3Q18 Earnings Conference Call
Edited Transcript

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This transcript has been edited by Chevron Corporation. It is generally consistent with the original conference call transcript. For a replay of the earnings call for the third quarter of 2018, please listen to the webcast presentation posted on chevron.com under the headings "Investors," "Events & Presentations."

Transcript

Operator:
Good morning. My name is Jonathan, and I will be your conference facilitator today. Welcome to Chevron's third-quarter 2018 earnings conference call. (Operator Instructions). As a reminder, this conference is being recorded.

I will now turn the call over to the Vice President and Chief Financial Officer of Chevron Corporation, Ms. Pat Yarrington. Please go ahead.

Pat Yarrington (Vice President and Chief Financial Officer, Chevron Corporation):
Hi. Good morning, and thank you, Jonathan. Welcome to Chevron's third-quarter earnings conference call and webcast. On the call with me today are Pierre Breber, Executive Vice President, Downstream and Chemicals; and Wayne Borduin, General Manager of Investor Relations. We will refer to the slides that are available on Chevron's website.

But before I get started, please be reminded that this presentation contains estimates, projections, and other forward-looking statements. And we ask that you review the cautionary statement shown on slide 2.

Turning now slide 3, an overview of our financial performance. The Company's third-quarter earnings were $4 billion, or $2.11 per diluted share. This is more than $2 billion higher than the same period a year ago, and this is the highest recorded earnings per share since third-quarter 2014. The Company's year-to-date earnings were $11.1 billion or $5.79 per diluted share. This was $5 billion higher than the same period a year ago.

The quarter included the unfavorable impacts of a project write-off, an impairment, and a nonrecurring contract settlement which totaled $930 million. These were partially offset by a $350 million gain on the sale of our Southern African refining and marketing assets.

Foreign exchange losses for the quarter were $51 million. A reconciliation of special items, foreign exchange, and other non-GAAP measures can be found in the appendix to this presentation.

Excluding these special items and foreign exchange impacts, earnings totaled $4.7 billion or $2.44 per share. Cash flow from operations for the quarter was $9.6 billion. Excluding working capital effects, cash flow from operations was $9.2 billion. Cash flow from operations continued to grow in the third quarter, and was the highest it has been in nearly 5 years, back when Brent crude prices were averaging about $110 per barrel. Year-to-date cash flow from operations totaled $21.5 billion, about $7 billion more than a year ago.

At quarter-end, debt balances stood at approximately $36 billion, giving us a debt ratio of 19%. During the third quarter, we paid $2.1 billion in dividends, and we repurchased $750 million of our shares during the quarter. We currently yield 4%.

Turning to slide 4. Our third-quarter cash flow from operations, excluding working capital effects, increased to $9.2 billion, reflecting higher realizations and growing volumes in our US and international upstream. On a year-to-date basis, cash flow from operations, excluding working capital, totaled $23.3 billion. This included $600 million in discretionary US pension contributions, $800 million in deferred income taxes, and affiliate dividends approximately $2.5 billion less than equity affiliate earnings.

Cash capital expenditures for the quarter were $3.6 billion, and $9.8 billion year-to-date. The result…free cash flow, excluding working capital effects, of $5.6 billion for the quarter and $13.5 billion year-to-date. Through the first three quarters of the year, normalized for $60 Brent, we are on track to deliver the $14 billion cash generation guidance communicated at the Analyst Meeting in March.

Turning now to slide 5, a view of our sources and uses of cash through the quarter. We are delivering on all four of our financial priorities. We maintained our commitment to competitive dividend growth by paying out $2.1 billion in cash dividends to our shareholders. We continue to fund our highest-return projects at a reasonable pace. We further strengthened our balance sheet and paid down debt by $2.4 billion, lowering our debt ratio to 19%. And finally, we commenced our share repurchase program in the third quarter and returned $750 million of surplus cash to shareholders.

Now on slide 6, I'd like to provide an update on our portfolio optimization efforts. Through the third quarter, we received before-tax asset sale proceeds of $1.9 billion, including the divestment of our Southern African refining and marketing business. Most recently, we signed sale and purchase agreements including the sale of our 12% non-operated interest in the Danish Underground Consortium and the sale of our 40% interest in the Rosebank project, West of Shetland in the UK.

In addition, we continue the process of marketing our UK Central North Sea assets. As with all divestments, we are focused on generating good value from any transaction. The progress we have made year-to-date on portfolio optimization puts us on track to generate $5 billion to $10 billion in asset sale proceeds over the 2018 to 2020 time period, as we guided back in March.

Turning to slide 7. Third-quarter 2018 after-tax earnings of $4 billion were approximately 2 times that of third-quarter 2017. Special items reduced earnings by approximately $1 billion between periods.

In the current period, special items included a gain on the sale of Southern African R&M assets, the write-off of the Tigris project in the US Gulf of Mexico, an impairment on an asset held for sale, and a nonrecurring contractual settlement, all of which netted to a negative $580 million.

In third-quarter 2017, special items included a gain on the sale of Canadian R&M assets, less a project write-off, for a net positive impact of $455 million. Foreign exchange impacts increased earnings by $61 million between periods.

Upstream earnings, excluding special items and foreign exchange, increased by almost $3.5 billion between the periods, or about 5 times, mainly on improved realizations and higher liftings. Oil prices were approximately 45% higher in the current period than a year ago.

Downstream results, excluding special items and foreign exchange, decreased by about $100 million. This reflected lower margins in Asia and in the US, along with forgone contributions from our Canadian downstream assets which were sold. Favorable timing effects and higher earnings from CPChem were partially offsetting. The variance in the other segment was primarily the result of higher corporate tax items and interest expense.

Turning to slide 8, this compares results for third-quarter 2018 with second-quarter 2018. Third-quarter results were approximately $600 million higher than second quarter. Third-quarter special items, as detailed previously, when compared to second quarter's nonrecurring receivable write-down, resulted in a net negative variance between the quarters of $310 million. Of about equal size was an adverse swing in foreign exchange impacts between the periods.

Upstream results, excluding special items and foreign exchange, increased by $1 billion between the quarters due to higher liftings and improved realizations. During the quarter, we were in an over-lifted position. But on a year-to-date basis, we are modestly under-lifted.

Downstream earnings, excluding special items and foreign exchange, improved by almost $240 million, reflecting lower operating expenses, particularly those associated with the second-quarter turnaround at the Pascagoula refinery. Favorable timing effects were also evident between periods.

Turning to slide 9. Third-quarter production was 2.96 million barrels a day, our highest ever production for a quarter. This moved our year-to-date production to 2.88 million barrels a day. Excluding the impact of 2018 asset sales, which is the middle bar, our year-to-date production growth through the third quarter was 6% higher than the daily average production for full-year 2017.

As Jay mentioned on our last-quarter call, we had planned turnaround activity across multiple locations in the third quarter. The production impact from these turnarounds was 103,000 barrels per day. 2018 asset sales impacted third-quarter production by 18,000 barrels a day, and impacted year-to-date production by 12,000 barrels per day.

At year-end, we expect to be at the top of our original guidance range: approximately 7% growth, excluding the impact of asset sales. And this is even without normalizing for the impact of current prices on production sharing contracts.

Turning to slide 10. Third-quarter 2018 production was 2.96 million barrels per day, an increase of 239,000 barrels a day or 9% from third-quarter 2017. Major capital projects increased production by 237,000 barrels per day as we continued to ramp up multiple projects, most significantly Wheatstone, Gorgon, and Hebron. Shale and tight production increased 155,000 barrels per day, primarily due to growth in the Midland and Delaware Basins in the Permian, where production grew by 80% from a year ago.

Base declines, net of production from new wells, such as those in the US Gulf of Mexico and Nigeria, were 6,000 barrels a day. Major turnarounds, along with planned and unplanned downtime, reduced production by 59,000 barrels per day between the periods. Entitlement effects reduced production by 41,000 barrels a day, due primarily to rising prices between the periods. The impact of 2017 and 2018 asset sales reduced production by 31,000 barrels a day between the periods.

Now on slide 11, Gorgon and Wheatstone continued to operate very well. Combined, these plants averaged 379,000 barrels a day of production during the quarter. This is a 35% increase over the previous quarter. We had two planned maintenance activities on Wheatstone during the quarter: a scheduled compressor overhaul on train 1, and the start-up strainer removal on train 2. These reduced production by approximately 21,000 barrels a day, on average, over the quarter.

We are finalizing the commissioning of the Wheatstone domestic gas plant, and expect first sales in first-quarter 2019. For this gas, production and sales activity will be dependent on local demand. With all five Australian LNG trains running reliably, we're focusing on finding opportunities to incrementally add production and enhance reliability.

Turning to the Permian on slide 12. Permian shale and tight production in the third quarter was 338,000 barrels per day, representing an increase of 150,000 barrels per day. Let me say it again: this is up 80% relative to the same quarter last year. As many of you will realize, that's the equivalent of adding a midsized Permian pure play E&P company in a matter of months.

In our operated Permian acreage, where we hold 100% of the working interest, we had an average of 20 rigs in operation during the quarter. We also had 21 non-operated rigs working on our acreage, which equates to approximately 7 net rigs Chevron's share. As Jay discussed on the last earnings call, we remain focused on returns, capital efficiency, and operational discipline. Within this framework, our production levels are trending about one year ahead of the guidance we gave in March.

I'll now pass it on to Pierre, who can give an update on our Downstream and Chemicals business.

Pierre Breber (Executive Vice President, Downstream & Chemicals, Chevron Corporation):
Thanks, Pat. We have a tightly integrated and profitable Downstream and Chemicals business. Slide 13 shows that Chevron's Downstream has consistently led our peer group in earnings per barrel. And during the past five years, our adjusted return on capital employed has averaged over 15%.

Our fuels businesses are focused in the best markets in the US and Asia; in petrochemicals, we are feedstock-advantaged, heavily weighted to ethane; and we are the only major integrated with wholly owned lubricants and additives businesses. Looking forward, our objective is to grow earnings across our feedstock-to-customer value chains and target investments to lead the industry in returns.

Now let me address IMO 2020. As a reminder, new International Maritime Organization regulations will reduce the sulfur emissions from bunker fuels starting in 2020. Although there are a lot of unknowns and uncertainties with how markets will react, most agree that complex refiners should benefit as demand increases for marine gas oil.

Slide 14 shows that Chevron's refining network has the highest complexity and the highest percentage of conversion capacity among its peer group. It is a result of high-grading our refinery portfolio over the years and investing in upgrading capability. Forward markets expect mid-distillate margins to increase post-IMO, and high sulfur fuel oil and sour crude discounts to widen. Chevron's refining network produces over 40% mid-distillates and about 5% fuel oil. And as a complex refiner, we run a high proportion of heavy sour crudes. We believe we are well positioned to benefit from IMO impacts.

We like the petrochemicals business, and have highly competitive 50-50 joint ventures in ChevronPhillips Chemical Company and GS Caltex. Slide 15 shows our major chemical projects in various stages of development. CPChem successfully started up its Gulf Coast project after a remarkable recovery from Hurricane Harvey. The ethylene plant reached full production rates two weeks after a March start up, and exceeded nameplate capacity soon after. CPChem is focused on additional de-bottlenecking opportunities.

Following its success with this project, CPChem is in the evaluation stage of a second one in the US Gulf Coast. We like the Gulf Coast because of its feedstock advantages, and expect competitive ethane supply for a long time. We are focused on developing the most capital-and cost-efficient project, one that is on the left side of the supply stack.

GSC is in front-end engineering and design for a mixed feed olefins cracker, about two-thirds naphtha and the rest refinery LPGs and off-gases. We plan to make a final investment decision next year. Estimated costs are not final, but we expect our share of the capital to be a little more than $1 billion. The fundamentals of chemicals are strong, but costs always matter. We will continue to be disciplined in how we invest in our next set of chemical projects.

In our fuels businesses, retail is an important part of a tightly integrated value chain that starts with our complex refineries. Two recent retail highlights are shown on slide 16. In Mexico, we have about 100 Chevron-branded, marketer-owned sites. Customer response has been very positive. Stations rebranded during the first half of 2018 averaged 30% higher sales through September. We've also signed access agreements for two new terminals under development. After the terminals are complete, we will have built, in a capital-light way, an additional market to integrate with our West Coast value chain.

We continue to grow our convenience store offering with now over 800 stores. As the only major with a leading c-store franchise in the US, we have an advantage in retaining and growing our relationships with retailers. Same-store sales at ExtraMile c-stores have grown 7.4% year to date, more than double the industry average.

In the digital space, we made announcements on new mobile pay partnerships in the US, and went live with a pay app in Southeast Asia. These are important efforts to speed up and simplify the fuels retailing experience.

In our Oronite additives business, we celebrated the ground breaking for our blending and shipping project in China. This facility will help us serve the growing Chinese market when it is operational in 2021.

Finally, in our lubricants business, we are codeveloping a renewable, biodegradable base oil with ultralow viscosity and ultralow volatility, important properties for OEMs as they develop engines to meet increasingly stringent fuel efficiency and environmental regulations. It's early days, but we are excited by the potential of this new product.

As shown earlier, Chevron's Downstream and Chemicals has a track record of consistent financial performance. That said, in any one quarter, refinery planned turnarounds impact our results. Through our recent investor engagements, we've heard your request for improved guidance in this area.

Slide 17 shows the average after-tax quarterly earnings impact of planned turnaround activity for the last five years for our refineries in the US and Asia. The impact is defined as shutdown expenses, plus the forgone margin from volumes not produced. Planned turnarounds are seasonal, but have a fair amount of variability in any given quarter. As a result, we believe that the best way to provide forward-looking guidance is by characterizing turnaround activity as high, if the earnings impact is expected to be greater than $200 million; low, if it's expected to be below $100 million; and medium, in between. During 2018, the first two quarters had high turnaround activity, and the third quarter was low.

Now I'll turn it over to Pat to close out with fourth-quarter guidance and year-to-date results.

Pat Yarrington:
Looking at slide 18, just a couple of comments about expectations for the remainder of the year. We expect positive production trends to continue in the fourth quarter, fueled by sustained Permian growth and fewer planned upstream turnarounds. Downstream in contrast has a high turnaround activity planned, and this is expected to weigh on this segment's fourth-quarter earnings and cash flow.

For C&E, you'll recall that we don't budget for unanticipated inorganic spend. Through the first nine months, we have spent approximately $150 million on inorganic C&E. And we expect to spend a total of $600 million for the full year, primarily as a result of six blocks won in the Brazil licensing round. Organic C&E is running modestly above our plan, and we expect it to be approximately 5% higher than our full-year budget of $18.3 billion.

Cash flow from operations is expected to be strong in the fourth quarter. Oil prices, of course, will be the primary determinant of this outcome, and we can't predict those. While we do anticipate fewer affiliate dividends in the fourth quarter, we'll continue to benefit from further production growth, modest asset sale proceeds, and some expected additional release of working capital.

Lastly, let's revisit our year-to-date results and how they compare against commitments that we laid out earlier this year. Cash flow from operations is expanding, as anticipated, given our strong production growth, favorable market conditions, and asset reliability. Excluding the impact of asset sales, production growth is currently at 6% relative to full-year 2017, and we expect to end the year closer to a 7% year-on-year increase. Our Permian assets are performing well ahead of guidance. We continue to rationalize and optimize our portfolio, with proceeds of $1.9 billion captured year-to-date.

We're demonstrating our commitment to capital discipline and are returning cash to our shareholders. Total shareholder distributions have amounted to $7.2 billion year-to-date: $6.4 billion in dividends, and $750 million in share repurchases.

We've have had a very solid operating and financial performance so far in 2018, and we expect that performance to continue. We're seeing significant growth in cash generation due to the above-plan production growth, continuing capital and operating expense discipline, and favorable market conditions. As a result, we've been able to grow shareholder distributions and strengthen our balance sheet. We believe that Chevron offers a very attractive offering for investors, with oil price levered momentum in the upcycle, and low-cost portfolio resilience in the downcycle.

So that concludes our prepared remarks, and we're now ready to take your questions. Please keep in mind that we do have a full queue, and so please try to limit yourself to one question and one follow-up, if necessary. We will certainly do our best to get all your questions answered. Jonathan, please go ahead and open the lines.

Operator:
(Operator Instructions). Jason Gammel, Jefferies.

Jason Gammel (Jefferies):
First turn to the Permian, obviously very strong operational performance there in 3Q. And while I certainly wouldn't pro-rate the growth that you saw there moving forward, I was hoping you might be able to address some of the factors that led to such strong production growth.

Pat Yarrington:
Okay, Jason. Thanks. First of all, we have been ramping up to the 20 rigs throughout the last couple of years. And we achieved 20-rig realization in the third quarter. So that was a primary determinant. We are operating with a new basis of design, and we're finding that [the new basis of design] has been incredibly successful. We're also pursuing high-density fracs, and we're finding those to be successful as well. So there's a number of factors that have led to the overall improvement that we have seen.

Our NOJV partners [have also contributed to the strong performance]. Prices have been stronger, perhaps, than they were thinking at the beginning of the year, so the NOJV activity has risen as well.

Jason Gammel:
That's great. And maybe to take advantage of Pierre being on the call: Pierre, we've had that discussion before about your Downstream business being very high return and very high-margin, but relatively small compared to your competitors. I believe you've been quoted as saying that you may be interested in expanding your refining presence on the US Gulf Coast. Can you, if that's correct, maybe talk about some of the strategic drivers for wanting to expand there?

Pierre Breber:

Chevron

Thanks, Jason. I won't comment on media reports or speculation. But what I can say is I have, for almost as long as I've been in the job now -- over two years -- talked about the strategic rationale of a Gulf Coast refinery, for three primary reasons. The first, we're the only major company that operates one refinery in the Gulf Coast.

Second is we have a strong retail presence in Texas that we [currently] supply with [some] third-party barrels. And third is the possible integration and synergies with our advantaged position that Pat just talked about in the Permian.

At the same time, I've also said we don't need to do anything. Pascagoula is a top quartile refinery. We have a tight value chain built around it. And I've also said we're value oriented. Any acquisition has to be at the right price. Any investment that we do has to earn attractive returns. That's all I can really say at this time.

Jason Gammel:
Okay, appreciate the comments.

Operator:
Neil Mehta, Goldman Sachs.

Neil Mehta (Goldman Sachs):
Congrats, guys, on a good quarter. Pat and Pierre, I want to get your thoughts on divestitures. You laid out a $5 billion to $10 billion target. You are about $2 billion of the way there. Just how do you feel about the ability to achieve that? Where do you think you guys are going to fall in the range? And just any updates on processes that might be outstanding.

Pat Yarrington:
Overall, Neil, we feel positive about coming in within the range that we've indicated, the $5 billion to $10 billion over the three-year period of time. We're at $2 billion so far. There is a little bit more that will come in, we believe, in the fourth quarter. We have certain marketing activities underway that should, we believe, realize results in 2019. So we feel comfortable about the $5 billion to $10 billion range.

For the assets being marketed, for example, in the UK, we're having significant interest being shown by multiple potential buyers. We feel very good about that range that we've given.

Neil Mehta:
That's great. And then when we talk to investors about -- who are a little bit more skeptical of the bullish view on Chevron -- they point to two things. I want you guys to address it head-on. And one is the concern that post-2020 capital spending might need to materially increase because you're in a period of harvest right now, but you might not have the projects to reload growth, post-2020.

The second source of concern is around production-sharing contracts in Asia and the risk of them rolling off, particularly in Thailand; less so of a concern around Indonesia. So anything you can say on both of those topics to help comfort the market would be helpful.

Pat Yarrington:
Okay. Well, let me just speak here to the issue around growth, into the early part of the next decade, and investment opportunities therein. We obviously have a wonderful position in the Permian and with other unconventionals. As you know, these are low capital intensity, short cycle, high-return opportunities for continued volumetric growth. So that's number one.

We've got TCO coming online with production in 2022. We have opportunities for de-bottlenecking our LNG plants in Australia. We're just getting [the plants] to a high-reliability, full run-rate position now; and we think the opportunity for reasonable de-bottlenecking is evident over the next several years.

We have growth potential in the deepwater. We have three potential areas in the US Gulf of Mexico: Ballymore, Whale, and Anchor. And I think that's where people are thinking there will be substantial capital [spend]. And our objective is to pace those out over several years. There's nothing in terms of the intensity on our future investments that would ever come close to the intensity that we had in prior years. People may think the history [of our capital spend patterns] is going to color our future, and that's really not the case.

We have growth potential, but it's going to be at a much lower capital rate. There may be some need to increase capital in, say, 2021 or 2022, but the increase will be small relative to where people might be thinking. What was the other question that you had? Oh, the concession extension.

Pat Yarrington:
I'm really glad you asked the question. There's been a lot written on this and it's a good opportunity to try to work through the specifics. We put concession extension information, or expiration information, in our stat supplement. So I really encourage people to look at those documents and get a good understanding of what is coming due when.

But if you look out over the next 3 to 4 years, we've got about six contracts that will expire. We have one that is in a non-producing area. This is at the Nsoko contract in Congo, which expires in 2018. In Indonesia, we have the East Kalimantan PSC that expired just about 10 days ago. The Makassar Strait PSC is going to expire in 2020. And we have a small NOJV PSC in China which is going to expire in 2022.

Those I just mentioned are relatively immaterial and not substantive. There are a couple that have more substantive impacts for us, and one would be the Rokan PSC in Indonesia; and this has gotten a lot of press lately. We bid on this [contract extension], but we were not the successful bidder. The government of Indonesia elected to return this asset to Pertamina, and [our concession] will expire in 2021. We're disappointed in that. But we put in a bid that we felt offered value to the government of Indonesia as well as to the Chevron shareholder.

Our net production in Indonesia today is about 100,000 barrels a day. But the earnings and cash contribution from that [asset] is much smaller than [the production] would indicate as a percentage of the upstream portfolio.

And then the other contract of note is the Erawan PSC in Thailand, which expires in 2022. I can't say a great deal about this [contract] at this particular moment, but we have put in a bid that is under evaluation. We are taking the same approach that we did in Indonesia, which is to put in a bid that we feel offers value for ~~Indonesia~~ [correction: Thailand] but also offers value for the Chevron shareholder.

Neil Mehta:
Thanks, guys. I appreciate the time.

Operator:
Phil Gresh, JPMorgan.

Phil Gresh (JPMorgan):

First question I guess would just be a follow-up on the Permian, given your success that you're seeing there, and that you hit your rig count targets for the end of the year. How are you thinking about the go-forward plan to your -- you talked previously about leveling off with the rig count, at this point. But given the success you're seeing, does this make you want to lean forward and add rigs in the Permian, or how are you thinking about that today?

Pat Yarrington:
We feel good about having gotten to 20 [rigs]. And our approach right now would be to take a bit of a pause and really focus on capturing all the efficiencies that we can for that 20-rig fleet. That's from the land position to the drilling to the completions, all the way through to the market realizations.

Our approach right now is to take a pause and work to gain all that efficiency. We're focused on the returns that we're getting from the investments that we're making. We want to make sure that we're as efficient with our capital and operations as we can be. We can always reappraise and look at our options and decide what we would like to do going forward.

I will say that it's not so much about the actual number of rigs that you have drilling, but it's the level of activity, the cost per BOE, and the results you're generating. I think, over time, we're going to try to move what we consider to be a critical performance metric away from the rig count to something that would be more indicative of an efficiency measure.

Phil Gresh:
Yes, got it. That makes sense. Second question is just on the balance sheet metrics: 19% gross debt to cap, but 15% net debt to cap, so you're trending quite well on the balance sheet. How do you think about the desire to -- given where we're at in the cycle, to continue to lower that metric versus other opportunities? You obviously started with the buyback last quarter of $3 billion. Is there any desire to potentially, at some stage in the future, increase that amount or given -- do you have a more kind of conservative macro view, and you'd rather stick with where you're at?

Pat Yarrington:
It's a wonderful question, and it's a great position to be in, Phil. We're only three months into the share repurchase program. We obviously feel very good about the cash generation that is occurring in the Company. And we've got a confirmed $18 billion to $20 billion capital program.

If we are in a position where we continue to see high cash generation, the market continues to be at prices near current levels, and we know our confirmed spending, then there's going to be surplus cash that is being generated. If those circumstances all materialize, then we would obviously give consideration to the size of the share repurchase program.

We'll look to see similar parameters to what I outlined back in the last quarter to be evident. In other words, we want to make sure that whatever we do, we can have [the repurchase program] be sustainable and that it's a reliable component available to our shareholders.

The improvement to the balance sheet supports sustainability of shareholder returns. Because to the extent that we have a stronger balance sheet, when we get into a downturn on price -- and we believe that a downturn, at some point, will come -- we've got a balance sheet that can help support distributions to shareholders through the thin part of the cycle.

Phil Gresh:
Sure. Okay, thanks a lot.

Operator:
Doug Leggate, Bank of America Merrill Lynch.

Doug Leggate (Bank of America Merrill Lynch):
So Pat, I'm afraid I'm probably the guy responsible for all these PSC questions, so I apologize. But I do want to follow up on the question from earlier, if I may. Thailand is a legacy tax concession and it's been re-bid as a PSC. The government has been quite transparent about the minimum terms. So I just wonder if you could address one issue.

If you look at third-party analysis on this, meaning tax -- very old tax framework information -- this thing could be as much as $2 billion of your cash flow this year. Is that anywhere close to being right? And if so, under the new terms, how would you expect the delta on cash flow to look, even though you might retain the contract from a production standpoint?

Pat Yarrington:
Doug, you're putting me in an uncomfortable position. I really can't comment while commercial discussions are underway and bids have been put forth and are being evaluated. I think we're going to have to wait and see what the outcome is from the discussions and whatever gets awarded. We're planning on learning the outcome of this decision by the end of this year. We'll give you an indication of the result at that time.

I can confirm that the bidding package does contain tougher fiscal terms. I think you can build that into your expectations. But exactly what the degree [of those terms] will be, I'm not at liberty to say, at this point.

Doug Leggate:
I certainly did not mean to put you in an awkward spot, but thanks for trying to answer it. My follow-up is hopefully a bit more constructive, and it's on the Permian. So, you're saying -- in your prepared remarks, you said you're running about a year ahead of schedule. So with the change in design and obviously the improvement we expect next year -- at least in Permian spreads, differentials, and so on -- would you then expect to basically maintain the same plateau target? Or given that you're running so far ahead, would you expect to see further upside risks to your production outlook? In other words, will you do more with less, or maintain the same -- or continue the same growth trajectory, and take what it gives you with the same level of activity, if you know what I mean?

Pat Yarrington:
We're really constructive on the Permian. Some things to keep in mind. We've been ramping up to 20 rigs. We're now going to have 20 rigs for the full calendar year 2019. So that will be a positive. We're seeing continued benefits coming from our new basis of design, and continuing improvements in efficiencies.

We also think that there's upside potential as we continue to fine-tune our well placement and really fine-tune the entire, value chain associated with the Permian. So, we're constructive on the Permian. And we'll certainly give you an update in our March 2019 SAM, which we've done for several years now running.

Doug Leggate:
Thanks for taking my questions, Pat. Appreciate it.

Operator:
Paul Sankey, Mizuho.

Paul Sankey (Mizuho):
Pierre, since you're on the line, I thought we'd go back to your IMO comments. There's been some recent press that the potential is for the market impact to be too severe for perhaps the administration to handle. I would imagine that would have to be on the gasoline price.

Could you talk a little bit more -- US gasoline price, for that matter -- could you talk a little bit more about how you think the effect of IMO will play out? And to be specific, do you think there will be a major impact on US gasoline prices as opposed to distillate?

And one other thing I would ask is that, as regards fuel oil, where do you expect the unused residual to end up? And how will that clear the market, given the transport difficulties there? Thanks.

Pierre Breber:
Okay. Thanks, Paul. There are a lot of unknowns and uncertainties around how IMO is going to roll through the system. I think part of the challenge is that IMO will not occur in a vacuum. You can't hold everything else constant. In 2020 there will be other supply and demand factors happening. What will the economy be doing at that point in time? What will sour crudes global production look like?

So, there are a lot of moving parts that are going on. But what you can step back and say -- and one of my comments alluded to -- if you look at the forward markets right now, you would see mid-distillates -- jet/diesel crack spreads -- increasing, post-2020. And you would see HSFO, or high sulfur fuel oil and sour crudes discounts widening. That makes sense, right?

As you point out, there is a lot of fuel oil that goes to the bunker market. The expectation is that there's not enough scrubbers that have been put in place to consume all the high-sulfur fuel oil. [Shippers] are going to look to alternatives, and one of those alternatives will be marine gas oil, which will look like distillate. Another alternative could be a low-sulfur fuel oil. So there's a lot that's going on in that space.

In terms of mogas, it's a difficult thing to predict because there's so many factors. We've seen crude move plus or minus $10 in a few weeks in the last couple months. Those [crude price] movements have a much bigger impact on gasoline pricing or any product pricing than potential IMO impacts. We're really talking just about [product] differentials.

And you can see mogas going either way. It could get pulled up if some of the intermediates that are used from mogas go to make distillates. You could also make arguments that it could weaken a little bit if runs are higher and there's excess mogas. So it's really something that I can't predict.

What we're focused on is being prepared for [IMO 2020]. We’re minimizing high-sulfur fuel oil production in our refineries by making small-scale modifications. We are seeing scrubber uptake increase for ship owners. We are looking to sell the HSFO we produce to them. We're looking at alternative markets that are non-marine, like power generation, asphalt, and those refineries with excess upgrading capability. We're confident that we are prepared for IMO.

We're also working on testing low-sulfur fuel oils -- different marine fuels, lubricants and additives -- and we're a leader in marine lubricants and additives. These will be a big part of the solution, so we're testing and developing new products. There's a lot of work underway. We got a little more than a year to go, and we'll be ready for it.

Paul Sankey:
Pierre, I feel like I'm not the first to have asked that question. Can you just give us any sense for the power generation market, and your expectation of scrubbing penetration? Thanks.

Pierre Breber:
On scrubbing penetration, in our view, if you step back, the most economic way to comply with the IMO regulations is for ship owners to put in scrubbers. That's a much more cost-effective mechanism than for refineries to invest capital. We're not looking to make any large-scale investments [in our refineries] that are IMO-related. It's because we view [IMO 2020] as transient.

One thing about our markets is, they work. And when arbs open up, they get closed. There's lots of players. There's lots of capital. And there are lots of people who are working to reduce arbs.

On power generation, there's a pretty good-sized market in the Middle East and other places. It's a lower-value market, clearly. But our view is that some power generation demand is required by the market to go through the [IMO 2020] transition. Over time, we expect scrubber uptake to increase, and that will be the primary mechanism of complying with IMO.

Paul Sankey:
Pierre, thanks. I'll let someone else have a go. Thank you.

Operator:
Paul Cheng, Barclays.

Paul Cheng (Barclays):
Pierre, since you are here, so two questions for you; one really short. Your refining system, can you tell us what percentage you run as heavy oil, those we define as over -- below 25 API? And how much is the medium sour? You run those we define between 25 to 30, 31 API?

And the second question is that given your position that when you're looking to support your upstream, will you be involved, or that think you need to be involved in terms of helping to ensure we have sufficient Gulf Coast oil export capacity? Because it may have some concern by late 2019 or early 2020, where you may have a gap. Or that you think that it's so transitionary that it's not really a concern; and you guys don't need to be as an equity owner in those?

And also then if you can comment on [Duvernay] -- that it seems like we also have infrastructure issue. And that will -- given your position, and you're doing some pilot project and all that, is that something that you guys will involve? Or need to be involved, I guess the question is.

Pierre Breber:
Let me take the first one. We do not disclose specific sour content or API gravity. What we do disclose in our annual report supplement is the region or country of origin of the crudes. And I think folks can figure it out from there. Again, I showed a chart that showed that we have the highest Nelson complexity -- the highest amount of upgrading capacity. Our refinery network is designed to run lower-value feedstocks, and we've invested to make that happen, but we don't disclose specifics on that.

On your second question, on how we think about the upstream in the Permian. All I would say is that the downstream has to stand on its own. Any investment we do has to stand on its own. We're competing as a segment. I showed charts illustrating how we compare in earnings per barrel against our major competitors. We are part of an enterprise, and if we can have the synergies with the upstream, of course that's an added benefit. But for investments in the downstream, we can't ride on the back of, in particular, the very attractive economics in the Permian. Again, we have to have investments that stand on their own merit, that compete against our competitors. Any extra benefit from synergies is upside on that.

On the third question, I think it was around takeaway, and I'll leave that with Pat.

Pat Yarrington:
I think you had a question about export capacity. Our corporate view would be, yes, there may be a need to build out export capacity over the next two or three years. But going back to the belief that markets see this opportunity, and that capacity will in fact be built out, we don't see it as a risk to flow assurance.

We have, ourselves, dedicated export capacity of about 25,000 barrels a day now. We see that expanding in the early part of ~~next year~~ [correction: 2020] to about 80,000 barrels a day. So far, we have exported about 8 million barrels [through July]. So we feel that we're investing appropriately for our flow. But we don't think, in general, over time, that there will be a risk to flow assurance in the Permian because of export capacity.

Paul Cheng:
Pat, does that same apply to in the [Duvernay] area in Canada, that you don't believe that you need to involve on the buildout of the infrastructure there?

Wayne Borduin (General Manager, Investor Relations, Chevron Corporation):
Your question is in reference to the oil sands, Paul?

Paul Cheng:
No, to the Duvernay.

Wayne Borduin:
Yes, I think I would just chime in, Pat. I think we have previously disclosed that we committed to the Pembina infrastructure agreement that is well-paired to enable our production out of the Duvernay. And you'd expect that as we continue to progress development there, that we would be able to step into additional capacity agreements to enable that flow.

Paul Cheng:
Okay. Thank you.

Operator:
Blake Fernandez, Simmons & Company.

Blake Fernandez (Simmons):
Pat, a question for you on CapEx. It looks like you are trending about 5% above. Could you talk a little bit about what the drivers are there, whether it's activity or inflationary based? And should we be thinking about that kind of upward momentum into the next couple of years as well? So maybe like toward the upper end of your range?

Pat Yarrington:
Good question, Blake. Yes, we're about $600 million above our plan on a year-to-date basis, if plan was ratable. About $150 million of this or so relates to inorganic lease acquisitions, lease bonus payments. I said on my prepared remarks, we expect that inorganic number to go to about $600 million for the full year.

But back to the nine months, we're about $450 million over on an organic basis, and there's really several reasons for this. It's not concentrated in any one particular area. The first thing I would call out is the fact that oil prices have been noticeably higher in 2018 than the planning premise that we used when we put the budget together.

There were capital cost savings that we had built into our plan that we thought we would be able to capture. And we really haven't been able to capture those. Cost trends stopped going down and, in fact, have leveled out. Some have even turned the other direction, along with oil price. So there's a piece of the overrun that relates to that.

There is a piece that relates to major capital projects. Jay mentioned TCO on the last call, but there's other projects with small overruns.

And then there's also more that is being spent in the Permian. We’ve talked about the drilling efficiencies, the new basis of design, and the fact that we're able to prosecute the development plan against more acreage than we had originally envisioned. High-density fracs cost more, but, in fact, the economic outcomes are really outstanding. The dollar per barrel is much better. So that's good money being spent. Those are the reasons that I would outline for the overrun that we have so far.

In terms of inflationary pressures, I will say we are continuing to see inflationary pressures, for example in the Permian. And we do expect that increases there may be in the order of 5% to 10% for 2019. In general, oil prices have been higher, and the cost structure in the industry has moved up some. I would say yes, we are facing some inflation, and that would be something that is reasonable to build into your expectation.

Blake Fernandez:
That is helpful. Thank you very much. The second question, I hope you didn't necessarily cover this in exact detail on Paul's question, but mine was on the Permian takeaway. I think in last-quarter's call you had highlighted excess capacity through June, and then ample takeaway for non-operated production through 2019.

I'm just curious, with the massive ramp-up that we're seeing here, are you still pretty well taken care of from a takeaway capacity through that same time frame in, say, throughout next year?

Pat Yarrington:
Yes, we are. The whole process that we have -- whether it be for crude or NGL transportation and fractionation or gas -- is trying to stay ahead of what we expect the Permian growth to be. We do this through securing, in increments, contractual offtake. We feel very nicely covered for our position out of Midland on those elements for the next couple of years. The team that we have working this will also consider production growth for future periods.

Blake Fernandez:
That’s great. Thank you.

Operator:
Alastair Syme, Citi.

Alastair Syme (Citi):
Pat, can I just ask what makes Tigris different from Ballymore, Whale, and Anchor?

Pat Yarrington:

I think it fundamentally comes down to the economics that we anticipate out of those individual developments. [The economics are] influenced by the size of the resource, the development strategy -- independent topsides or tieback opportunities, and the complexity of the reservoir. There's a number of factors.

Tigris had its own complexity because it was a three field aggregated development. So you shouldn't read [anything] into the fact that we decided to exit the Tigris leases. We are still dedicated to the deepwater. We have expertise in the deepwater. We picked up a significant number of leases in the Gulf of Mexico deepwater, as well as offshore Mexico and Brazil as well.

So, we're still invested in the deepwater, and we're looking for the highest-return projects. It's all about making choices and going after what we believe will be the best opportunities to secure high returns in our portfolio.

Alastair Syme:
Thank you. Can I -- as a follow-up, can I just return to the discussion around PSCs? And just clarify for the sake of the guidance that you put in the SAM around cash returns out to 2020. What sort of assumptions are made around contract renewal?

Pat Yarrington:
On the two important ones that I talked about for both Rokan and Erawan, the assumption in the materials that we provided back in March were that these concessions would be extended. In terms of the concession extension dates, though, I think that's important. Both of those [expire in] 2021 (Rokan)/2022 (Erawan). So for the next several years, we still have those available to us.

Alastair Syme:
Thanks for the clarification.

Pat Yarrington:
I would just say because we've seen such strong growth in the unconventionals, even without those concession extensions, we can still see growth in our base plus shale and tight.

Alastair Syme:
Great. Thank you very much.

Operator:
Roger Read, Wells Fargo.

Roger Read (Wells Fargo):
Could we follow up a little bit your comments on the cost inflation on the CapEx side? Specifically, any update on TCO, relative to where we were? And then how these cost inflation issues or CapEx overruns affect the overall spending budget or run the risk of? And then as you're starting to think about where projects are going to bid out for 2019, is that already being incorporated in expectations?

Pat Yarrington:
Yes. Roger, thanks for the question. First, let me just reiterate. Staying within the $18 billion to $20 billion range is our focus. If we see cost pressures on major capital projects or from general inflation, we can make portfolio choices to ensure that we stay in our capital range. We think it's very doable because we've got activity lined out over the next couple of years.

For TCO in particular, let me just make a few comments. I visited TCO about 10 days ago with both Wayne and Jay Johnson, and so I have a first-hand view of what's going on there. I wanted to make a couple of personal observations. We're only 2.5 years in, and we've still got 3.5 years to go. First oil is still scheduled for 2022, so we're only about 50% of the way through the project.

From my observations, a number of things are going quite well on the project. It's a big, complex project. It's been broken down into individual work streams. And those individual streams are lined out into productivity or work packages, where activity is being tracked on a daily, weekly, and monthly basis. We are seeing site productivity improve tremendously.

Jay mentioned on the second-quarter call that the rest of 2018 and 2019 are the really critical execution years. We're moving away from civil and underground work into the MEI phase. 2019 will be an absolutely critical year from an execution standpoint.

I was really impressed with the productivity gains that we're seeing. And, of course, we still have a lot of work ahead of us. I don't want to get too far out over my skis or overstate anything here, but things are working well. The logistics are working well. The modules are being delivered. It's being lined out, and proceeding quite nicely.

Roger Read:
No, that's fair. I think given the performance of the quarter, we won't try to put you on the rack or stretch you right here.

Pat Yarrington:
I appreciate that.

Roger Read:
The follow-up question: as we think about the outperformance in the Permian this quarter -- I mean, it's been building for a while; it just really spiked up here -- between the operated and the non-operated, and thinking about your comments on the high-density fracs and so forth, is -- should we think about the outperformance being overwhelmingly within Chevron operated rigs or spread out?

In other words, what you're learning in your own wells is being applied even to the non-op. I'm just -- as we think about a change in rig percentages, operated versus non-operated, whether or not that would affect growth going forward.

Pat Yarrington:
In the quarter, the contribution in terms of absolute production between operated and non-operated was about the same. We've been building up activity on the operated and non-op side as well. But, of course, the non-ops had production activity that started several years previously. The contributions in the quarter are relatively comparable between non-op and co-op. Both areas are seeing improvement.

Roger Read:
All right, great. Thank you.

Operator:
Sam Margolin, Wolfe Research.

Sam Margolin (Wolfe):
I'm sorry it's late stage in the call. I sort of have a thematic question, but I'll try to keep it concise. You made a reference to fiscal terms kind of tightening or escalating in Thailand. That might be happening in other places, too. And at the same time, even with cost inflation in the Permian accounted for, effectively the opposite is happening, where you're getting more efficient and economics are improving.

So I guess my question is just broadly, how do you manage that? In the past, you've set a level of where you think unconventional production could be within your portfolio. But if the economics, on a relative basis, are getting so much better than they are everywhere else, what's the process of managing your mix here to make sure that you are optimized when things on the screen seem to incent you to go wildly in one direction?

Pat Yarrington:
Sam, I would say we have a fundamental belief in the value of diversification and having a diversified portfolio. And we have several legacy assets, whether you think of Australia or unconventional in the Permian, TCO, deepwater. We have several significant asset classes that we want to continue to pursue.

And you're right; in some locations around the world, you'll see a tightening of fiscal terms. But in other locations around the world, you see the fact that the host governments are realizing that in order to incent foreign investment, they need to revise the fiscal terms in a way more favorable to an investor like Chevron.

So, it ebbs and flows, and we're in the business for the long-term. We continue to assess our portfolio and try to make the best decisions we can make; not only for the short term, but also for long-term -- production growth, reserve replacement, cash flow growth, dividend growth, et cetera. We look at it from a portfolio perspective.

Sam Margolin:
All right. Thanks so much for all the color on a long call.

Pat Yarrington:
Thank you. I guess that was our last call, so I want to thank everybody for your time today. We certainly appreciate your interest in Chevron, and we appreciate everyone's participation on the call.

Have a good day. Jonathan, back to you.

Operator:
Thank you. Ladies and gentlemen, this concludes Chevron's third-quarter 2018 earnings conference call. You may now disconnect.