materials and supplies. Finally, as performance contract and technology revenues increased, additional costs are incurred to achieve those added revenue streams.

Looking ahead to the third quarter of fiscal 2023 for North America Solutions, although we exited fiscal Q2 with 179 rigs working, we have since seen several April releases and as of today's call we have 169 rigs contracted, 167 of which are super-spec rigs, and we project that by the end of the third fiscal quarter, we will have between 155 and 160 contracted rigs. Last quarter we peaked at 185 working super-spec rigs and with 18 recently idled, we are at approximately 90% utilization of the recently active fleet. As John mentioned, natural gas price declines this calendar year coupled with macroeconomic uncertainties have resulted in current moderated rig demand. Different from previous cycles, H&P is maintaining focus on pricing and idling rigs instead of reducing pricing and growing market share. This is necessary to maintain our recently achieved double-digit annualized return on invested capital relative to our cost of capital of over 10%. Moreover, as rig costs typically are only approximately 15% or less of the total cost of a customer's well, reducing pricing to keep a rig working will not likely guarantee that rig continues to work beyond the immediate term. Instead, individual price reductions would put downward pressure on pricing for the remainder of our active fleet, which would be return destructive to the company, particularly given the historical long elapsed timeline to boost pricing back up again.

In summary, we are willing to sacrifice some near-term cash flow generation related to activity drops versus risking larger cash flow degradation related to pricing. Our current revenue backlog from our North America Solutions fleet is roughly $1.1 billion for rigs under term contract. As of today, approximately 60% of the U.S. active fleet is on a term contract. Our average spot revenue per day is currently in the high $30,000 level inclusive of performance bonus earned and technology utilization compared to the Q2 overall average revenue per day of approximately $36,300.

In the North American Solutions segment, we expect direct margins in fiscal Q3 to range between $265 million to $285 million. Notwithstanding 2022 inflation now included in our average cost inventory on the balance sheet, we believe our current materials and supplies unit costs will be relatively stable for the remainder of fiscal 2023, but as mentioned previously, we are experiencing higher inventory consumption rates, which we expect will continue in Q3. We currently expect third quarter per day cost to remain flat at approximately $18,000 per day. However, as we idle more rigs in the third quarter, our overhead absorption rate will be spread over a smaller number of active rigs, which may push cost slightly higher for active rigs through the second half of the fiscal ’23. As John mentioned, when we look beyond fiscal Q3, the calendar yearend, we believe more rigs will be put back to work, reversing some of the near-term effects of such overhead absorption on daily cost.

Next, to our International Solutions segment. International Solutions business activity ended the second fiscal quarter with 14 rigs drilling in the super-spec rig mobilizing to Australia. We added a rig in Bahrain as expected, which brings our working rig count to two of the three in that country. International results were in line with previous guidance. As we look towards the third quarter of fiscal ’23 for international, we anticipate idling one rig in Argentina that completed its term contract and one in Colombia as that customer assesses the recently drilled well and determines the next steps. Our sales team is working on opportunities to put both of these idle rigs back to work in the near to mid-term. Expenses associated with setting up our Middle East hub and preparing rigs to mobilize abroad affected results in Q2 and are expected to continue in Q3. In the third quarter, we expect to earn $4 million to $7 million in direct margin aside from any foreign exchange impacts.

Finally, to our offshore Gulf of Mexico segment, we had four of our seven offshore platform rigs contracted, and we have active management contracts on three customer-owned rigs, two of which are on active rate. The offshore segment generated a direct margin of $9.3 million during the quarter, which was in line with our estimate and flat sequentially. As we look toward the third quarter of fiscal ’23 for the offshore Gulf of Mexico segment, one of our platform rigs is beginning demobilization as the customer has reached the end of its multi-year drilling program. This rig will be on some form of demobilization rate until it arrives at the shipyard, which is anticipated to be in mid-August. We expect offshore will generate between $5.5 million to $7.5 million of direct margin.

Now, let me look forward to update full fiscal year 2023 guidance as appropriate. Capital expenditures for the full fiscal ’23 year are now expected to range between $400 million to $450 million, decreasing the midpoint $25 million from prior guidance. Although we expect the timing of our capex spend to vary from quarter-to-quarter, supply chain delays have continued to push some maintenance capex out in our planning horizon. Our expectations for general and administrative expenses for the full fiscal year increased to $205 million. The additional costs are primarily due to increased professional services fees and information technology expenditures. We are still estimating our annual effective tax rate to be in the range of 23% to 28% with the variance above U.S. statutory rate of 21% attributive to permanent both the tax differences and state and foreign income taxes.

In Q2, we paid cash tax of approximately $114 million, which is up from $4 million in Q1. For the full fiscal year, we're now anticipating a cash tax range of $175 million to $225 million. The midpoint of this revised range is $15 million lower than the prior quarter guidance midpoint due to the previously mentioned the lower rig activity expectations.

Now, looking at our financial position. Helmerich & Payne had cash and short-term investments of approximately $245 million on March 31 versus an equivalent $348 million at December 31, 2022. The sequential decreased cash balance is largely attributable to our fiscal Q2 share repurchases.

Regarding cash balances and taking into account the recent developments discussed today and the implications those have had on forecasted activity, cash taxes and capex, we have updated our estimates for our fiscal 2023 yearend cash balance. At the beginning of this fiscal year, we've provided a range of $430 million to $490 million. Our revised cash range at fiscal yearend is now $340 million to $380 million, which largely reflects the overall impact of the share repurchases to date. Including availability under our revolving credit facility, our liquidity remains relatively flat at approximately $1 billion. Approximately 2.5 million shares were repurchased in fiscal Q2 for approximately $107 million. Fiscal 2023 repurchases have totaled about 3.4 million shares thus far for approximately $146 million. These share repurchases augment our longstanding base dividend and fiscal 2023 supplemental dividend. Each of these items, stock repurchases and the base and supplemental dividends, encompassed the new capital allocation and shareholder return model that we announced in October at the beginning of this fiscal year. Pricing focus in North America combined with our capital allocation execution underscores our focus to not only increase the financial returns of the company, but also the cash returns provided to shareholders.

That concludes our prepared comments for the second fiscal quarter and let me now turn the call over to Ashley for questions.

Operator: Certainly. At this time, if you would like to ask a question, please press star (*) one (1) on your touchtone phone. You may withdraw your question at any time by pressing the pound (#) key. Once again, that is star (*) and one (1), and we will take our first question from David Smith with Pickering Energy. Please, go ahead.

David Smith: Hey, good morning. Thank you for taking my questions.

John Lindsay: Good morning, Dave.

David Smith: So, congratulations on getting to the 50% margin target that you've set, and an extra congratulations on showing the disciplined leadership to keep those margins. I have kind of a two-part question. Thinking about your exit rate for your lower 48 count last December versus your projection for the June exit, I understand natural gas activity factors in there. I wanted to know if you could give us any color on the customer mix of rigs being dropped, and then secondly, if you could give us an update on what portion of your fleet is on performance-based contracts and if you see that mix changing from last December to the June exit.

John Lindsay: Sure, David. Yes, the mix on the releases of the rigs we've had released thus far, approximately 70% are private companies, and as we – what was the second part of your question? Oh, yes, performance contract. Yes, we're at 45% of the current working fleet is under some sort of a performance contract or another.

Mark Smith: David, this is Mark. We've seen that take up a bit since the prior quarter, we're around 40%, so some gradual increase up to 45% as our sales force continues to work with customers for ways to get our revenue per day to acceptable level for our return generations required, while also getting the customers the right KPIs they need to derive value on their side.

David Smith: Appreciate that color, and a quick follow-up, if I may. I don't want to be shortsighted, but thinking about capital allocation, to the extent that international growth capex could be discretionary, how do you kind of see the opportunity to deploy capital for international growth compared to buying back your stock at these levels? Maybe that's just a – you can clearly do both.?

John Lindsay: Yes, that's right, and I would lean toward all of the above. I think we've got the balance sheet to do both. Obviously, we would love to do more internationally, as you've seen it grip – it's a pretty slow growth, but we do think there's opportunities and again, hopefully, we'll be moving some additional assets there in the back half of this year, but we've talked a lot about our share buybacks and looking at it from an opportunistic perspective and there's obviously a lot of opportunity. Anything you would add?

Mark Smith: No.

John Lindsay: Okay.

David Smith: Great. Thank you so much.

John Lindsay: Thanks, David.

Operator: We'll take our next question from Derek Podhaizer with Barclays. Please, go ahead.

Derek Podhaizer: Hey, guys. Good morning. Going back to the rig decline, the exit, about 20 to 25 rigs down. Do you know, is that industry rigs coming off? I know it's your rig count, but are some of those E&Ps picking up lower price rigs or lower tier rigs? Just want to know if that's an industry rig count drop as well or if you're seeing some offsets with some adds from those E&P that you're dropping your rigs with.

John Lindsay: Yes. Derek, I don't have a clear insight into all the comparisons, but I'm pretty certain that on the natural gas front, those rigs are not being replaced. I mean, those rigs are being – our rigs, and I'm sure other competitor rigs, are being released as a result of low gas prices and so I don't think that's surprising. I'm sure there are other instances where we are being replaced by a lower cost per day rig, and I think that's really the key thing to focus on there is that it may be a lower cost per day, but it's not a lower cost of the overall project, and fortunately, we have been able to maintain a level of pricing through the performance contract construct, because in a traditional fashion, all you really have to negotiate with a customer with is the day rate, if that's all you're pricing your value on. So, there's a great opportunity in working with customers to drive additional value and creating a win-win through that performance-based contract. So, we're getting a lot of traction. It's been very positive. Obviously, we do still have traditional day rate contracts and we have great performance with those customers as well, but it is a different way to approach the business.

Derek Podhaizer: Understood, and I know the last question, you said that 70% of those rig drops were private. Can you break out the gas versus private? Because I know on the last call, you talked about, I think, 28 rigs being gas, a little over half of those were on term contracts, so I would suspect those were safe. So, maybe just a little color on the mix between gas versus oil rig drops.

Mark Smith: Derek, this is Mark. We can get back with you on details there, but suffice it to say that the predominance of the privates for us were also weighted towards those gas basins, but we can follow up with more details.

Derek Podhaizer: Got it. Okay, and I'll just sneak one more in. Given that you've lowered your activity estimates for the rest of the year, does this free up some of the equipment to potentially go over to the Middle East or even down into Australia, maybe more than you thought of, maybe not for this year, but maybe your fiscal 2024? Have you started to have conversations around maybe increasing the rig that you send over?

John Lindsay: We really haven't at this point, Derek. Again, our belief is the second half of the year, particularly Q4, we expect not the same type of response, but a similar response where it is that buying season. The difference, of course, this go-around, the past three years, we've been reactivating rigs out of long-term stack and so now we'll be reactivating rigs that have been idled for a very short period of time, so it'll be very low cost to reactivate those rigs and get those rigs back working. So, it's really hard to say at this point in time. I mean, it does obviously take a lot of pressure out of the supply chain, because there have been supply chain challenges, but over time, clearly, our goal would be to move more of our super-spec capacity to international markets as those opportunities arise.

Derek Podhaizer: Great. Appreciate the color. I'll turn it back.

Operator: We'll take our next question from Don Crist with Rice Johnson. Please, go ahead.

Don Crist: Good morning, gentlemen. Thanks for letting me in. I wanted to focus on your comments about the rig count kind of coming back up or increasing in the back half of the year, and I wanted to kind of get a little bit more color around there, but that kind of leads me to believe that the guidance that you gave for end of the calendar second quarter of 155 to 160 rigs in the U.S. kind of being a bottom. Am I thinking about that correctly and is that the kind of conversations you're having with your customers that they're expected to pick up rigs in the third quarter and going into the fourth quarter calendar quarters?

John Lindsay: I think that's a good way to look at it. That's what our hope is. We are having conversations with some customers about some June opportunities. You've probably heard me say before, it's difficult to see out much past a quarter, but we are having some conversations and so that leads us to believe that we will start picking some rigs back up, and again, hopefully, that is the bottom at that point.

Don Crist: Okay, and just one further one from me. The rigs that you're stacking out today, are they moving around to other basins? Are you stacking them in basin with hopes that this is only a transitory event and those rigs would go back to work in those basins as we progress through the year and go into '24?

Mark Smith: Don, this is Mark. When we finish a rig working and it starts to idle out, the customer pays for the mobilization and that goes to the yard in the district or the region where it is, and when we are idling those rigs today, those costs are really de minimis, I'd say, compared to what we might have done to idle a rig, for example, comparatively in 2020, because then we were doing a lot of preservation work and preparing those for a long idle period. Today, we're putting them in the yard and having them just sit, ready to roll for when they may be able to go back to work in the next three to six months, so that on the other end, the reactivation cost is also minimal and it's in the basin where it was and can go back to work quickly.

John Lindsay: Yes, and I'll just add to that, and we really – as you look at the basins that we're in and our position in the basins, we like the position of the rigs. We're the number one provider in the Permian, the Eagle Ford, the Haynesville. We've got great positions in the other basins. So, as Mark said, they'll be there well-positioned to pick up right where they left off.

Don Crist: I appreciate you letting me in. Thank you.

John Lindsay: Thank you, Don.

Operator: We will take our next question from Keith Mackey with RBC Capital Markets. Please, go ahead.

Keith Mackey: Hi, good morning and thanks for taking the questions. Just the first one on the performance-based contracts, understand it's 45% or 43% of the current fleet. Is there a way to quantify the benefit you get from the performance-based contracts? You talked about the footage per day increases. Is there a way to quantify exactly – have you been paid commensurately for that progress relative to just what's happened in the market?

John Lindsay: Yes, we do have some metrics around that. I think one of the ways to think about it is, as you think about just a base, if you will – a base day rate and then being able to look at a performance profile that a customer wants to hit, not just drilling performance, but also wellbore placement, wellbore quality, as an example, footage in the lateral, there's a lot of different ways customers look at what it is they're trying to achieve and so there's definitely a premium, but in some cases, ultimately, what we're doing is we're trying to get our rates at that mid-30s, like I had mentioned, that 50% gross margin, which is delivering that mid-teens ROIC. So, that's ultimately the end goal and as I've said before, rather than only negotiating on a day rate basis, and the answer is either yes or no, you've got some optionality on the value proposition that we're looking into. So, it's a really valuable way to create this win-win with us and our customer, because let's face it, at the end of the day, our day rate – our total revenue on the course of drilling well isn't a huge needle mover on the total cost of the well. The real benefits are saving days on well and improving wellbore quality placement, reliability, quality, all those things are the drivers that we're spending a lot of time talking with our customers about.

Keith Mackey: Got it, and if I could just follow up on your comments about getting the return on capital to exceed cost of capital, and that being roughly around where things are now in terms of rates and pricing. Can you just maybe give us a bit of commentary on sort of where you think we are in the cycle, given that dynamic, our leading rates materially above your cost of capital, are they just catching up to where it should be and ultimately, what you think your – what will happen to your longer-term cost of capital given the trajectory of the industry and what that ultimately means for the rates you need to make in the current environment in the years ahead?

John Lindsay: Yes, that's a great question, Keith. We've been saying this now for a couple of quarters, but we're really not focused on that leading edge price. What we're really focused on is getting to that – the – all the rigs to that average that we've talked about, and obviously, it's extremely important for us as an organization to be able to have that mid-teens type return. Again, we haven't been there since 2014 and we've made a lot of investments in the company, in our people, on our rigs and technologies, and we're doing that because we're doing our dead level best to partner with our customers and try to deliver as much value as possible for them and with them and so that's what's driving that; and again, we've talked about the cost side of the equation. Our costs are up over $5,000 a day since 2014. So, that's really ultimately the driver for us and, obviously, let's face it, we've got to have returns that are above our cost of capital or we're not an investible company. So, that's a big part of the way we're looking at this. Again, I've mentioned in the comment that occasionally we'll have an investor visit with us and say something along the lines of the current downturn. It's like – well, this is not a downturn. This is a very normal part of the cycle within a longer-term upcycle. You can look back at different periods over the last 20 years and you can see that for yourself. There's a lot of volatility in rig activity. So, again we feel good about the position, but that's our focus. It's focused on the returns over market share.

Keith Mackey: That's it for me. Thanks for the color.

John Lindsay: Thank you.

Operator: This concludes our Q&A section. I'll turn the call back over to John Lindsay for closing remarks.

John Lindsay: Thank you, Ashley. Listen, thanks again for joining us today. I know there's a lot of calls and it's a really busy day, so thanks for joining us. We remain optimistic about the future, really pleased with the momentum that we have as an organization. We recognize the headwinds and the challenges, but I don't think anybody's better positioned than H&P to perform through this cycle. As we've said multiple times today, we're focused on our returns, creating returns over market share. We think we're really well-positioned with great technology and people and solutions to really provide great outcomes for our customers. So, thanks again for your time and have a great day.

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