3Q23 Earnings Conference Call
Edited Transcript

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Chevron

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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 Investor Conference Call, please listen to the webcast presentation posted on chevron.com under the headings "Investors," "Events & Presentations."

Operator: Good morning. My name is Katie, and I will be your conference facilitator today.

Welcome to Chevron's Third Quarter 2023 Earnings Conference Call. At this time, all participants are in a listen-only mode. After the speaker's remarks, there will be a question and answer session and instructions will be given at that time. If anyone should require assistance during the conference call, please press star then zero on your touchtone telephone. As a reminder, this conference call is being recorded. I will now turn the conference call over to General Manager of Investor Relations of Chevron Corporation, Mr. Jake Spiering. Please go ahead.

Jake Spiering: Thank you, Katie.

Welcome to Chevron's third quarter 2023 earnings conference call and webcast. I'm Jake Spiering, General Manager of Investor Relations. Our Chairman and CEO, Mike Wirth, and CFO, Pierre Breber, are on the call with me today.

We will refer to the slides and prepared remarks that are available on Chevron's website.

Before we begin, please be reminded that this presentation contains estimates, projections, and other forward-looking statements. Please review the cautionary statement on Slide 2 [that can be found with today's presentation materials on Chevron's website].

Now, I will turn it over to Mike.

Mike Wirth: I want to start by acknowledging the tragic events in the Middle East. We're deeply saddened by the loss of life, and our hearts go out to those affected by the war. We continue to prioritize the safety and well-being of our employees and their families and the safe delivery of natural gas.

Earlier this week, we announced that Chevron entered into a definitive agreement to acquire Hess Corporation. We expect this transaction to close in the first half of 2024. We look forward to providing updates in the future.

Now turning to the third quarter, we continued to make progress on our objective to safely deliver higher returns and lower carbon by:

- Returning more than $5 billion to shareholders for the sixth consecutive quarter and delivering ROCE greater than 12% for the ninth straight quarter; and
- Investing in traditional energy by closing the PDC Energy acquisition and in new energies by acquiring a majority stake in a green hydrogen production and storage hub in Utah.

And earlier this month, we released our Climate Change Resilience Report which details our approach, actions and progress in reducing carbon intensity and growing new, lower carbon businesses. I encourage everyone to read the report, available on Chevron.com.

At TCO, base business continues to deliver good results. The planned turnaround was completed ahead of schedule, the reservoir is performing well and the plant remains full. We expect a higher dividend in the fourth quarter.

TCO has achieved mechanical completion at the Future Growth Project (FGP). Following slower than expected commissioning progress, we conducted an independent cost and schedule review. We now forecast the Wellhead Pressure Management Project (WPMP), which is the field conversion from high pressure to low pressure, to begin start-up in the first half of 2024 and to continue through two major train turnarounds. FGP is expected to start-up in the first half of 2025 and ramp to full production within three months. Total project cost is expected to increase between 3% to 5%.

TCO production on a 100% basis in 2024 is forecasted to be about 50 thousand barrels of oil equivalent per day lower than 2023 due to a heavier turnaround schedule and planned downtime for WPMP conversions. TCO is expected to reach greater than 1 million barrels of oil equivalent per day in 2025 when FGP fully ramps up. Free cash flow from TCO in 2025 is expected to be more than $4 billion – Chevron's share at $60 Brent – down around $1 billion from our prior estimate.

Our focus remains on safe and reliable commissioning and start-up.

I'll now turn it over to Pierre to discuss the financials.

Pierre Breber: We delivered another quarter with strong earnings, cash flow and ROCE.

This quarter's results included two special items: a one-time tax benefit of $560 million in Nigeria and pension settlement costs of $40 million. Foreign currency benefits were $285 million. The appendix of this presentation contains a reconciliation of non-GAAP measures.

Organic capex this quarter included about $200 million for PDC legacy operations after closing in August.

Our balance sheet remains strong, ending the quarter with a net debt ratio in the single digits.

Another quarter of solid cash flow enabled us to deliver on all of our financial priorities.

Despite restrictions during the PDC transaction, we were able to repurchase well over $3 billion in Chevron shares. Cash used to reduce debt was primarily related to PDC's higher cost borrowing. Cash balances ended the quarter near $6 billion, a little above what's needed to run our businesses.

Adjusted third quarter earnings were down $5.1 billion versus the same quarter last year.

Adjusted Upstream earnings were lower mainly due to realizations and negative timing effects. Higher unfavorable discrete tax charges and exploration expenses were partly offset by lower DD&A, Venezuela cash recoveries and other favorable items.

Adjusted Downstream earnings decreased primarily due to a negative swing in timing effects and lower marketing margins.

Compared with last quarter, adjusted earnings were down just over $50 million.

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Adjusted Upstream earnings were roughly flat as higher prices and volumes were offset by unfavorable discrete tax charges and negative timing effects due to the rise in prices. DD&A and opex were both higher in part due to the addition of PDC legacy assets for two months in the quarter.

Adjusted Downstream earnings increased primarily due to higher refining margins, partially offset by unfavorable timing effects.

All Other was down on unfavorable tax items and decreased interest income in line with lower cash balances.

Third quarter oil equivalent production was up 6% over last quarter primarily due to two months of legacy PDC production. This was partly offset by a planned turnaround at TCO and pitstop at Gorgon. The Permian, excluding legacy PDC, was down 2% due to lower non-operated production; company-operated production was flat with the second quarter.

Now, looking ahead.

Our fourth quarter estimate for turnarounds and downtime includes approximately 30 barrels of oil equivalent per day for Tamar.

We anticipate affiliate dividends in the fourth quarter to be largely from TCO. As a reminder, we record a 15% withholding tax on TCO dividends.

Due to the pending transaction with Hess, share repurchases will be restricted pursuant to SEC regulations. Chevron expects share repurchases in the fourth quarter to be around $3 billion plus or minus 20%, depending primarily on the timing of the Hess definitive proxy statement mailing.

In summary, our actions and performance show that Chevron keeps delivering strong results. With a strategy that remains clear and consistent, we're well positioned to deliver value to our shareholders in any environment.

With that, I'll turn it back to Jake.

Jake Spiering: That concludes our prepared remarks. We are now ready to take your questions. To allow for questions from more participants, we ask that you limit yourself to one question. We will do our best to get all your questions answered.

Katie, please open the lines.

Operator: Thank you. If you have a question at this time, please press star one on your touchtone telephone. To allow for questions from more participants, we ask that you limit yourself to one question. If your question has been answered or you wish to remove yourself from the queue, please press star two. If you are listening on a speakerphone, we ask you please lift your handset before asking your question to provide optimum sound quality. Again, if you have a question, please press star one on your touchtone telephone.

We'll take our first question from Roger Read with Wells Fargo.

Roger Read: (Wells Fargo) Yes, thank you, good morning.

I was hoping we could dig into the international upstream. Just a little short on what we were expecting this quarter. What some of the factors were, other than the ones called out – the FX issue and the tax benefit in Nigeria?

Mike Wirth: Yes, Roger. I'll let Pierre cover this in a little more detail, but I recognize this quarter was a tough one to model. There's pretty material or significant non-cash charges. Timing effects, primarily inventory costs, [which] we see with rising prices, some tax reserves, charges for legal abandonment and other things, and then some lower realizations which are mixed and the lag effect in some of our LNG pricing.

On timing and inventory costs in particular, on period-to-period comparisons where we had a prior period, whether it was last quarter or the same quarter last year where prices were coming down and then in the current period, we see prices strengthening significantly, you really get pretty significant deltas on the way we cost inventory. And if you go back to the first quarter of 2022, we had some similar dynamics.

So anyway, that's kind of high level on it. Pierre, maybe you can talk a little bit more about the upstream – international upstream in particular.

Pierre Breber: Yes, it's a subset of what you talked to, Mike.

Roger, the largest timing effects this quarter were cargoes on the water. You'll see that primarily in the international upstream, international downstream. Timing effects are in three buckets: you have paper mark-to-market, you have on-the-water inventory and then you have on-land inventory. It's really cargoes on the water that drive most of the effect, cargoes that are in transit and cross over quarterly periods. That's what the trajectory of prices, as Mike indicated, is really what drives that.

Mike talked about abandonment estimates. Those will show up in depreciation, and we saw that in the international upstream.

And then in LNG, you see some lag pricing. We also saw some mix between contract cargoes and spot cargoes on LNG. On the liquid side, we saw some mix effects. It's a bit of where the liftings are relative to production in terms of tax jurisdictions, the types of products and how they trade in terms of discounts to Brent.

There were a number of items in international upstream. And you could follow up, Roger, with Jake to cover any more details.

Operator: We'll take our next question from Josh Silverstein with UBS.

Josh Silverstein: (UBS) Good morning.

On TCO, you mentioned that in 2025, you expect the cash flow to be about $1 billion lower, around $4 billion versus $5 billion previously. Is that just due to the project delays? Or is there higher cost estimates now in that, so you lower [affiliate] distributions from there? Or is there something else that's driving that?

Mike Wirth: Yes, Josh, there's going to be some more capital, we said 3% to 5%. Think around $1 billion Chevron share over 2024 and 2025, probably a little more weighted to 2024 than 2025.

Cash flow from the operations will be lower by about $1.5 billion at $60 Brent in total over the next 2 years really due to the delay in the project. It's equivalent to about 50,000 barrels a day in net production in each of those years.

In total, we expect our share of dividends to be lower by about $2.5 billion across 2024 and 2025 from the prior guidance.

It's a combination of those things. We had previously guided to above $5 billion, we're now seeing above $4 billion [for Chevron's share of TCO's free cash flow at $60 Brent]. A little more of that coming from production and cash flow from ops as opposed to capex.

Pierre Breber: And the delay in WPMP doesn't have any impact really because there was no incremental production. The effects that Mike was talking about in production are really from the delay in the start-up of the FGP, which obviously adds incremental production.

Operator: We'll go next to Neil Mehta with Goldman Sachs.

Neil Mehta: (Goldman Sachs) Yes, thank you. I just want to stay on the TCO question.

As you think about, Mike, the biggest gating factors to getting from here to completion around FGP, just walk us through the landscape and the key milestones that you will be watching and we should be watching to give us conviction that the project is coming into service.

Mike Wirth: The main message here, Neil, is as we completed both WPMP and then mechanical completion of FGP, and we've begun to get deep into the commissioning, we've previously mentioned we worked through some technical issues with our utility systems. As we did that and we saw some of these impacts, we commissioned an independent cost and schedule review off cycle. We normally do these annually, but we didn't want to wait.

As we saw some of this evidence that things were going slower, there were some more discovery work, we sent in an independent team to give us a cold eyes assessment on cost and schedule. I think the main thing that I would distill that down to is the recommendations from that, that are embedded in our updated guidance today, reflect a more conservative forecast of commissioning progress.

We're assuming things will take longer than the prior plan. We're assuming we're going to have discovery items that tend to come up in complex projects like this. And in response, we've implemented some significant changes in terms of how we're approaching this.

We've moved contract resources over from 3GI, which is a portion of the Future Growth Project, which is now completed and fully commissioned, over onto the other commissioning work. So, we've added contract resources there.

We've brought in experienced turnaround and operations people that are very skilled in the discovery work, in managing through the restart of and operations of facilities, to help us with this. And then we've also added technical resources to address any unplanned discovery items that would come up.

We've had a significant change in our approach to this. We've got a more conservative guidance here that we're issuing now, and we'll continue to talk about this every quarter.

The main things to look at here are we've got big compressor trains that will start up for pressure boost, which is a key driver of this high-pressure to low-pressure conversion. These are very large machines so those are key milestones. After that, we've got metering stations that are converted from high pressure to low pressure. Over the next few quarters, and there's, I think, 40-some-odd metering stations as you go out through the entire field. We've got these two big turnarounds that I've talked about. All of those are key milestones that we'll be tracking very closely, and we'll update you on those as we go forward.

Operator: We'll go next to Devin McDermott with Morgan Stanley.

Devin McDermott: (Morgan Stanley)

Good morning, thanks for taking my questions.

I wanted to just stick with upstream but actually ask about Venezuela. You've had some increase in production year-over-year, given the initial sanction relief, and there's obviously been some additional sanction relief announced just since the last quarterly call. I think you might have been on an interview this morning. You made some comments that you could see a sequential increase in production between now and year-end.

I was wondering if you could just step back, talk through what impact the sanction relief has on your production profile and also willingness to invest in that region. And can you remind us how impactful Venezuela volumes are for your corporate cash flow?

Mike Wirth:

Sure. We have seen some action now from the U.S. government. We had been previously operating under an OFAC license, which was modified at the beginning of this year, a general license. There's some specific licenses that go with that, that define the terms under which we can operate.

The recent action in new general license issued by OFAC really kind of opens up operating room for others more so than it does for us. It doesn't materially change our circumstances here. I think what you'll see is some more people lifting crude, you'll see more crude flow to the U.S. I don't think the impact on our operations really is particularly significant.

We are up to something around 130,000 barrels a day from maybe 60,000 barrels a day earlier this year. We still think we can get to 150,000 or so by year-end. We are seeing improvements and expect there's some more that we can see through the balance of the year.

The cash from that is going to pay legitimate operating expenses, tax and royalties, recover some past dues that we are owed. We're really working on what I would call pretty straightforward field maintenance and things to restore production that aren't particularly long-cycle or capital-intensive and staying within the kind of cash that's being generated from those sales in order to fund that.

I would expect that's the posture we'll remain in for a while here until we see how the longer-term sanctions environment plays out, the political situation in the country with elections and the like, and continue to make progress on recovery of the past dues that I mentioned. So not a lot of change, I guess, I would say, from our point of view. Pierre, maybe you want to comment on the cash and production.

Pierre Breber:

Yes. Consistent with what Mike just said, we're continuing to do cost affiliate accounting, which means we don't record production or reserves – so that's not reflected in our numbers – we only record earnings when we receive cash.

We're recording a proportionate share of equity earnings, but only what we actually receive in cash. That's something that we'll continue to look at. And as Mike said, depending on all those potential triggers down the road, elections and such, we could go back to equity accounting at some point in time, but we have not made that decision yet.

In terms of cash flow, it's about 1% of our cash flow. It's modest, of course, but it's more than it was before. And as Mike said, operations there are continuing well. We're getting a little bit of cash, and we'll just see where it goes from here.

Operator:

We'll go next to Biraj Borkhataria with RBC.

Biraj Borkhataria: (RBC Capital Markets)

Hi, thanks for taking my question.

I'm sure you'll get a few more on TCO. I just want to ask about the Permian. Last quarter, you gave some very helpful data points on well productivity this year. I was wondering, particularly for the New Mexico side, if you had any incremental comments for wells drilled in the third quarter because I know it was a pretty small sample size of POPs in the first half of the year. So, any comments there would be helpful.

Mike Wirth: Yes, and I might give you some kind of broader commentary on Permian performance as well.

Overall, production was down just a little bit, about 2% in the quarter. That was entirely driven by non-operated joint ventures, and primarily a couple of the operators had delays in putting wells online due to frac hits and some other factors. There was also some takeaway capacity, on the Permian highway, constraints that resulted in some unplanned downtime.

COOP production in the third quarter was essentially flat from the prior quarter, which is what we had guided to, and that's despite having some wells that were choked back due to some surface constraints. In one development area, we're seeing higher-than-expected CO_2 content in the gas and others in the area are as well. We've got third-party handling and process facilities that are constrained by that and can't handle all the CO_2. So, we're choking wells back. There's a new federal regulation that I won't get into the details, but it affects how we meter production and it prevents co-mingling. And so, we've got wells choked back until we can get some new meters in place. And then we've got some produced water limits that have come into effect in some areas. There's a number of things that are not indicative of well performance but other surface realities that we're working our way through that are impacting COOP production a little bit.

In New Mexico, you're right. We got more POPs in the second half of the year. We've popped about 60% of the planned wells in New Mexico. The balance, almost half, come on in the fourth quarter. POP performance has generally been strong. Some of those wells are hit by the facility constraints that I've talked about, but overall, well performance is aligned with our type curve expectations.

I think when we get to the fourth quarter call, Biraj, we'll come back with some more detail on type curves. We'll have enough of them online. We'll have enough months that we can start to give you some of the same kind of evidence that we did last quarter to show you the performance.

Operator: We'll go next to Sam Margolin with Wolfe Research.

Sam Margolin: (Wolfe Research) Thanks, good morning.

Maybe we'll stick with the U.S. and ask about just the U.S. upstream capex number. There's a lot of moving parts in here. You've got incorporation of PDC. You have kind of GOM projects and Ballymore coming into play, inflation and then timing effects that you alluded to.

I guess when you think about this quarter's U.S. upstream capital, how would you characterize it just overall? Would you say it's sort of on plan or overly influenced by any one of these factors that may or may not be mitigated over time?

Mike Wirth: Sam, you're right. We are seeing pressure in the U.S., and I think we're probably going to end up higher than our budget as we end the year. PDC is being integrated into the factory pretty much as we expected. It's an increment because it wasn't in our original plan, but it's really not a driver of this.

The big thing is we're seeing more feet drilled per rig and more completion feet than we had planned [in the Permian]. The productivity of the primary development activity has continued to improve, but that means we spend more money on tubulars, on sand, on water, than we had anticipated. It's kind of the good news, but it brings with it some costs.

[Also in the Permian,] we've got some long lead items where we're seeing supply chain realities that say we need to place long lead orders earlier. Some things we otherwise would have ordered next year that we've actually moved ordering and initial payments on into this year. There's some long lead dynamics going on.

And then I mentioned earlier, produced water is becoming an issue [in the Permian]. The reinjection of that and doing that in a way that minimizes the incidences of induced seismicity. We've got some more produced water handling infrastructure spend.

I would say those are kind of the primary drivers, and that's pushing the Permian to be a little hot.

Gulf of Mexico is pretty well right on plan. What you're seeing there is really a function of PDC, which is just an increment that's been added, and then some additional costs in the Permian program that we really hadn't anticipated as we went into the year.

Pierre Breber: I'll just add, if you take out inorganic – which is $600 million year-to-date, $400 million in the third quarter primarily for ACES – and the $200 million that we had for PDC in the third quarter, we're about $200 million above the ratable budget. Of course, fourth quarter tends to be higher. So as Mike says, we'll likely end the year a little bit above budget.

Operator: We'll go next to Paul Cheng with Scotiabank.

Paul Cheng: (Scotiabank) Thank you, good morning.

Can I go back to TCO? It's a little bit of the late stage for the cost increase and everything. I guess the question is that, I mean, what have we learned from this process and to ensure that your future project execution will become better and not facing the entire problem there?

I mean, it has been a challenging project all along, I think, to a number of different reasons. But quite frankly, this is a bit disappointing at this very last stage for the bit of the slip in the schedule and also the cost increase. Thank you.

Mike Wirth: Yes, Paul, thank you. I share the sentiment. I understand where you're coming from. Big complex project, you've been along for the whole ride, so you know early on there were some engineering issues that we confronted and addressed.

In the middle of it, the big thing was the pandemic and demobilizing, remobilizing, building medical facilities, and a whole bunch of stuff that we had to manage our way through and was complex and difficult, and our folks did a great job, but it clearly impacted cost and schedule.

The big thing here, Paul, is – and you have to remember, we're redoing the power infrastructure for the entire field, which is, geographically speaking, an enormous space, and this is infrastructure, frankly, goes back a lot of it to Soviet days – there's an entire new power distribution system. We're taking the entire field from high-pressure production to lower pressure in the WPMP process and then building the really large sour gas injection and incremental production facilities.

It's almost a field-wide refurbishment of a lot of it and then this big increment of production. The commissioning of that is incredibly complex. As we went in and did this cost and schedule review relatively early in the commissioning process, based on what we were seeing, what became evident is that we need to account for that complexity in our schedule. I don't think it was fully reflected in the schedule.

In a big, complex project like this, you find things. Early on, we found challenges in the utility system and it cost us some time and that ripples through.

The guidance we're giving you now is, really what I would say is, it's more conservative because it assumes that those kinds of things are going to be encountered for the balance of the project. We need to set expectations that those are the realities that we're going to be dealing with and that's why the schedule delay, it's all in commissioning.

Bulk construction is completed. All the equipment is there. This really is the final commissioning process. If we do well, we could end up on the front end of those windows that I gave you. But we've given you those because our experience says we should not plan for that. We've got to plan for the reality of these things.

As I mentioned in response to the earlier question by Neil, we've added incremental resources in multiple areas now to anticipate and be prepared for these kinds of challenges. I think the lesson is on projects like this, of which there are few, in the future our commissioning plans will reflect that complexity more completely than the commissioning plans did on this one.

Pierre Breber: I'll just add some comments on affiliate dividends. We've given a guide on fourth quarter affiliate dividends, which falls short of the full-year guide that we did at the start of the year. That shortfall is not from TCO. That's from CPChem, Chevron Phillips Chemical Company, on lower petchem margins. It's also from Angola LNG on lower TTF prices than we had assumed. We've also had some of the Angola LNG cash come back to us as return to capital.

In terms of TCO, we had a $600 million dividend, Chevron share, in the second quarter. We can't get ahead of the TCO Board on the fourth quarter, but 90% or so of the fourth quarter guide is related [to] TCO.

I'll remind you last year that TCO dividend was $1.6 billion, Chevron share. All these numbers are before the withholding tax. We'll see a pretty significant increase in the total year TCO dividend.

Now some of that was getting some of the excess cash off the balance sheet like we were talking about. But if you go back to the period prior to the start of this construction, so the period into 2015, this year's dividend will be similar to what we saw from that time period.

The inflection is happening after five years of either not receiving dividends or, in fact, putting cash out, essentially having negative free cash flow. We know production is going to be down next year. We showed that. So, you'd expect dividends to reflect that a little bit. We have a little bit of increase in capex. And then we'll be heading to this more than $4 billion in 2025, and all of that guidance is at $60 [Brent].

We're seeing some positive news in terms of the cash flow coming out. Clearly disappointing news on the revised schedule, but we're going to work hard to deliver it in the front end of the range.

Operator: We'll go next to John Royall with J.P. Morgan.

John Royall: (J.P. Morgan)

Hi good morning. Thanks for taking my question.

I have a follow-up on the Permian ex PDC. You were down 2% in 3Q including the non-op piece, and really helpful color there from Mike on Biraj's question, but it does leave a pretty big jump to hit [full year] guidance in 4Q, around 10% if I calculate it right. So, are you sticking with that 770 [MBOED] guide for the legacy piece? And if not, is there a good way to think about 4Q production in general?

Mike Wirth:

Yes, John, we're not changing the guidance. Overall, on production excluding PDC, we expect to be at the lower end of overall guidance. Permian production is expected to ramp up in the fourth quarter. Full year production expected around 770 – 780 [MBOED] or so if you include PDC. So yes, the guidance is still intact for the Permian. Go ahead, Pierre.

Pierre:

Yes. Mike talked about the 2% shortfall on non-op, which averages about 0.5% [a quarter]. He talked about also some of these surface constraints. So, we have worked to overcome the shortfall we saw in non-op in third quarter to deliver that.

So, no change in guidance. But clearly we have a little more work to do in the fourth quarter to achieve it. We do expect the fourth quarter [to have] more POPs and more production in line with the plan that we laid out earlier this year.

Operator:

We'll go next to Doug Leggate with Bank of America.

Doug Leggate: (Bank of America)

Thanks, good morning everyone.

Mike, I know you've been traveling around so thank you for making the time for us this morning. I want to try and defend you a little bit here this morning because if you look at the remaining life of Tengiz, about half of that value has been taken out of your stock this morning. I can't imagine you're happy about announcing other series of challenges. So, my question is this, at a philosophical level, how would you characterize what you and your management team and the organization are doing to avoid these kinds of issues on major projects going forward? You've got a lot of things in the queue through 2027. Why should the market be comfortable that you can execute on that timeline with what you have in your portfolio?

Mike Wirth:

Well, Doug, you're right. I think there has been a reaction in the market this morning to this. We've spent a lot of time, back to Jay Johnson, spending time not only in these calls, but traveling around talking about what we're doing on capital project execution.

This is a unique project, and I won't repeat the things that I went through earlier with Paul, but this is a large, multi-year effort that had supply chains coming in from all the way around the world through the Russian inland waterway system through the pandemic. And we've had our challenges with it.

There are not projects in our queue that are remotely similar to this one. The kinds of things that we're talking about now are factory development projects across multiple shale basins. There are deepwater developments that I think the track record on those is quite different.

I think the lessons on these really complex capital projects are that despite employing the best engineering and construction firms in the world, bringing in partners that have strong capability, they are really complex and challenging. And part of the way we mitigate that is we be very selective about the ones we do.

We walked away from the Kitimat LNG project because we, despite a lot of efforts to make that project better, we had concerns about execution in that kind of an environment and ultimately said we're not going to take on a project like that, particularly at this point in time. And so, part of it is the way you choose what you do. Part of it is continuing to learn and apply those learnings, many of which from a decade ago have been implemented into the TCO project, but some of which from the TCO project will be implemented and integrated into other projects that go forward of similar complexity.

Look, we're close to the finish line on this thing. We've got a full-court press on it to make sure that the commissioning is safe and reliable and we have a clean start-up. The lessons from that will be applied in every other project that we do.

Pierre Breber: I'll just restate the impact that Mike talked about. It's $2.5 billion [our share of dividends] at $60 [Brent], that's less than $1.50 a share. So clearly, we're down a lot more than that.

We talked about an earnings miss, we know that weighs also on the shares. At the same time, [it's] non-cash items, timing effects that reverse and discrete items that are non-recurring.

We feel good about the company's performance in the quarter in terms of how we operated safely and reliably, how we captured margin. We know, as Mike said earlier, we have these quarters where it can be messy, can be noisy. It's one of them, but the underlying company is very strong and healthy.

Doug Leggate: Agreed, it looks overdone Pierre. Thanks very much.

Operator: We'll go next to Irene Himona with Société Générale.

Irene Himona: (Société Générale) Thank you very much, good morning.

You refer in your comments to higher opex and DD&A from the PDC legacy assets having impacted Q3 upstream. Now that you own that business fully and you can sort of look under the bonnet, how are you thinking about your original synergy estimates on PDC opex and capex? And how long would you expect to take for those to start accruing to you in the results? Thank you.

Mike Wirth: Yes, Irene. I think that the reference was simply [that] these are additive versus prior periods. I wouldn't want anybody to interpret that somehow they were different than what we expected because the opex and the DD&A are not different than what we expected.

Synergy capture is good. We're right on track to capture all of the synergies. No change to the guidance. We're confident that there's upside and we'll realize that over time as we have on other transactions. We think there's additional operational, midstream and procurement synergies that we didn't build into our initial target. The capex synergy has been captured as well.

The nice thing about this, in a quarter where I appreciate Doug's view that maybe the reaction here has been a little overdone, we closed the transaction five months ahead of guidance, we pick up additional production for a bigger part of the year [and] the earnings and cash flow [that] go along with that. We've already paid off some high-cost debt. We're integrating [PDC] into our business now, and it's a very sound transaction that is going to deliver everything that we expected and then some.

Operator: We'll go next to Jason Gabelman with TD Cowen.

Jason Gabelman: (TD Cowen) I wanted to ask about what's going on in your Middle East footprint.

You've obviously had to take Tamar offline. I believe that's a fixed price asset that you're receiving, so probably not a large cash impact, but if you could remind us what the cash impact is and the ability to maybe re-route that gas somewhere else or offset those losses? And then how you think about the Eastern Mediterranean growth profile overall, if there's any change how you're thinking about it in light of the recent events over there? Thanks.

Mike Wirth: I'll take the second part of that and then ask Pierre to address the cash and production impact. It doesn't change our view on the development opportunities at all, Jason. This is a long-term play. It's a very, very large gas resource. We like some of the follow-on exploration opportunities in the region. We're working on the Aphrodite field in the waters offshore Cyprus to develop. We're working expansion projects that have been sanctioned on both Tamar, Leviathan and further expansion ideas on Leviathan.

We've got to take a long-term view, which is measured in years and decades. When you have things in the short-term that create the circumstances that we see right now, we have to be prepared to mitigate those risks and keep people safe and maintain the integrity of our operations. It doesn't change our long-term view on the attractiveness of the asset and the development opportunities. I'll let Pierre address the cash question.

Pierre Breber: We don't talk about our specific contracts and the numbers of them. But I think, in effect, you're right, there's some escalators tied to inflation. There's some oil price sensitivity, but it's within sort of a floor and a ceiling. These are regional gas prices that are well below international prices.

We don't know how long. We gave the guide on the production and the impact on cash flow is very modest. It's tens of millions of dollars in terms of doing the calculation. We'll just see where we end up in the quarter and how long it is shut in for.

Operator: We'll go next to Ryan Todd with Piper Sandler.

Ryan Todd: (Piper Sandler) Maybe switch gears a little bit to the Gulf of Mexico.

Can you maybe provide any update on an overall basis. Do you anticipate the addition of the Hess assets in the Gulf to have any impact on your approach to the basin in the coming years? And then you're scheduled to have 3 separate projects hitting at Anchor, St. Malo and Whale come onstream during 2024. Could you maybe update us on the progress of those projects and maybe the timing whether we should expect those in the first half or the second half of the year?

Mike Wirth: Sure. On the combination with Hess, I think we'll come back to you as we close the transaction and we integrate those. We're partners in a couple of projects that they operate. We both have lease positions out there. I think you would expect us to high-grade the exploration program as we look across a larger combined lease position, but we'll talk to you more about that as we go forward.

In terms of specific projects, yes, you're right. Mad Dog 2 actually saw first oil this year, and we expect peak next year on Mad Dog 2. You can refer to the operator for more on that.

Anchor and Whale are both expected for first oil next year.

Anchor is seven wells in total, two that will be online in 2024, two in 2025, two in 2026 and one then in 2027. The FPU is safely moored out there in the field right now. The manifold and pump systems and subsea manifolds are all fabricated. We've landed and tested the 20,000 psi blowout preventer. That project is moving along nicely. Production in 2024 is modest because there's only a couple of wells online. Think of it mid-year in terms of general timing.

I'd refer to Shell on the Whale project. First oil probably the latter part of 2024 and a similar kind of a profile where you've got a smaller number of wells online initially and then over the subsequent couple of years you're going to see additional wells come online. The production impact of that starts to show up in 2025 and 2026 in a greater way than it does in 2024.

Ballymore is actually first oil in 2025, not 2024, but that will come online in 2025. Simpler development: tie-backs to Blind Faith, three wells, two of which would be online in 2025. The third one would come online in 2026. Again, the production on that – a little bit in 2025 and then you'll see more of it in 2026 and 2027.

Pierre Breber: Ryan, just more broadly on Hess. We are not planning to hold our Investor Day at our usual timing. We'll likely either have just closed or will be in the antitrust review process. This is a big transaction impacting Gulf of Mexico but transforming the portfolio overall. We gave some guidance on potential asset sales also. You should expect us to do an Investor Day several months after we close and when we have time to really put together a combined business plan for our investors.

Operator: We'll go next to Bob Brackett with Bernstein Research.

Bob Brackett: (Bernstein Research) You've spent part of the week engaging with your shareholder base and making the case for the acquisition of Hess. Can you talk to, not details, obviously, but perhaps the tone of those conversations, the enthusiasm, anything that surprised you?

Mike Wirth: I'd say overall, and of course, I was out, Pierre was in some separate meetings than I was, but I was out in a number of meetings with John Hess, sometimes with larger Hess shareholders, sometimes with larger Chevron shareholders.

I would say, in general, people see the long-term value proposition very clearly here. I think they see it as a combined company that is stronger and one that is set up to be stronger for longer with the ability to really sustain cash distributions to shareholders in a very consistent, predictable and durable fashion long into the future. There's no doubt about that.

Some of the questions, on the one side, did you get a high enough price? On the other side, did you pay too much? There was tension in that, to be honest, during the negotiation. It, as we mentioned, has been going on for some time. John and I have been looking for a way to do a deal that is actually one that's good for both sets of shareholders and it's not easy because it's a great asset and the market recognizes that value.

I think you can find nuances from people who either held one of the stocks or the other for certain reasons, and maybe this wasn't exactly what they expected. But broadly speaking, I would say, people see the long-term value creation. They see the transparency to resource depth to production growth. The fact that you now have, with Hess, a much more diversified set of assets attached to their portfolio, which de-risks anyone of those assets, and it brings forward cash distributions to their shareholders meaningfully that would have still been several years into the future. For the Chevron shareholders who were wondering what comes next after what they can currently see over the next several years in our portfolio, rather than us pointing to a range of potential answers to that and say, we'll do the best of these – and we've got plenty of organic investment opportunities we're working on – I think it gives some confidence and certainty of what underpins that for the future. Broadly speaking, those are the kinds of discussions that we've had.

Operator: We'll go next to Neal Dingmann with Truist.

Neal Dingmann: (Truist Securities) My question, Mike, is more on your shareholder return.

You continue to have great financials and the shareholder return, both on the dividend and the buyback side continues to be quite high paying out a bit over 100% of your free cash flow. I'm just wondering, as you continue to have the growth opportunities ahead you do, do you see any change in that shareholder return, particularly on the share buyback? Or you continue to try to balance kind of the growth and buyback programs that you have now?

Mike Wirth: We've had a very consistent set of financial priorities for many, many years. The first of which is to sustain and grow the dividend –36 consecutive years now of per share dividend payouts, for the last five years has been a 6% CAGR. Actually, the last 15 years have been a 6%CAGR and an announcement of 8% early next year, subject to Board approval. I think there's a strong track record there you can expect to continue.

Second is to be disciplined in organic reinvestment into the business to grow those cash flows. You can be confident that we will continue to be disciplined in that reinvestment to drive returns and value.

Number three is a strong balance sheet. Pierre mentioned we're single-digit net debt ratio today. That's lower than we have guided to over time. Over time, you can expect the balance sheet to move back towards the 20% to 25% gearing range that we've identified as where we're comfortable through the cycle.

And then the fourth are the share repurchases. We've got a range now of $10 billion to $20 billion. We're at the high end of that range when we close the transaction with Hess. We're at $17.5 billion annually today, that's 5% to 6% of our float each and every year. I won't go through the details, but we've indicated we can sustain that in a lower price environment and that's where the lower end of that range would apply, and certainly, in a higher price environment, which is where we find ourselves today, we're at the high-end of that range.

We would expect to be consistent, predictable and to sustain that – consistent and durable being the key words here. I think the broad framework is likely to remain unchanged. I think our behavior will be very consistent with what you've come to see from us historically.

Operator: We'll go next to Alastair Syme with Citi.

Alastair Syme: (Citigroup) Mike, can I go back to Hess?

For several years, Chevron has looked a bit different to the other integrated oil companies in terms of the low downstream exposure. And of course, now you're re-weighting even further to the upstream. So does that balance bother you at all? Or maybe how do you think about what an integrated oil company is?

Mike Wirth: Yes, Alastair, the short answer is no, it doesn't bother me. We actually have been becoming a more downstream-weighted company the last several years. That may not be obvious to most people, but our capex into the upstream has been below our depreciation, so our upstream business has been declining as a percentage of capital employed.

In the downstream, we've made some big investments. We acquired a refinery in Texas. We acquired a renewable energy company. We've invested in new petrochemical facilities. We got two more of those petrochemical expansion projects underway right now.

We had gone from 85-15 weighting upstream to downstream & chemicals to 80-20 over the last few years. When we close this transaction, we'll be back at 85-15 which is where we've historically been. That reflects a fundamental view that we believe that over the cycle, returns in the upstream are likely to be structurally higher than in the downstream primarily because refineries are hard to close, they get built for reasons other than just pure economics and governments tend to intervene in transportation fuels markets, in particular when prices are high, which kind of takes you out of full cycle economics, and they kind of tend to clip the peaks off of those. Whereas in the upstream, you've got a declining resource base and you've got growing demand, and the fundamentals rebalance more quickly. You remove a little bit of investment and you see decline takeover and you see demand continue to grow. Markets that get imbalanced in the upstream rebalance more quickly.

We also have been more oil-weighted than some of our peers. Fundamentally, that reflects a view that there are more alternatives to substitute for gas, particularly in power generation, than there are for liquids in transportation.

Those are kind of high-level drivers of why our portfolio has been constructed the way that it is. We want to be an integrated company. We think there are real opportunities to capture economic value through integration, to build the capabilities to run our entire business by bringing capabilities, technology, skills to bear across those different segments.

Our peers are all weighted more to the up than the downstream. The ratios are a little bit different. We've long held those views and constructed a portfolio that reflects them.

Jake Spiering: I would like to thank everyone for your time today. We appreciate your interest in Chevron and your participation in today's call.

Please stay safe and healthy. Katie, back to you.

Operator: Thank you. This concludes Chevron's third quarter 2023 earnings conference call. You may now disconnect.