2023 Chevron Investor Day

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This presentation is meant to be read in conjunction with the 2023 Chevron Investor Day Transcript. All materials are posted on chevron.com under the headings "Investors," "Events & Presentations."

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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."

Introduction

Roderick Green: (Slide 1) Welcome to Chevron's Investor Day, held here in New York City and streaming on Chevron.com. I'm Roderick Green, General Manager of Investor Relations.

(Slide 2) Today's meeting will have three sections – starting with Higher Returns, followed by Lower Carbon and closing with Winning Combination. In each section, our executives will lead with brief comments and a few slides, reserving most of the time for Q&A with sell-side analysts. We'll have 10-minute breaks in between. The full presentation is available on Chevron's website.

(Slide 3) Before we get started, please be reminded that this presentation contains estimates, projections, and other forward-looking statements. These statements are subject to certain risks, uncertainties, and other factors that may cause our actual results to differ. Please review the safe harbor statement on the screen and available online.

Now, I'd like to introduce our Chairman and CEO, Mike Wirth, and EVP of Oil, Products & Gas, Nigel Hearne.

Higher Returns

Mike Wirth: (Slide 4) Thanks, Roderick.

Good morning and welcome everyone to Chevron's Investor Day on a snowy Tuesday morning here in New York. It's good to see everybody in person and to welcome those of you that are joining us online.

(Slide 5) During the past few years, the world has experienced energy markets both in surplus and in shortage.

We've seen prices so low as to challenge the viability of energy companies and so high as to be a top issue in election polls.

We've seen periods with society predominantly focused on climate change and others with attention concentrated on keeping homes warm and factories running.

This illustrates our fundamental belief about energy investment, which must balance economic prosperity, energy security and environmental protection.

Affordable energy is vital for economies to flourish. Reliable energy is essential for national security. And we all have a stake in a lower carbon future.

When decision makers over-index on any one of these, there is a risk of unintended consequences and unsustainable outcomes.

Through the turmoil, Chevron has remained consistent. We believe that energy should be affordable, reliable and ever-cleaner.

And we're taking action. With plans to grow both traditional and new energy supplies while safely delivering higher returns and lower carbon.

(Slide 6) Our approach is clear and consistent. Apply capital and cost discipline to a portfolio of advantaged assets to safely deliver lower carbon energy to our customers and superior cash returns to our shareholders.

We're focused on businesses and regions where we can leverage our strengths. And we intend to grow both traditional and new energy businesses because the world's demand for energy is growing too.

Today you'll hear how Chevron, with strong free cash flow, lower carbon operations and new energy solutions, intends to sustain higher returns in a lower carbon future and continue to win investors back to energy.

(Slide 7) Chevron's 2023 capex budget is up more than 30% from last year as activity builds and costs rise. This year's affiliate capex is down by about a half a billion dollars as our project in Kazakhstan winds down spending.

Our guidance range is unchanged as affiliate capex is expected to decrease further leaving room for future capex increases up to another billion dollars.

In a cyclical commodity business, capital discipline always matters.

Our objective is to grow our business in a capital-efficient manner, driving productivity improvements to mitigate inflation, and holding onto our hard-earned gains in capital efficiency, returns and free cash flow.

You know us by our track record. You can count on us going forward.

Now, over to Nigel to talk more about our targeted improvements and performance enhancements.

Nigel Hearne: Thanks, Mike.

(Slide 8)

We're growing margins and volumes. Over the next five years, we expect unit upstream earnings to increase over 50% at flat prices.

At the same time, we have confidence in exceeding our five-year annual production growth guidance of over 3% led by the Permian, Tengiz, Gulf of Mexico and Other Shale & Tight assets.

Production growth is an outcome of driving returns from our advantaged portfolio.

Our continued focus on capital discipline and efficiency combined with growing volumes and improved per-barrel margins is expected to deliver stronger financial performance.

(Slide 9) The Permian continues to deliver higher returns, production growth and lower carbon intensity.

We constantly optimize our development plans for returns and incorporate learnings from across the Permian Basin.

Last year, performance in the Midland Basin exceeded our plans but fell short in the Delaware primarily due to higher-than-expected depletion after completing long-sitting

DUCs. With our large inventory, we're able to shift our operated program to more single bench, high-return developments in New Mexico. Our guidance remains to achieve one million barrels of oil equivalent per day in 2025.

We're managing cost pressures and continuing to leverage technology to drive performance improvements.

Examples include Simulfrac, where we perform completion activities on four wells at the same time, and optimized gas-lift, which lowers downtime, minimizes workovers and improves safety.

This year we'll be running four grid-powered rigs and one natural gas driven frac spread. Around 40% of our grid-supplied power will be from wind and solar.

(Slide 10) At TCO, we've shifted to commissioning and start-up of WPMP and expect to begin operations before year-end. In the past month we have tied-in the fuel gas system and tested the first gas turbine generator.

WPMP mitigates field decline by converting field gathering stations from high pressure to low pressure through a series of mini-turnarounds that will begin later this year.

FGP is expected to start-up by mid-year 2024 and ramp-up to capacity by year-end.

Cost guidance for the project is unchanged.

In 2025, the first full year of FGP operations, TCO production is expected to reach over one million barrels of oil equivalent per day and generate for Chevron about five billion dollars of free cash flow at $60 Brent.

(Slide 11) In the deepwater, we have a robust portfolio that's delivering strong returns with low carbon intensity.

In the Gulf of Mexico, we expect production to grow to 300 thousand barrels per day by 2026. The Anchor topsides have been successfully set on the hull. First oil is expected next year along with the Whale project. Ballymore and other brownfield projects that leverage our existing infrastructure are also on track.

In Nigeria, we've extended three of our key deepwater leases and will begin a 37-well infill program on the Nigerian shelf. On the Angola shelf, we achieved first oil from one of our new capital-efficient, factory-style platform designs.

Australia shipped a record number of LNG cargoes in 2022 as Gorgon and Wheatstone together delivered first quartile reliability. The Gorgon Stage 2 project is expected to be ready for start-up in the coming weeks and the Jansz-Io subsea compression fabrication is underway.

Our assets in the Eastern Mediterranean are highly reliable and low in carbon intensity. We continue to develop our resource base there and further strengthen it, for example with the recent Nargis discovery.

(Slide 12) With over 175 trillion cubic feet of net natural gas resource, we're building flexibility into how we connect our growing natural gas production with customers.

Today, value chain optimization is allowing us to increase our margins through effective utilization of our assets, shipping and access to preferred markets.

We're aiming to develop a global network to maximize the value from our advantaged resource. In the second half of this decade, we plan to expand our LNG portfolio. We're developing options to supply LNG to Europe and Asia through the agreements signed last year for LNG from the U.S. Gulf Coast and potentially from our Eastern Mediterranean assets.

(Slide 13) In our downstream and chemicals businesses, we remain focused on managing costs and optimizing margin across integrated value chains.

We had record 2022 downstream earnings, which included about $2 billion of realized self-help. We expect to carry this momentum forward, and after our growth projects come online, we anticipate earnings to average over $5 billion at mid-cycle margins.

We believe in the long-term fundamentals of chemicals and are investing in world-scale projects with advantaged feedstock, a competitive cost & capital structure and the ability to deliver strong project execution. Our U.S. Gulf Coast and Qatar projects both fit these criteria.

Our refining system continues to evolve. We're expanding capacity at the Pasadena refinery to handle more oil from the Permian, and we're doing capital efficient unit conversions to process renewable feedstocks at El Segundo and Pascagoula. With the renewable diesel project in Geismar expected online next year, our renewable fuels capacity will increase by 30%.

In summary, we're focused on cost and capital discipline, increasing our margins and growing our business.

Let's move into Q&A. Please state your name and your company and limit yourself to one question and one follow-up.

Mike Wirth: Sam was quick on the move over here, so we'll start over on this side with Sam.

Sam Margolin: (Wolfe Research) Morning, Sam Margolin at Wolfe Research. Thanks for taking the question. I'm sure we'll spend plenty of time going over your organic opportunity set, and I don't mean to diminish that, but I do want to ask about M&A, because it comes up most of the time. Capital efficiency in the industry has peaked, it may not be spiraling down, but it's off the peak. The equity market is interpreting that as an inventory issue, but Chevron's made macro commentary in the past that there's plenty of resource in the world, so this is a dislocation that seems like it would be an opportune time for M&A, especially since you have no debt. So I guess framed that way, how are we thinking about M&A right now?

Mike Wirth: Sam, you probably won't be surprised, I'm going to give you a high-level, general answer here. I think we've got a track record in M&A that speaks for itself. We've done well-timed deals [for] more than the time I've been in this role, over many decades before, to grow the company. I think our proficiency there has been one of the keys that's made us a survivor and one of the strongest companies in the world today.

We're always looking. We've got a team that scans opportunities both in the traditional space and the new energy space constantly. We've got an inventory of over 1,000 companies that we are looking at on an ongoing basis. They get run through a set of filters on asset quality, strategic fit, value, willingness to transact, etc. We know what companies we like, we know at what values we might like those companies, but we don't have to be in a hurry. We don't have a resource issue within our portfolio. We don't have a gap that we feel we need to fill. So, we'll be patient. We'll look for the right opportunities at the right time.

I think our track record says you can expect us, over time, to execute transactions. History books aren't filled with great deals that were done relatively high in the commodity price cycle, and I would argue that we're relatively high in the commodity price cycle right now. Valuations have recovered, companies are proud of their assets, and I'm not sure that now is the time you're going to see a lot of deals done. It is still an industry that is highly fragmented. We're one of the biggest companies in this industry and we've got 2% market share of the global oil market. There is room for consolidation in different parts of the value chain, different parts of the world, but we'll look for the opportunities that we think make sense and create value.

I can see you've got a follow-up question on your mind. You're kind of leaning in on me.

Sam Margolin: (Wolfe Research) Sure if I'm prompted I can come up with one. I'll just ask about your gas position in North America because it's quite large. Again, I'm sure people will go over the Permian later. You had the dot plot on the Haynesville, prices have been inviting and then disinviting activity there throughout the past 12 months, and then there's an LNG option value too. How do you think about your natural gas position in the U.S., the structural gas story in the world, and then how to commercialize it?

Mike Wirth: I'll let Nigel take that one. He's done a lot of work on our gas strategy over the years when he was in Australia and in other roles, so why don't you speak to that?

Nigel Hearne: Thanks, Mike. We do have a great natural gas position in North America primarily from the Permian, but also as you saw, we've added a rig line in the Haynesville. I would say that's not driven by short-term pricing, it's driven by long-term fundamentals on the outlook on the market. It ties to the LNG position that we've taken for offtake on the Gulf Coast and we've got a nice, growing natural gas position around the world that allows us to combine into a portfolio that can have flexibility to either access Asia or Europe. We pointed it towards it – how do we take advantage of our gas position we have today, the LNG positions we've already signed out, and then complement what's already in Australia and West Africa? We have [over] 20 TCF of [net natural gas] resource in West Africa. We have two offtake positions there. And then, potentially towards the end of the decade, there's the option to add expansion in the Eastern Med as we think about, what are the right options, to take advantage of our resource position there.

Mike Wirth: Okay, let's go over here on the aisle.

Nitin Kumar: (Mizuho) Good morning, Nitin Kumar with Mizuho Securities. I want to, maybe, unpack the Permian DUC issue that you noted in the Delaware Basin. Your solution seems to be move to single bench development to go back on track to your development plans. What I really want to try and understand is, was this a communication issue between zones as the solution seems to suggest, and if so, when will you be going back to those zones? And what do you expect to see at that point?

Mike Wirth: Let me take a first crack at that and then I'll have Nigel get down into some of the specifics, relative to go forward plans.

I hope you notice that the headline is our production guidance is unchanged: 3% compound annual growth rate over the next five years, Permian a million barrels [of oil equivalent] a day by 2025 [and] 1.2 million [barrels of oil equivalent per day] plateau later in the decade. We haven't changed our production outlook, at all.

We learn every year in the Permian. It's a great, big basin – it's multiple basins. You've got the Midland and the Delaware, then you've got sub-basins within each of those, and there is not one game plan that applies everywhere. It's not a homogeneous geologic setting. There's a lot of heterogeneity. Where single bench may work in one area better than multiple bench, there are other areas where the reverse is the case. We highlighted some of the elements of the go forward plan that we have a lot of confidence in, but we learn every year and we evolve every year. Some years those learnings are maybe more evident to you, but they're always going on. This is a case again as we look at the learnings over the past 12 months, so maybe you can talk specifically about some of the basin learnings, Nigel.

Nigel Hearne: Mike, thanks for clarifying the guidance. Our production targets are really a function of our capital and cost discipline. There's a slide in the appendix that I think is worth taking note of. As I think about our production goals in the Permian, I really think about them in three tranches:

1. The first is really through our strong royalty position where we have a mineral interest. It's a significant portion of our production, with a mineral interest in a large acreage position, which is a strong competitive advantage.
2. We have our NOJV [non-operated joint venture] program where we partner and learn from our competition, where we have working interest and we collaborate to figure out how to do the best across the entire basin. That provides interesting learnings.
3. Then we have our COOP [company-operated] program. Our COOP program represents about 55% to 60% of our overall production.

I [will] summarize the two regions first and then get into the specifics of your question. In the Midland Basin, our performance exceeded plan. In the Delaware [Basin], we fell short. There are a few reasons, primarily driven by depletion. Firstly, we saw some wells impacted by horizontal interference and long-sitting DUCs. We saw some vertical interference where we piloted multi-bench development, primarily on the southern area of Delaware Basin and the western area of the Delaware Basin. I want to point to the basis design because, the vintage of these wells, many of them were drilled in 2018 and 2019. They built a long inventory of DUCs into 2020 and it was only during 2022 that most of that DUC inventory got worked off. On the bottom right [of slide 17], the [dark blue solid] line represents the aggregation of those three things across all of the wells. Around 70% of those wells were long-sitting DUCs. That really exacerbated the interference problems that we talked about, or the communication was the word you used. If you take that inventory of wells out, and just look at the wells that didn't have that impact, what you see is the light blue line. The light blue line is our forward plan. That forward plan does not have long-sitting DUCs. It is more focused on single bench development. We've reconfigured our well spacing, so that's what we've got built into our forward-looking plan. It's why I feel confident in our production outlook. It does have some impact, relatively moderate, in our outlook. You will see that we're drilling deeper benches because we're targeting returns. You'll see more rig moves per section. Both of those add a little bit to cycle time, but again, it's not a significant amount and we've built that into our forward-looking design plan.

I feel confident in our performance. I feel confident we understand what happened in 2022. We've applied the lessons learned. We're constantly learning and improving and constantly looking to optimize our basins. I feel confident in the outlook that Mike mentioned.

Mike Wirth: So somewhat of a unique set of circumstances that came together there and those learnings applied going forward.

You have a follow-up?

Nitin Kumar: (Mizuho) Thank you for prompting me. If I can look at slide eight, your mix of low-decline, offshore assets changes dramatically by 2027, which is your forecast. From your seat, how do you maintain the treadmill at that point? You have a lot of shale assets contributing to your overall production slate at that time, they're high decline, so I just want to understand how do you think the production profile could look like? You have 3% CAGR until 2027. What does it look like in 2028, 2029? I'm not asking for guidance, but just shape.

Mike Wirth: There's a slide in the appendix [slide 16] that we could pull up that talks about longer-term growth. We've got multiple growth assets. I think this is the key thing and sometimes I talk to people that may not fully appreciate that. As you look at the left-hand side of the slide, we've got what we would classify as our base production assets and it pulls the growth assets out and shows them on the right-hand side. You can see very shallow decline in that part of the portfolio largely because these are facility-limited, not field-limited. You can think LNG plants, you can think Kazakhstan, where you've got big surface facilities. We've got some level of drilling that's required to keep those facilities full, but we've got big resource positions that underline those. On the right-hand side, you can see the Permian's going to grow a lot. The Permian growth doesn't end in 2027. We've got decades of inventory in the Permian. You can see TCO coming on by then. [In the] Gulf of Mexico, Nigel mentioned, Mad Dog 2 starts up this year, Anchor and Whale next year, Ballymore in 2025. We see more in the Gulf of Mexico, and then Other Shale & Tight is a significant part of the portfolio. There's a balance in the growth side of this.

The other thing that I would encourage you to think about is with this large, low-decline base, as you start to build up a very large position in the Permian, I'll just use that as an example, any given well has a rapid decline curve, but that's got a long asymptotic tail and you start to stack up dozens, scores, hundreds and eventually thousands of those long tails, that becomes a relatively shallow decline, large tranche of production. It doesn't take a lot of drilling on top of that to flatten out that set of long tails of production. That's why we talk about a plateau in the Permian for quite some time because we can actually moderate the amount of investment that's driving growth, and hold the plateau flat with even less capital, and allow that to spin off even more free cash flow. We are not falling off the edge of a cliff anytime soon, let me just finish it with that.

Nigel Hearne: If you go beyond 2027 and you look at some of the acreage position in the Eastern Med, we've got six blocks in Egypt, we've got an exploration program, we've got an appraisal well in Cyprus. We'll come to some form of concept selection towards the end of this year around Eastern Med expansion. We've got some of the strongest lease positions in the Gulf of Mexico with great infrastructure, so how do you tie back to existing infrastructure? There's another slide that shows our shale & tight is beyond just the Permian in the outer years. Some of that's a little bit less mature, it's in appraisal phrases or just coming out of appraisal phases, but you see a lot of that ramping up. I think we've got a strong, diverse, complementary asset base for the next five years. If you actually look beyond, we've got a nice queue of opportunities too and that strong resource base.

Mike Wirth: Okay, I saw Doug and then going to go to Biraj and I'm going to go to the back, I see Jeanine with a hand up.

Doug Leggate: (Bank of America) Thanks, Mike. Good morning, Doug Leggate with Bank of America. Two, can I take two? Is that okay? My first one is on the cadence of the free cash flow growth. I mentioned this to Nigel earlier. You mentioned the $5 billion of free cash from Tengiz in 2025. What is it currently? How does the cadence play out over that five-year period through 2027?

Nigel Hearne: The free cash flow growth is approximately $4 billion in TCO, $3 billion in the Permian. I use the Gulf of Mexico as an example where we're not giving free cash flow guidance – that's 100,000 barrels a day of high net cash margin barrels. And then you've got petchem growth towards the 2026, 2027 time frame. I know you may ask about petchem margins today, but that's not how we invest, right, if you think about the long-term fundamentals of chemicals. All of those are adding to that free cash flow.

Doug Leggate: (Bank of America): Thanks for that, especially on TCO and on the Permian. That's really helpful. My follow-up is on slide eight. It is the BOE margin slide. Given the significance of the Permian, there's obviously a lot of U.S. gas coming with that. If I check back the last time oil was around 60 bucks, first quarter of 2021, you did about $9 margin looks like. I guess my question is what are you assuming for gas in the U.S. and not margin expansion because obviously the mix is skewing, you know towards gas domestically.

Mike Wirth: Doug, we've not really changed our long-term price assumptions for oil, for gas, for NGLs, for refining margins. We're in a period of time where we've seen strength in a lot of these different commodities, but fundamentally, we believe that we're going to revert to mid-cycle margins over time. You do see a little bit of a mix change in the Permian over time, but the margin expansion is really driven by lower cost per barrel. Opex per barrel down 10% over that period of time, DD&A, we're much more capital efficient. You were around when we were spending $40 billion a year a decade ago. We're spending a fraction of that today. DD&A per barrel is down 20%. You're seeing per barrel reductions and costs, we're adding higher margin barrels into the portfolio and that net cash margin really just expands as a function of both of those. I would encourage you not to look at the mix effect and worry too much. You got a gas price, but it's really about cost efficiencies and scale as we start to see some of these volumes really come on.

Okay, Biraj and then Jeanine.

Biraj Borkhataria: (RBC): It's Biraj Borkhataria, RBC. Thanks for the presentation and taking my questions. The first one was on the base slide you showed again the 1.5 million barrels a day. You name check Nigeria and some of the work you're doing there in terms of extending the base. Could you just talk about operating in that environment because a number of your peers have sort of intimated that it's not workable given the security challenges and some of the things going on there and that forms a reasonable chunk of that base number.

Mike Wirth: It's a reasonable chunk. It's not the largest chunk by any means. We've been in Nigeria for a long time, Biraj. We've had a very successful joint venture business there and a lot of success out in the deepwater in Nigeria. We're a little less exposed to the swamp than some of the others and the issues that you talk about tend to be more challenging onshore than they are offshore. Our portfolio over time has kind of increased our offshore position and we've got an important, but not an enormous, position in the onshore as well.

We operate in a lot of difficult places. It's part of the business and I think we've operated very well there. We've seen some significant progress in terms of recovering some arrears in Nigeria that we've been looking to recover and so it's an important part of the portfolio. The operating challenges are things that our people manage. They work hard every day to do that.

Biraj Borkhataria: (RBC): Thanks for thanks for the color. The second one was on TCO. You mentioned it's on budget. I think in the past, it's been a while now, but you previously had a contingency number within the budget because of some costly increases previously. Is there any color you can give on how much of the contingency have you eaten through and how confident are you that would be maintained?

Mike Wirth: Nigel was there recently. Why don't you take that?

Nigel Hearne: I visited several times the last few years. I was there in January most recently. A lot of the risk in this project is behind us. If you think about mobilizing people, mobilizing equipment, this no longer looks like a construction site – construction's complete. We're now in the active phases of system completion and commissioning and start-up.

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Right now, we're getting focused on the high pressure to low pressure conversion of the field. That's what improves well deliverability. That's where a lot of the work and focus is today. It's commissioning utility systems that will allow that [conversion] to happen later this year. As we improve well deliverability, we'll provide more supply for the next train and gas compression facility at FGP, which will start-up towards mid-year [2024] and then begin to ramp-up.

It's complex. The start-up is a lot of activity, a lot of work to do. We've still got about 20,000 people there working, so a lot of activities ahead of us. We have turnarounds to manage as part of our base business. We have a turnaround in the third quarter of this year. We have one just before we start-up FGP next year and we have one between the ramp-up phases. I think if you look at the project schedule, a lot of the risk is behind us. We remain on budget with the project schedule itself and we're focused on a safe and reliable start-up of those assets.

Mike Wirth: Okay, can we get a microphone to Jeanine back here on the aisle.

Jeanine Wai: (Barclays) Hi, good morning, Mike, Nigel. Thanks for all the time and detail today. We appreciate it. Two questions if we may. The first one's on the Permian and the second one is on Eastern Med. On the Permian, love all the information with the type curves and giving us an understanding of what was going on in 2022. Can you maybe provide a little commentary on the cost side of things? I know you reiterated the production targets. I think prior thinking was it'd be about $4 billion a year or so that you would spend in the Permian, and when you put together everything and what you've learned on productivity as well as inflation, anything related to facilities, is $4 billion a year still really the number?

Nigel Hearne: I'll start with saying we are seeing some inflation pressures in the Permian. We see inflation around the low-teens, but a point I'll make is we absorbed a lot of that last year. We hit development cost of less than $8 per barrel despite some inflationary pressures last year. We're continuing to develop and improve and constantly looking for different ways to do that. I've been there twice in the last four months. I saw some great examples of innovation and improvement.

Our guidance is just going to be over $4 billion through the period. We do continue to see some of that pressure, and some of the adjustments I told you about our development plan, we'll see some marginal changes on cost, but still within that guidance range that we gave previously.

Mike Wirth: Jeanine, maybe just to add a little bit on that. All of our program for this year is already contracted: drilling, completions, crews. There's no risk in terms of execution. We tend to have contracts that are indexed to market indices and they periodically will adjust. We've actually seen costs that are lower in terms of some of the cost pressure than if you were out in the spot market contracting for services in real-time. We're also seeing technology and performance improvements to the points that Nigel made. I would suggest that if you're thinking about modeling this, I said overall capital guidance for the company's unchanged, production guidance is unchanged. Permian think about it in the $4 to $5 billion range, which is actually the guidance a couple of years ago. Last year I think we said $4 [billion], year before that we'd said $4 to $5 [billion], it's still in that $4 to $5 [billion] range.

Jeanine Wai: (Barclays) Great, you know we love our modeling, so thank you for that. On West Africa, your slide indicates that it's supporting the base business. You also cited that you have over 20 TCF of [net natural gas] resource there. Are we supposed to interpret that slide as there's not really much growth opportunity there? We know you've got Angola, you've got the Noble assets there with the EG LNG plant there that is meant to twin. Well, it's not meant to twin, it's available to twin and you've got great resource there. So just wondering kind of what the growth opportunities, if any, are available in West Africa? Thank you.

Nigel Hearne: It's part of that base decline conversation. The focus is we've got significant infrastructure invested both in Equatorial Guinea and in Angola. The focus is on affordable and timely supply of gas. I'll draw your attention to that small-scale, fit-for-purpose platform in one of the photographs. It's really about how do you help create a fit-for-purpose, factory-style development to keep those gas assets full whether they be oil or gas. Both of the focuses is keeping each infrastructure full. We've got more resource in offshore Equatorial Guinea and we've just signed some agreements to actually start to thinking about gas backfill for ALNG.

Mike Wirth: Okay, over here is Jason.

Jason Gabelman: (Cowen) Hey, Jason Gabelman from Cowen. I'm unfortunately going to ask another Permian question. You're suggesting higher capex, production kind of stable, and broadly Chevron espouses this value over volume mantra. How do you tie those to the fact that production is flat, capex is moving higher in the Permian Basin, but at the same time you're still a value over volume company because it seems like, at least in the Permian Basin, there is a bit of, well we want to hit this volume target, but we're going to increase capex to do so? And I have a follow-up. Thanks.

Mike Wirth: The capex guidance, as I said Jason, is what it was two years ago, which was $4 to $5 billion to get there. It's within the range of a little bit of inflation coming into the thing, but we're not talking about a big program change. If you look at the ramp on rigs, you look at the ramp on completions, you look at the ramp on POPs, it's consistent with what we've been doing. You've got a little bit of inflation that's going to chew into returns. It's still the highest return capital dollar that we can put to work. If it wasn't, then you would see you'd see a change to that.

Jason Gabelman: (Cowen) Right. That's really helpful. That was just based on feedback we've gotten from investors. They were asking about that.

The second one is also something that's been asked just about the global gas footprint and building that out. As you think about Chevron, it doesn't have an LNG or gas trading business similar to some of your peers, and your largest U.S. peer is building out a trading business. As you think about the ability to compete on global LNG and global gas and be able to sanction new projects, does a lack of that trading business within the company impact your ability to sanction certain projects and capture returns that you think would otherwise be available? And if so, is that something you would be willing to look at expanding a trading business moving forward?

Mike Wirth: I want to correct the premise of your question. We do have a gas trading business. We do trade LNG. We may not talk about it the way some of our peers do, but we absolutely have a gas trading business and it does not in any way, shape or form constrain our investment opportunities.

Ryan Todd: (Piper Sandler) Maybe a question first on the buyback. You increased the buyback guidance a little bit in terms of the range over the five-year plan. You've been pretty strategic and cautious, I would say, over the years in terms of walking as far as you felt like the marketed de-risked or you could kind of conservatively have confidence in the sustainability over the period. What has changed over the last 12 months that provided you increased confidence to increase the buyback range either from a macro environment or from your own company operations?

Mike Wirth: Let me just frame the buyback within our four financial priorities, which have been a long-standing.

Number one is to increase the dividend. 36 years in a row we've done that. Over the last five years, 2x the dividend growth of our nearest peer, including growing the dividend through COVID-19 when others did not or even cut it.

Second priority is to reinvest in the business. We've been talking about that to generate cash flow. 10% compound annual growth rate on free cash flow over the next five years.

Priority three is the balance sheet. We've got the strongest balance sheet amongst our peer group. [3.3%] net debt. We ended the year with nearly $18 billion in cash on the balance sheet. We need about $5 billion to actually run the company, so you can think of that as $13 billion of cash on the balance sheet that doesn't necessarily need to be there. With that low net debt, we got $30 billion of debt capacity before we start to tickle the bottom end of our guidance range on where we would see ourselves through the cycle.

We've got capacity, is the key point here, and you'll see when Pierre comes in here, and I'll defer to make sure we get to a lot of questions here, but we stress tested in a low-price case, we test in a higher-price case. What you see is that even if we're in a $50 [Brent] world for 2025, 2026, 2027, we can sustain a $10 billion buyback. If we're in a higher price world, which he'll show you is a $70 [Brent] case for those years, which may or may not feel high today, we can be at the high-end of the range or even have capacity to do more than that.

We've seen the financial health of the company continue to strengthen and we're in a position now to sustain a higher rate through the cycle. The last point I'll make is, we don't look at buybacks as something where we're going to be counter-cyclical, we certainly don't want to be pro-cyclical. We want to buy back steadily through the cycle. We've done that 15 of the last 19 years. We've bought shares back at an average price two dollars [lower] than the volume weighted average [price for] the entire 19-year period, including when we bought shares back in 2020, we bought shares back in 2021. We've had a track record here of steady buybacks through the cycle, and we think we've got the capacity to sustain them at the level we've indicated in the range.

Ryan Todd: (Piper Sandler) Thanks, and then maybe one follow-up question on Eastern Med. It's an asset that I think probably many of us that were Noble analysts used to spend a lot of time on pre-acquisition and have not spent as much time on over the last few years. But can you talk a little bit about the Tamar expansion? You know, what's happening with the Tamar expansion, maybe the timing on that? And then beyond that, how do you look at the long-term optionality? What are some of the of the potential outcomes that you're looking at? And maybe what are some of the key drivers or gating processes to further expand Leviathan or incorporate Aphrodite or the material growth opportunity there? So, any comments?

Mike Wirth: The headline is it's a beautiful asset, a beautiful resource, even better than we thought when we bought Noble. There is a lot of opportunity there for expansion and we're working on those now. including ideas to help bring LNG to Europe to help Europe with its gas supply challenges. Nigel referenced Tamar. Maybe you can say another word about that and also about Leviathan.

Nigel Hearne: Like Mike, I also like those assets. I like the assets we've got. It's a very high reliability, low carbon asset today. Tamar's producing at about 1.1 BCF a day. We've FID'd the project to expand it to 1.6 BCF a day that'll come online in 2025. Leviathan's producing at 1.2 BCF a day. We've got a great resource position, six exploration blocks in Egypt. We've got the appraisal well in Aphrodite, we found a discovery in Nargis-1 well, so strengthening our resource position, building out the infrastructure. There's a good, strong, regional market there that's growing gas demand and we continue to evaluate options for floating LNG as potential other avenues to access European markets. It's a fairly benign ocean, so in terms of floating LNG, it works. We'll evaluate those options towards year-end, finding the right commercial pathway for the current production we have, the resource position that's developing and the projects, and then the future development. I think it is a really nice asset today and it has opportunity for growth potential.

Mike Wirth: Tamar likely to come online, the Tamar expansion, early in the second half of this decade. Leviathan, as Nigel said, we got a couple options we're still looking at – that production is likely towards the latter part of the decade.

Paul, and then the other Paul.

Paul Sankey: (Sankey Research) Thanks, Mike. Paul Sankey, Sankey Research. Just listening to you on Eastern Med, I was thinking about global geopolitical risk. Would you think that your biggest risk is the Russia exposure that you have for transport through Kazakhstan? I know there's kind of threats everywhere, but would that be the number one thing that you're worried about? And is there the potential for you to develop alternate routes, which I think slightly came up last year as there was outright interruptions to supply as to whether or not you could find another way to get out. Is that the biggest risk that you face politically and I'm thinking in Australia there's risk, Eastern Med, kind of strangely, there doesn't seem to be so much risk, you've got the California government, you've got the U.S. government. I mean you name it. They're coming for you from more sides. What's your perspective on that?

Mike Wirth: I tend not to bucket the risks in the biggest risk and the second biggest risk, Paul, because they're everywhere and they evolve over time. And as you say, there's risks right here in this country that we face. Last year, specific to that pipeline, there were some interruptions. It had a very minimal impact on our actual production over the course of the year. Our people were able to manage through that in a variety of ways. It's a risk like many other risks that you cited, but it's one that's been managed very well and the Republic of Kazakhstan has been very engaged because it's obviously very important to the country. We work closely with government officials, we work closely with partners, there are a number of international partners in that consortium, all of whom have a stake in keeping that pipeline flowing, and it's important to world markets right now at a time when that production is needed. We've been on top of it. The impact has been almost de minimis to this point and we continue working hard every day.

Paul Sankey: (Sankey Research): Thanks. Is there any update on Neutral Zone? Thanks.

Mike Wirth: Yeah, we haven't talked about the PZ. We've got production back up, on a 100% basis, north of 150,000 barrels a day. We're looking at some different ideas on field development and expansion, different technologies. We'll be doing some pilots over the next year or two to look at some horizontal drilling, some other types of enhanced recovery technologies that may be appropriate. We'll talk to you more as we start to develop plans for further growth investments there.

Paul Cheng: (Scotiabank) Thank you, Mike. Paul Cheng, Scotiabank. Two questions, please. First, want to go back into LNG. I think historically Chevron and all the super majors took an integrated approach. You own the asset, you own the transportation facility. Recently, you signed a supply contract in the Gulf Coast, seems like a break away from that. So my question is that by the second half of the years, of the decade, when you start to expand your footprint again in the LNG, is the strategy going to be a more focused on the asset-light or that you still going to use the traditional model that you want to fully integrate? And also whether you are concerned because it does seems like that a lot of LNG projects coming on stream after 2025. I think a rough ton is probably 18, 19 million ton per year kind of capacity, so is that a concern?

Mike Wirth: Paul, we don't have a model that we must adhere to in terms of LNG development. You talked about the integrated, full value chain developments that we did in Australia. It was because there was really no alternative to bring that gas to market. We needed to be in every part of the value chain. If you look at the deals we've entered into in the U.S., we've got a lot of gas resource. There are plenty of people looking to build facilities on the Gulf Coast and we can enter into offtake agreements to shift the pricing for some of our production here from a Henry Hub price to an international LNG price without having to take on the capital investment and the capital risk in the midstream. Those tend to be lower return investments, just like some other midstream investments that we've tended not to go into. There are other people who that's their business model and that's what their investors are looking for and we can work with them to access the parts of the value chain where we can generate the returns that we expect and that are competitive within our portfolio and enter into commercial arrangements. We can approach LNG development in a variety of different ways, always looking at driving returns for our shareholders and taking advantage of the opportunities that each market can offer up.

Paul Cheng: (Scotiabank) And how about seems like a lot of capacity coming on stream, is that a concern?

Mike Wirth: It's like so many parts of this industry, Paul. You get surges of capacity and markets tend to get oversupplied and then they work that capacity off. LNG's been like that, petrochemicals, refining. Will there be too much LNG capacity at some point in the future? Probably. Will that be a structural impediment to investment for a short period of time at some point? It may be, but demand for LNG is growing, demand for gas in the world is growing, and I think you'll see as we saw in the last wave of projects, they tend to slow down when people start to get right up against financing and final investment decisions. If it looks like there's too many of these things coming all at once.

Paul Cheng: (Scotiabank) The second question is on inflation. I think everyone talks about their onshore. Can you talk about the offshore with what kind of inflation rate that you are seeing, since that's also a part of your future growth in the Gulf of Mexico and how that impacts your development pace?

Nigel Hearne: I highlighted the inflation rates primarily in the Permian and Mike made some good comments around how their indexed. Inflation rates more globally are in the low [to mid] single digits, Paul. Specifically, the Gulf of Mexico, all of our rigs for the near-term development are all contracted up, so we don't see any real change to that, but mainly in the low [to mid] single digits internationally.

Mike Wirth: Low to mid, probably.

Alastair Syme: (Citi) Alastair Syme with Citi. I was wondering if you could give us a quick map of the Other Shale & Tight piece. Just one question, just the overview of how those different businesses stack up.

Nigel Hearne: There's a slide in the appendix actually, if you could pull it up. If you look at our Other Shale & Tight assets, it was on the far right side of our growth picture, it's around 200,000 barrels a day of growth primarily driven by the three assets we have in Argentina: El Trapial is in development and the other two are just wrapping up appraisal. DJ Basin is the other primary growth. We've got rig lines being added there and activities. We're going to add almost 70% more POPs in 2023 than we did in 2022. Still a flexible base. Haynesville, we're just adding one rig line, part of our natural gas position. The other reason we're doing this, part of the depletion conversation we talked about earlier on, as offset wells and other operators are in the Haynesville. It's a good time for us to be there and it does attract good returns. And the Kaybob Duvernay, it's just holding flat. We've got a small amount rig lines running there just to kind of hold our base production. Alastair, does that answer your question?

Alastair Syme: (Citi) *[Inaudible follow-up question on Argentina]*

Nigel Hearne: Low development cost, high liquids yield, their issue is around risk. We've taken some commercial offtake positions with a pipeline deal that we've signed. There is commercial risk, but what I would say is this is a typical shale & tight development. We can pace our development as we see signals around that things are encouraging or that we see risk growing, we can either accelerate or slow down our activity. We're going to take a very measured, but deliberate approach to how do we develop the Argentine resource.

Mike Wirth: I'm going to try to squeeze in a couple more quick ones here. John.

John Royall: (J.P. Morgan) Hi, good morning. John Royall from J.P. Morgan. On the $15 to $17 billion capex guide, can you talk about the moving pieces there around not changing the guidance? There's obviously been a lot of inflation. What are some of the offsets going the other way? And then longer term, what do you think of as an optimal mix of growth versus sustaining once you're you know, no mega projects post-Tengiz.

Mike Wirth: I mentioned Kazakhstan coming down. That's one of the one of the things that allows us some more room. We've got other projects that are beginning to ramp-up in petrochemicals. Two petrochemical projects that we've sanctioned. Nigel just talked about some of the shale activity. We've got a project at our Pasadena refinery. There's a lot of puts and takes, John, and as we look at managing this for ratability and for execution, and we're committed to executing well, we're making trade-offs within the portfolio that allow us to stay within a disciplined range and a predictable set of outcomes. You'll see deepwater Gulf of Mexico projects. We talked about Anchor and Whale starting up next year, that opens up room in the years subsequent to that for other projects to come in. There are constantly projects that are reaching their peak spend, they're coming off their peak spend, and we trade those off as we stay within the guidance.

John Royall: (J.P. Morgan) Great. Thanks, Mike. And then I don't think you've gotten a question on Venezuela yet. So how are things progressing there? How long do you think it'll take to scale that up? And what's a reasonable expectation for Chevron's production in Venezuela?

Mike Wirth: It's very early days. We have begun lifting crude from Venezuela and bringing it to markets in the U.S. We've been running it at our own refinery and getting to supply other customers with oil. We've got some people on the ground, we've got some ex-patriots back in there. We've assumed some key management positions at some of the empresas mixtas and we've seen production respond. I mentioned at the at the fourth quarter [2022] call that production has gone from 50,000 [barrels of oil equivalent] a day to 90,000 [barrels of oil equivalent] a day, our share in the ventures. It's a little bit higher than that probably today. We're seeing some early progress, still focused on safety and asset integrity and we'll go slow there. The shift in policy by the U.S. government is relatively recent still. We've got questions about elections coming up and other things. I would expect us to go slow and we'll update you as we move along, but I wouldn't think of that as a real growth part of the portfolio until we've seen some more progress.

Behind John, and then Lucas on the aisle, and Neil we'll get to you too.

Phil Jungwirth: Thanks, Phil Jungwirth with BMO. Two questions on reserves. It was good to see the

(BMO)	production growth reiterated through 2027. Just wondering if you could talk about proved reserve growth or whether you could maintain proved reserves and just thinking about in terms of a lot of the major projects are booked and then you're somewhat limited under the five-year rule in terms of shale & tight and Permian bookings.
Mike Wirth:	We got an appendix slide on reserves and resource and I don't want to spend too much time on it. For over 10 years we've been at 99% and if you were to look at a one, three, five-year period there they're a 97%, a 102%. They really have been relatively consistent around that. On the resource side, we've gone from 65 billion barrels of [oil equivalent] resource 10 years ago to 78 billion [barrels of oil equivalent] today. Not only has it grown 20%, the resource quality is much better. 10 years ago, we had Canadian oil sands that we were unlikely to get to, we had Gulf of Mexico shelf, we had some North Sea, we had gas in the far northern reaches of Canada for Kitimat. A lot of the stuff that's going on in the portfolio was unlikely to compete for capital. It's been replaced with much better return, more likely to be developed resource. It's sitting there with 78 billion barrels of [oil equivalent] 6P resource to keep feeding reserves over time. We do have some things with the five-year rule that will govern how fast some of that comes into proved reserves, but we don't have concerns about reserve replacement.
Phil Jungwirth: (BMO)	Hey, thanks. And then my follow-up question would be on that 6P resource slide and as it relates to the Permian. Just wondering if the change in the development approach in the Permian that you'll be taking in 2023 and beyond would impact that 6P resource or more importantly the PV10 of that resource?
Mike Wirth:	The Permian resource has grown considerably over the last decade as you would imagine. It's come off just a little bit. Some of that growth, based on the learnings that Nigel referred to, we've actually pulled some of that resource back down. It's 27 billion barrels [of oil equivalent], so it's about a third of our total 6P resource. Just to put it in perspective, at last year's production rate that's 100 years of resource that we've still got sitting in the Permian. When I say we'll be working on this for a while, that's one of the reasons why I say that. The other thing I'll just reiterate, Nigel mentioned earlier, but this is royalty advantaged. It's 27 billion barrels [of oil equivalent], most of which has low or no royalty because it's fee property. The Permian is a resource I wouldn't trade for anything in anybody else's portfolio in the industry. Okay, I was going to get to Lucas and then Neil. We're just running a touch over time, so I'm trying to be really quick.
Lucas Herrmann: (Exane BNP)	My one question and in a way it goes back to Paul's question and it's really around you monetizing gas and LNG strategy. Firstly, remind me of your position in Venezuelan gas and I ask simply because of the efforts of the present time to keep Trinidad and Tobago full, not your asset obviously. Secondly, as I start thinking about, you know, your portfolio and ullage disappearing in other facilities, you know Egypt, Equatorial Guinea, Northwest Shelf, Indonesia, whirlwind tour. I mean, you have resource located around almost every one of those facilities and I would guess an opportunity to monetize. So Nigel, I mean the question is – does go back to Paul's – to what extent, you know, does that start to become front and center of minds in terms of monetizing gas in a very, should we say, financially beneficial way?
Mike Wirth:	We do have some gas resource offshore Venezuela. It's tricky as things are in Venezuela. But the broader point that you're making, Lucas, is I think one that you're going to see as a really durable feature of our development going forward, which is we've got resource

near facilities and we can do highly efficient brownfield development whether you're talking about secondary, tertiary, quaternary benches in the Permian, whether you're talking about keeping LNG facilities full around the world, Kazakhstan, the projects that we're doing there to maintain plateau. The intent is to look for, Gulf of Mexico, brownfield tiebacks and further tiebacks. The point you're making is something that is front and center in our planning and is highly capital efficient. And it's shorter cycle time and lower risk. I think you'll hear us talking a lot more about that in the years to come.

Okay, we're going to go to Neil and then I got to take a break or your next speaker is going to be in here and Nigel and I will still be sitting up here.

Neil Mehta: (Goldman Sachs) I'll be quick which is there was an organizational change that was made at Chevron and Nigel you're front and center in collapsing the upstream and the downstream organizations. Can you talk about what that has done in terms of your ability to drive your strategy forward? Thank you.

Nigel Hearne: Actually, it hasn't changed our strategy. What I think it does is it brings the best out of what we do in upstream, downstream, midstream together. We have identified value that existed between the segments that wasn't really available or wasn't material or visible before, but it's really about bringing this consistent and disciplined execution. Whether it be how we think about using existing infrastructure to monetize resources, to Lucas' point earlier. Whether we talk about how to drive asset class excellence – our shale & tight assets are now all organized under one direct report so you start to think about running those as a business proposal together. How do you leverage best practices. The same in our complex facilities in upstream and what we're seeing is there's things that are common across upstream, downstream, midstream. Turnaround excellence is an opportunity for us. What we're trying to do is bring out the best in what we do today and accelerate progress. With all those organizations being under one, it's a little bit simpler to actually do that. That's what I'm actually excited about.

Mike Wirth: We are going to take a slightly less than 10-minute break because I think we're going to restart on schedule. Coming in next will be Jeff Gustavson and Eimear Bonner to talk about New Energies and Eimear will talk about technology. Ask her about the Permian for those of you that got all these Permian questions. Eimear's doing a lot of interesting work in the Permian Basin. Thanks for joining us today, and we will break and be back in less than 10 minutes. I'll let the pushers get you guys back in the room when the time comes. Thanks.

Lower Carbon

Jeff Gustavson: (Slide 20)

I'm Jeff Gustavson and with me today is Eimear Bonner. I'll provide an update on the progress we're making on our lower carbon objectives and Eimear will share how technology is powering today's business and building tomorrow's.

(Slide 21):

Our strategy is clear: leverage our strengths to safely deliver lower carbon energy to a growing world. That means focusing on lowering our portfolio carbon intensity today while growing new, lower carbon businesses and solutions for tomorrow.

We're driving our renewable fuels, CCUS, offsets and hydrogen businesses forward, which we believe will also generate attractive returns and cash flows.

(Slide 22):

We're making progress towards our upstream CO_2 intensity reduction targets. We continue to prioritize the projects expected to return the largest reduction in carbon emissions cost efficiently. We have plans to advance over 100 projects this year to lower the carbon intensity of our operations, focusing on energy management, flaring reduction and methane management, among others.

Our goal on methane is simple – keep it in the pipe. In the U.S., we're already a leader in this space and plan to continue making progress through technology and partnerships.

(Slide 23):

We're continuing to grow profitable renewable fuels value chains. We're working with partners to secure diverse feedstocks and realize value in the oilseed crushing margin.

By building off REG's capabilities and assets, Chevron is now the second largest bio-based diesel producer in the U.S., and we're halfway to achieving our 2030 capacity target. We're using our existing distribution channels to place these volumes in markets to capture the highest margin.

In renewable natural gas, we're growing our partnerships with existing dairy farmers, while looking to expand our feedstock mix. We continue to grow our retail offerings with more stations in more states.

(Slide 24):

In carbon capture, we're taking early actions that aim to establish future large-scale, profitable projects. We're focused on securing pore space, creating regional hubs, and advancing capture technologies.

We're developing opportunities in the United States and Asia Pacific regions where there are concentrated emissions and good geology. We'll continue to take a disciplined approach, only selecting the best projects to invest in.

(Slide 25):

In the area of carbon capture, we've secured over one billion tons of CO_2 storage resource both on and offshore in the U.S. Gulf Coast near large, industrial emitters linked to natural gas value chains.

In the Asia Pacific region, we're working with JV partners under three separate permits to study storing CO_2 in areas off Australia's northwest coast to capture existing LNG emissions and grow new hydrogen value chains.

Lowering costs through technology is critical to building a profitable CCUS business. We're making strategic investments to lower the cost of capture, using our own assets to pilot new technologies. And we're studying the feasibility of transporting liquefied CO_2 to create pathways from high emission centers to storage locations.

(Slide 26): In hydrogen, we're taking early action for a high-growth, competitive business. Chevron is well-positioned to leverage our existing capabilities and assets to deliver reliable, low-cost hydrogen to existing and new customers.

We're evaluating over 50 active opportunities and are focused on developing production hubs that initially leverage existing natural gas value chains, while also enabling technology. We'll continue to take a disciplined approach, only selecting the most attractive opportunities for Chevron.

Collaboration with partners will help enable faster end-to-end solutions, acquire early-mover customers and set the foundation for future scaling of a larger hydrogen ecosystem.

(Slide 27): We're studying several hydrogen and ammonia production facility concepts across the U.S. Gulf Coast region to link our growing natural gas production base with our new CCUS resources. We're working on multiple projects across California – anchored by our Richmond refinery – to de-risk technology and support expected future demand.

In the Asia Pacific region, we're continuing our work with JERA, a long-time partner and customer, to explore co-developing lower carbon intensity fuels in Australia. We're also collaborating with partners to study the development of hydrogen and ammonia from renewable energy sources.

To summarize, we are making progress both lowering our current carbon intensity while growing new, profitable lower carbon businesses and solutions to scale.

Technology is critical to powering our business today and to realizing our future ambitions. I'll handover over to Eimear to share some of the key technologies that we're developing.

Eimear Bonner:
(Slide 28) We're focused on technology that delivers energy solutions for today and transforms the energy system of the future.

Starting with safety, in our Salt Lake City refinery, we've piloted the use of robots to inspect tanks. This keeps our people safe and out of confined spaces, and we're moving to scale the solution across our refineries.

On higher returns, we're using technology to optimize field development.

For example, we've developed a new technology to get higher-quality seismic images faster. We've used this in the Gulf of Mexico and in other challenging geological environments.

Additionally in Australia, we're testing innovative digital tools that integrate operational, reservoir, and economic data. This will enable faster field development decisions, improving cycle time from concept to production.

On lower carbon, a key focus area is methane management, as you've heard from Jeff. We're leveraging machine learning to predict and prevent emissions and we've tested advanced technologies, including satellites, to detect and make timely repairs.

(Slide 29): As we look to the future, technology solutions and innovation are critical.

In our shale and tight assets, we're utilizing subsurface technologies and advanced materials designed to increase reservoir recoveries.

To automate facilities, we're deploying monitoring systems on subsea pipelines to reduce unplanned downtime and the need for offshore interventions.

For new energies to be competitive, we must advance technology at scale and operate cost efficiently. Let me give you three examples to illustrate:

1. We're developing and growing technologies to have feedstock flexibility for renewable fuels.
2. We're piloting technologies in the San Joaquin Valley to learn how to capture carbon efficiently. To better understand CO_2 storage and reservoir dynamics, we're leveraging fiberoptics, novel seismic, and high-performance computing.
3. We're evaluating technologies to produce lower carbon intensity hydrogen. We're investing in liquid organic hydrogen carrier systems to solve one of the big challenges of hydrogen – how to store it and transport it over long distances.

We've been solving difficult energy challenges for decades, and we're working on the next generation of breakthrough technologies to deliver the energy solutions of tomorrow.

Let's move to Q&A. Please state your name and your company and limit yourself to one question and one follow-up.

Jeff Gustavson: Okay, I think Sam had his hand up first right over here.

Sam Margolin (Wolfe Research): Hello, Sam Margolin, Wolfe Research. My question is on carbon capture. I think under the Paris Accord and the UN something like 15% of GHG emissions can be addressed by carbon capture, but that's essentially like 100% of scope one and two across the industry. What we're also seeing is a lot of greenfield projects because carbon capture incentives are very robust and people are almost creating emissions just to capture them. The question is how big do you think your carbon capture business can get; how much of your initial scope 1 and 2 emissions can you address how does CCUS compare in terms of addressable market growth versus other low carbon verticals?

Jeff Gustavson: To start with, I mean [it's] a very prospective sector, I won't get into the specifics on how big this could become, but on any scenario that you look at in the world carbon capture is a part of any net zero pathway. We're talking gigatons, many gigatons, of storage for a business that today is, I believe, less than 50 million tonnes are being stored on an annual basis. We have a long way to go. This is a very large addressable market. It's a critical technology to support the energy transition for hard-to-abate sectors some in particular including our own. That gives you a sense of the size. A year and a half ago we provided some guidance on how big we think this can become in our own portfolio. We released guidance on 2030 volumes being 25 million tonnes per year both CCUS and our carbon offsets business. That's a marker that's out there. We're making good progress towards that target, but we still have obviously a long way to go, not just us, but industry-wide.

I highlight one project in particular, our Bayou Bend development in the U.S. Gulf Coast. There was a great slide on that asset. We've done a lot of work over the past year to grow our pore space, our land position. We think we have some of the best pore space in that area, almost 150,000 acres with over 1 billion tons of CO_2 storage [potential]. You're in a location with good geology, but also concentrated industrialized emissions, some of our own emissions, but also refinery, petchem, cement, and steel emissions all in that area. The customers we're talking to in that space are motivated and have net zero targets of their own, lower carbon intensity targets, and are very interested in talking with us and how they can participate in that regional hub development. And that's just one hub, so that gives you a sense of the size.

In terms of our own emissions, all of these new energies businesses, we're looking at third-party opportunities as I just mentioned with the Bayou Bend in the U.S. Gulf Coast, but we're also looking at how we can deploy these technologies to abate our own emissions.

And you might talk about in a little bit, Eimear, some of the work we're doing in the San Joaquin Valley to test technology, but also abate some of our San Joaquin Valley emissions. We're looking at large refineries around the world, we're looking at large upstream plants. We already have a large CCUS project associated with our Gorgon asset in Australia and there will be more opportunities as we go forward. Eimear, you might talk about the technology a little bit in San Joaquin Valley.

Eimear Bonner: To support all of those ambitions, both in our traditional business today and in Chevron New Energies, carbon capture is a focus for us. Particularly, we're focused in lowering the capture cost and understanding then when we do capture CO_2 how to store it safely and efficiently in reservoirs. So really two main themes, lowering capture cost and storage.

Jeff referenced some of the pilots that we've got on going. We're studying a few different capture technologies to understand which one might work best with our facilities. We've got one running in San Joaquin [Valley] today and we're doing that pilot, it's absorption-based technology with Svante. This was a company that we invested in back in 2014 and we're now testing it on one of our operating assets. We have another plan in the next few years to test another capture technology. Then we're also going to test concentrator technology, so how to integrate some of those together. We believe that the pilots that we have ongoing today, and those that we've planned in the next few years, will really help us understand that first technology objective, and that is how to capture it cost efficiently.

From a storage perspective this is an area where we're leveraging decades and decades of subsurface expertise and reservoir characterization, reservoir simulation to really model and have the analytical tools that allow us to not only look at where's the best place to store CO_2, but how to store it, how to ensure good storage efficiency in the reservoir and how to keep it in the reservoir. Those are the two technology themes that we have that support capturing carbon from the businesses that we operate today, but also in pursuit of growing CCUS as a future business.

Jeff Gustavson: That's a great combination the two of those things the internal customer base scaling technologies, and the external size of the market. You asked about which of these businesses could scale the largest or the fastest. I can't pick a favorite here. We like them all. Renewable fuels we've seen more progress sooner on the back of the REG acquisition last year, but as I talked about we're building some very large foundational projects in the CCUS space, hydrogen will follow, carbon offsets, and other emerging technologies, like geothermal will also be a part of the mix. They're all important for the for the company. Thanks for the question.

Paul Cheng (Scotiabank): Paul Cheng, Scotiabank. Two questions please. First, can you talk about how you guys view internally on the financial matrix when you make decisions on projects? How is that different than your traditional oil and gas or refining projects? I mean, clearly, given the different nature of the project that they will be different. So trying to give us a framework [for] how should we look at that from a company standpoint.

The second question is on RNG. I think the company does have operations over there in that two of your European cousins made some sizeable acquisition trying to jump start and accelerate the pace. Is that something that may be suitable for Chevron? Or you believe that your own internal opportunities or organic opportunities is sufficient for the pace? Thank you.

Jeff Gustavson: Thanks for the question, Paul. The metrics are the same. We use the same metrics to measure the economics for these investments that we use for any investments we make across the company. The returns really matter in this space. We need to be able to generate attractive returns to make these businesses sustainable. There are other drivers here. There are lower carbon, CO_2 abatement, both our own and other company drivers, but at the end of the day for these businesses to be sustainable, we have to generate returns. We want to generate higher returns and given the size of these markets, the growth of these markets, the skill sets that we bring to all of these sectors, which are critical for any net zero pathway, we feel that we can do that.

Now, the risks are greater and the bands of uncertainty are wider. I compare it to our exploration business to use an analogy. You need to understand those risks when you go into these projects. The investments also tend to be smaller, at least today versus some of the other investments we're making across our traditional business, but the same metrics apply. As we go forward, hopefully we'll be able to work on the technology lower the cost, sign up customers, have more clarity on the policy incentives that you know marry with these businesses. We'll be able to narrow those bands of uncertainty, but we use the same metrics.

Your second question was around M&A for RNG. M&A is a part of our toolkit as an enterprise and we have a good track record on M&A. We need to be very disciplined in any acquisition that we make. We're looking at organic growth in this space. We're also looking at inorganic growth, just like we do in our traditional business. We feel like we have a strong portfolio of early opportunities in this space. Anything we bring in inorganically will have to compete with some of the projects that we laid out in the in the presentation.

In the renewable fuels space, in the new energies space, the best example of where we've used M&A was the REG acquisition last year. Very happy with that acquisition. Happy with the assets and even happier with the people. We're on track with our Geismar RD expansion in Louisiana, which should come online in early 2024. EBITDA forecasts that we put out in 2025, $500 to $600 million in EBITDA by 2025 is intact. We feel comfortable with that. We're realizing synergies and we're realizing the benefit of the complementary skill sets those two companies bring together. We do have a history in this space. I won't comment on anything to a specific sector, RNG or elsewhere, but this is something that we'll continue to look at going forward. Thanks for the question.

Jason Gabelman (Cowen): Thanks, Jason Gabelman from Cowen. A couple years ago, I think you put out targets around the low energies business of $1 billion of cash flow from $10 billion of investments over eight years. Can you discuss have either of those numbers changed at all and has the makeup within those numbers changed at all? Thanks.

Jeff Gustavson: The $10 billion hasn't changed. We're sticking with that guidance $8 billion, just to remind everybody, $8 billion was directed to growing these new [lower] carbon businesses, and $2 billion will go to lowering the carbon intensity of our existing business. It'd be great Eimear if you stepped in here in a second and talked about some of the progress we're making on our marginal abatement cost curve projects. We're not changing that guidance. We'll continue to look at that. We'll look at the opportunities that come into the portfolio. We have longer queues now that we can invest in, but not all of those opportunities are investable opportunities. We'll continue to monitor that and we'll update guidance as appropriate.

No change to the $1 billion of cash flow from operations in 2030. [We] feel very confident with that. Renewable fuels is already generating cash today, and I just mentioned we expect it to generate much more cash in the next couple of years largely on the backs of the Geismar renewable diesel expansion. Projects like our Bayou Bend project in the U.S. Gulf Coast, we're working hard signing up customers to that and it has to work for both sides. We have to be able to generate attractive returns. And then a hydrogen business, doing a lot of study in the hydrogen space to drive even greater cash flows, I think next decade.

That's where we sit with the capital and where we feel confident about the cash flow from operations target.

Eimear Bonner: Maybe I'll just talk about the lowering the carbon intensity of our existing assets. Jeff mentioned the marginal abatement cost curve. This is the approach that we use, we look at all the opportunities as a portfolio. Our goal is to abate the maximum amount of carbon for every dollar that we spend. We have a large portfolio of projects, over 100 projects. We've got great momentum building around execution. Last year, we actually grew the portfolio a lot. We executed 13 projects. We'll execute three to four times the number of projects this year, So that part of $2 billion we're really putting that to work.

An example of something, just to kind of bring it to life, would be a facility project. I'll mention the one in Nigeria where on a gas turbine we upgraded the air filters. The upgrades were to mitigate fouling in the compressor section, that increased fuel efficiency and that mitigated fouling that extended duration between maintenance outages. That lowered the carbon intensity of that unit, but also maximized returns because there was that reliability benefit as well. So that's an example of one of the projects within that marginal abatement cost curve portfolio that's focused on lowering the carbon intensity of our existing business today.

Jason Gabelman (Cowen): Thanks, and my follow-up is on the inflation reduction act. You mentioned your targets are unchanged, but it would seem the inflation reduction act with support some of the economics a bit. If you could just discuss how that act has impacted the economics of what you're investing in the U.S.? And if anything in the hopper becomes more or less advantageous as a result of the IRA? Thanks.

Jeff Gustavson: We've said in the past policy support is important here. We're focused on areas where we have capabilities, where we have assets, and where we have existing customers in policy-enabled markets. That's a key part to the early stages of growing these businesses. So the IRA is a step in that direction. It's consistent with that broad policy support. There is a number of details that need to be worked through on that bill. We among many others are working through those details, but a step in the right direction.

I'll just say it's just one element where many elements need to come into place to make these businesses scale. Policy support is one of them but not just broad tax incentive or other support, local support, permitting support very important for projects like the Bayou Bend project that I noted on the U.S. Gulf Coast.

Commercial arrangements, these are new commercial arrangements between customers and suppliers. CCUS, hydrogen, and renewable fuels there's a lot of demand from customers, but at what price, how do you work through those agreements, that is going to take some time.

Finally, some of the technological examples that Eimear provided. These businesses are enabled by policy number one, but technological advancement, number two, to lower the cost to make them more viable for longer with less policy support. IRA is one step, but just one overall step hasn't changed our broader plans or strategies. Thank you.

Doug Leggate (Bank of America): Thanks, Jeff. Doug Leggate from Bank of America. Two quick ones I hope. LCFS credits have obviously collapsed quite a bit over the last couple of years. What was embedded in your billion-dollar assumption and how does that play into the trajectory to get there?

And the related follow-up: as the company broadly has talked about a 10% CAGR for free cash flow through 2027. Approximately, what do you see the contribution from the New Energies business over that period?

Jeff Gustavson: On LCFS, yes, given supply demand dynamics in California, I believe we're at five-year lows for LCFS prices. Certainly, that is an incentive that is important for the renewable fuels business. First of all, there are many incentives that make up the basket that support renewable fuels business and other businesses that we're looking at in California and elsewhere. We make longer term projections just like we do on our commodities that we sell oil and gas, we don't release those externally, but that is something we look at. We do see LCFS prices strengthening in the years to come as carbon regulations continue to tighten, but it's just one component and policy is just one component.

What's really important in running our renewable fuels businesses is we take a full value chain approach. It starts with feedstocks and being able to run diverse feedstocks in our refinery. Eimear can touch on some of the technological advancements that we're making there. It goes into running very capital-efficient assets, either existing Chevron assets or the new assets we've acquired through the REG acquisition and I mentioned the Geismar expansion is on track and on budget. Then it's accessing the right sales and distribution channels. This is where REG and Chevron really complement one another and one plus one equals much more than two. That's very important when these policies change. LCFS, we think, will spread to other geographies over time, or similar type policies. Policies change, market conditions change, and the ability to optimize across the value chain to be the lowest and the most cost-competitive producer of these products, to access new markets where market conditions may be different [is important].

Last year almost half of the product produced by REG was sold into European markets, not into California markets. All of that is really what will drive value over the long term. I don't have an answer for the cash flow question. I would say the cash flow target we put out is in 2030. It is going to take time to generate material cash flow out of these businesses more comfortable with where renewable fuels sits today largely on the back of the REG acquisition. We expect more cash flow to come from these other businesses, but I don't have a point forecast for 2027.

Eimear, you might talk about technology and renewable fuels.

Eimear Bonner: We're focused on enabling feedstock flexibility while lowering costs and maximizing yields. We think about the value chain and maybe starting with feedstocks. We have a lot of technology efforts ongoing to expand the range of feedstocks beyond the oils that we've got experience with today. We do a lot of feedstock testing in the lab. We assess feedstock, we test them, and we qualify them. We're focused on that aspect of the value chain and just expanding the set.

When it moves to kind of the manufacturing part of the value chain – the hydroprocessing, the pre-treatment – we've got a lot of technology efforts there are as well. What we're trying to do physically is design catalyst that will work at different operating conditions. Whatever gets thrown at them, they can manage, and they can manage higher temperatures and still secure the yields required. We're using our expertise in catalysis, hydroprocessing and metallurgy to really develop a solution set there. We have to care about the kit itself because of the different reactions also that go on.

Then at the other end of the value chain, and the product side are our JV efforts with Cummins and some of the OEMs we're testing these new products. We're everywhere in the value chain when it comes to technology.

What has been great with REG, bringing them into the family, is that they come with a lot of operational know how. They have expertise in feedstock procurement and supply chain. They have some pre-treatment technology and marrying that with our expertise in catalysis, hydroprocessing and metallurgy is really allowing us to learn and have faster cycle times around trying some new things.

We're co-processing today at El Segundo and we've got conversions planned this year as well. That's how we're supporting renewable fuels from both sides of the value chain and everything in between.

Neil Mehta (Goldman Sachs): Hey, Neil Mehta here with Goldman Sachs. Thanks for doing this. My question is about the capital spending in low carbon as a percentage of the business and where is it now? Where do you see it evolving over time?

And then the follow-up is just can you contrast your low carbon strategy with who your peer-set's strategy is and what do you think differentiates yours? Thank you.

Jeff Gustavson: On capital, we mentioned the guidance, the $10 billion over eight years no change to that guidance. We've spent more, invested more in the renewable fuels part of the business to start, there was a large inorganic component of that with the REG acquisition last year. We have line of sight to increase spending and to support our CCUS business and eventually our hydrogen business and that's the way you can kind of think about these. We'll continue to provide updated guidance as we go along.

In terms of percentage of the overall enterprise, I'd let maybe Mike or Pierre speak to that. We go out and we've launched these businesses, we're talking to customers. We're trying to find the very best opportunities that both abate CO_2 emissions, our own or third parties, and also generate attractive returns. We'll be opportunity-driven in terms of the overall capital spend. There is an iteration that occurs with the overall enterprise in terms of what's the appropriate amount to allocate to these businesses. For right now, very comfortable with where we sit, but we're in the earliest days. We'll see where this progresses as we as we go forward year to year.

On competitors, I'm not going to speak to another competitors' strategy. I think we feel like we have the right strategy here. We've been very careful about selecting businesses that we think are critical for net zero. They'll see significant demand growth, but most importantly we bring something of value to all of these businesses and that's very important when we look at the opportunity set. If there's not a strong strategic fit for the company in investing in a hydrogen project, a CCUS project, or building a new renewable fuels facility, then that's not something that we'll pursue. We'll be very disciplined in that.

We're asked a lot about renewable power. We're not investing in renewable power on a standalone basis, but these businesses will require enormous amounts of renewable power, so how we partner to enable that renewable power is a core part of our strategy, investing in that in a different way than some of our some of our peers.

The last thing I'd say on the on the peers is, there's certainly a competitive angle to all of this, but these markets are so large and growing so fast and so important for the company, for the industry, and for the world that partnership, with our competitors, something we do each and every day in our traditional business, is a very important part of our success going forward. We're rooting for our competitors to continue to make progress in this space because progress is absolutely what we need to make. Thank you, Neil, for the question.

Biraj Borkhataria (RBC): Hi there. It's Biraj Borkhataria, RBC. I have two questions. The first one is on hydrogen. Can you just talk to me about the economics on this space? Because there's a wide range of views out there on what role hydrogen will play. Where it's hard-to-abate or a wider rolling in different end users, but from your slides are talking about shipping ammonia from Gulf Coast and West Coast to Asia and Europe. To be frank, every time I run the numbers and something like this it's not even close to making economic sense. Can you help me understand how that can be competitive relative to other sources?

Second question is on CCS and particularly for LNG. Kind of two-part question but at Gorgon you've had some issues with not meeting your targets on CCS since startup. What makes an LNG project? What are the characteristics of an LNG project that make it suitable for CCS versus others, which are not? Just interested to know. Thank you.

Jeff Gustavson: There's a big technological angle on hydrogen, particularly transportation and storage, which is the highest cost part of the value chain, so Eimear can speak to that, and we'll get into the latest on Gorgon as well.

In order to generate attractive returns in the space, these products have to be cost competitive. The numbers have to work. We're early in that journey. There are certain sectors in the hydrogen and ammonia space that we feel will work sooner. Customers that will buy these products at the right cost; bearing that higher cost today and we're working with many of those companies in the world.

I mentioned JERA in my opening remarks. Here's a very large energy company in Japan, great company, a long-term customer from an LNG standpoint, one of our most important LNG customers. They're very interested in decarbonizing that existing LNG value chain, but looking is there a way to drop new low carbon but related products like ammonia, like hydrogen, into that value chain, at the right cost, to meet their lower carbon objectives. Those are high ambitions. They're challenging. It's hard-to-abate country. They don't have the same renewables footprint, they don't have the same tools that you might have in the U.S. or even Europe or elsewhere, so working with them on how we can produce blue ammonia using natural gas as a feedstock. We feel that's the lowest cost today. Transporting that ammonia to blend into some of their existing coal-fired power infrastructure, that's what we're trying to do.

What policy support you need to make that new value chain reality is something we're working through. We'll work the same from a European perspective, it may be hydrogen to heavy-duty transport, or hydrogen into natural gas-fired power, or hydrogen for another use. We feel with the investment in technology lowering the cost of delivering that hydrogen, with the appropriate amount of policy support to start, we'll build this new energy system really and all of the infrastructure that's needed to make this business reality. We're in the study phase now. We're doing a lot of different things: technology pilots and other things. But we'll be very cautious and making sure we marry the supply with actual demand from customers. Very prospective, but still a lot of work to do in that space. You might talk about technology before we go to Gorgon and CCUS.

Eimear Bonner: From a technology perspective in hydrogen we're focused on two things: one, lowering the cost of hydrogen production, and two, lowering the cost of hydrogen transportation. As Jeff talked about, there's carrying hydrogen and ammonia and other fluids that that carry hydrogen. That's some of the technologies that really talk to the transportation challenge there.

The way we look at this is we have tech ventures, and we make investments in companies and learn from them. This is an area where we've made a lot of investments, great investments over the last couple of years to look at some different technology solutions.

One example is with Hydrogenious and this is a company that has a liquid organic hydrogen carrier. Think about this liquid is carrying hydrogen to its destination. You've got to put the hydrogen in to the liquid and then at the customer-end you got to take the hydrogen out. We're not only studying how to put the hydrogen into the fluid but then release it at the customer-end.

The beauty of this type of technology that transports hydrogen safely in a stable form is that you can use existing infrastructure, you don't have to build new infrastructure. You can use existing ships, you can use existing pipelines. That's why we're really interested in that. And JERA, who's a great partner of ours, we're doing a pilot with JERA to test this actually in LA in California, just to see whether we can and make it viable. That's just one example in the transportation sector that we think offers promise to kind of unlock the constraint right now.

Jeff Gustavson: Great example. On Gorgon CCUS, first of all Gorgon CCUS is one of the largest, most complex CCUS projects in the world started up three years ago. It is working. We've stored 7.5 million tonnes since startup in 2019. That is less than the planned capacity. We're working very hard to reach that planned capacity. There's a lot of lessons learned throughout this process that will be very valuable as we grow the CCUS business elsewhere. Maybe Eimear can talk to some of the unique technical aspects to give a little more color on the question?

Eimear Bonner: Thanks, Jeff. On Gorgon, when it comes to capturing the carbon and injecting the carbon into the reservoir, that's working. That part of it is working. The challenges that we've had within the amount of carbon or CO_2 that we've been able to put in the reservoir, is more the water management system.

The reservoir that the CO_2 goes into, we have to take water out to create the space for that CO_2 and we've had constraints on the water side. The water that we're taking out of the reservoir has sand, it has particulates, it has to be processed and we're constrained right now as to how much we can do.

The solution is to improve the surface equipment to handle the solids and the particulates and actually to pull more water out, and once we can pull more water out, we can put more CO_2 in. The CO_2 is really working. The constraint is on the water management side.

What we have done with Gorgon is, we have 4D seismic, we have fiber optics, and data surveillance programs, we have modeled the reservoir and we feel that the CO_2 is doing what it's supposed to do.

Those learnings are the learnings that we will leverage as we look to subsequent assets where we would inject CO_2, so all of that subsurface technology expertise, all of the surveillance expertise, all of the seismic expertise, all of that will be able to leverage for growing new energy business.

Nitin Kumar (Mizuho): Nitin Kumar from Mizuho. I have two questions. One Eimear, you mentioned a technology for improved recovery in shale. I hate to bring oil and gas into a low carbon discussion, but kind of curious just one, is it primary? And two, we spent some time in the last session talking about getting Chevron back on its longer-term plan for the Permian, how much of that is being driven by this new technology and how much of it is proprietary to you? So that's my first question.

The second question, if we can unpack a little bit of that $8 billion of spending between technology and commercial opportunities. You've laid out some targets on CCUS, hydrogen, and renewable diesel. You're not getting there for $8 billion. I'm just trying to understand what does $8 billion get you from where you are today to those targets.

Eimear Bonner: I'll start with the shale & tight and thank you for asking the question because technology is critical for our existing business today to safely deliver higher returns and lower carbon.

With shale & tight, I'll just connect the previous discussion. I think some of the things that we've learned in Permian around how fractures behave, how benches interact, how much communication there can be, a lot of that was actually discovered and informed by technology. Tracer technology, tracers that we put into the frac fluids, tracers that we put into the proppant, that when produced at surface told us that we had these interactions and this interference whether horizontal or vertical, so that surveillance program, which is constant and will be adjusted as we adjust our frac designs and our well plans going forward. That's just something that's part and parcel of normal business and learning how the reservoir behaves.

The recovery project is something different and this is secondary recovery. This is leveraging our expertise and advanced oil recovery to change the dynamics in the reservoir, to change how the water and oil moves in the reservoir and how the oil interacts with the rock, and adjusting that chemistry so that we can recover more oil. That's what I referred to in my remarks and we're doing that in a number of ways. We are looking at advanced materials that we can inject into the reservoirs that will result in increased recovery. We're also looking at different stimulation techniques that we would couple with some of the chemical treatments that we're considering and we've done a hundred pilots across the shale & tight asset classes, not just in Permian we've done some as well in the Rockies business unit. We've done some as well on the Canadian business unit and all of those learnings together, is informing of you that we think we can significantly increase recoveries without drilling but actually through a different means.

That's what we're studying. We're studying it in the lab and we're studying with our partners as well.

Jeff Gustavson: It's fine to ask an oil and gas question in the lower carbon session because one of our lower carbon strategies is to lower the carbon intensity of our existing assets. The Permian is obviously getting a lot of attention, not just for that, but for other reasons as well.

Your second question, the capital guidance was consistent with the target, so those went together. It was heavier on renewable fuels on the front end. Of course, we added to that through the REG acquisition, but we're already halfway to our renewable fuels target at the end of the decade of a 100,000 barrels of bio-based diesel [production capacity per day]. We're the second largest producer in the U.S. and that's before the Geismar project comes online a year or so from now.

Carbon capture, I mentioned the Bayou Bend project, 1 billion tonnes of storage [potential]. I mean, this is a very large size potential hub, 5 to 10 million tonnes per year, maybe even more.

And the hydrogen projects, we're looking at ammonia projects. I mentioned how some of the demand could grow for ammonia in the future working with customers, like JERA. One of these facilities could be a larger size than the target that we put out, the 2030 target of 150,000 tonnes per year. We'll continue to update our capital guidance and these other targets.

We won't chase the targets at the expense of value. We're going to be disciplined here, but we feel very comfortable with the progress we've made and comfortable with the capital guidance that we've provided.

John Royall
(J.P. Morgan): John Royall from J.P. Morgan. Can you just talk about the opportunity set for sustainable aviation fuel. We've seen a couple of FIDs in that area and the changes from the IRA make that business kind of more attractive. So where does SAF sit within your opportunity set, more broadly and then maybe just on the renewable side?

Jeff Gustavson: It gets a lot of attention in the company, a big focus area. We're focused on hard-to-abate sectors. Transportation is a critical, group of those sectors. We are also looking at power and industrial customers. I've given a couple of examples of that. In heavy-duty transport we're working every aspect of it. Trucking has been the lead from a renewable diesel standpoint or a biodiesel standpoint. We're seeing increased interest from rail operators and increased interest from marine operators. Aviation is certainly the big kind of nut to crack in this space. It's more challenging, but you've got a set of customers that are in one of the hardest-to-abate sectors, very focused and motivated to talk with us and others about how we can help them lower their carbon intensity and SAF, sustainable aviation fuels, is a big part of that.

When we look at our renewable fuels business, we're looking at how we can produce more of this product, if we can do so commercially, again we need to be able to generate returns for the company. We're already producing some at El Segundo, we have the capacity to do it there. We're also looking at our Pascagoula refinery to produce more. We're even looking at the Geismar facility, the REG legacy facility, in Louisiana to determine if there are capital investments, which are more nominal capital investments, we could make to significantly grow the SAF capacity out of that asset. Policy support is important, but even more important is getting to the right commercial agreements with the customers, in this case the aviation industry. We think we'll get there, but it will take time for that to develop.

Thank you for the question.

That is the last one, appreciate everybody's interest in the company. Thank you very much for the questions. We'll now take a 10-minute break and we will be followed in this room by Pierre and Mark. Thank you very much.

Winning Combination

Pierre Breber: I'm Pierre Breber and with me today is Mark Nelson.

(Slide 30)

I'll provide a financial update, followed by Mark who will close by tying together everything you've heard today.

(Slide 31) Investing efficiently, in high-return projects, moves the needle on return on capital employed. Over time, we expect to be a solid double-digit ROCE company at mid-cycle prices.

And with our higher oil price exposure, Chevron is doing much better than that – delivering ROCE greater than 20% last year and leading the peer group in ROCE improvement over the past five years.

Capital efficient investments, combined with strong production growth, drive higher cash flows.

And with capex guidance unchanged, we expect annual free cash flow growth greater than 10% at $60 Brent.

(Slide 32) Today, we're raising our share buyback guidance to $10 to $20 billion per year. The higher range is supported by two cases shown here and reflects our greater capital efficiency and low-dividend breakeven.

As we've said consistently, we intend to buy back shares across the commodity cycle, using surplus cash on our balance sheet and excess debt capacity to continue buybacks even when oil prices cycle down.

If the Brent oil price decreases to $50 in 2025 and stays flat, Chevron is positioned to repurchase shares annually near the $10 billion end of the range.

And in an upside price scenario, with Brent increasing before settling at $70 in 2025, we could repurchase shares near the top end of the range.

Commodity prices and margins are uncertain. Our approach to returning cash is not.

We plan to repurchase shares across the cycle – acting neither pro nor counter cyclically – as we have over the past nearly two decades, buying back our shares two dollars below market and at almost half the current price.

(Slide 33) Let me wrap up by restating our financial priorities. They're simple and longstanding.

1. Grow the dividend consistently – 6% annual growth over the past 15 years.
2. Invest capital efficiently to grow both traditional and new energies as Nigel and Jeff covered in their sessions.
3. Maintain a strong balance sheet – we finished last year with the lowest net debt ratio among our peers.
4. Repurchase shares steadily – starting in the second quarter, we're raising our annual buyback rate to $17.5 billion.

As the two charts show, consistent and steady across the cycle delivers leading results. You've seen our past performance. We keep it straightforward and predictable. You know what to expect from us.

I'll now turn it over to Mark to close.

Mark Nelson: (Slide 34)

Despite the market turbulence of the last several years, our objective has remained consistent – to safely deliver higher returns and lower carbon.

We expect to generate higher returns by investing in advantaged assets, maintaining capital discipline and driving productivity improvements.

As Jeff laid out, we're focused on lowering the carbon intensity in our traditional business and continuing to grow new energies solutions.

Our straightforward and pragmatic strategy, coupled with our talented people, have enabled peer-leading results across the cycle. It's our consistent approach that generates the projects and opportunities highlighted today.

(Slide 35)

This consistency drives value.

We rank at the top of our peer group in capital efficiency and lead in total cash returned per share. We've delivered across the cycle and expect to approach the future with the same philosophy.

Our capital-efficient investments enabled the portfolio that made these superior cash returns possible. And the commitment to capital discipline is clear – we expect to profitably grow our traditional and lower carbon businesses without sacrificing gains in efficiencies, returns or free cash flow.

Our track record speaks for itself, and we intend to continue to concentrate our investments on assets and technologies that deliver higher returns and lower carbon.

(Slide 36)

To close, I'd like to reiterate our three main themes today.

1. Disciplined growth – we have confidence we will exceed our 3% production CAGR, while maintaining capital spending within our longstanding guidance.
2. Lower carbon – with a focus on the critical energy we deliver to customers and continuing to grow lower carbon energy solutions.
3. Higher cash – we're raising our share buyback guidance range and rate. We expect to have the capacity to continue to return more cash to investors in the years to come.

The future may be uncertain, but our strategy is proven – safely deliver higher returns, lower carbon. That's the winning combination.

Let's move into Q&A. Please state your name and your company and limit to one question and a follow-up.

Mark Nelson:

Let's start with Jeanine.

Jeanine Wai: (Barclays)

Hi Mark, Pierre.

Thanks so much for the time today and all the details. Nice to see you in person.

We've got two questions if we may. The first one. It really just relates to your upside downside slide, and we certainly appreciate that you're giving us a more realistic look on the price forecast that you're using in that scenario. Higher in the beginning and then the $50 [Brent] on the downside. Our first question is how different does the sources of cash look if you were to just use an even further down downside case and run $50 [Brent] through the whole case, particularly on the debt side of things?

And then our second question is really on the breakeven and can you just quantify, if possible, how that trends through the forecast period through 2027? Thank you.

Pierre Breber: Thanks, Jeanine.

Let me start with our financial priorities and I'll just restate them real quickly. The first is to grow the dividend and we've done that over the last five years more than two times our nearest peer.

The second is to invest to grow both traditional and New Energies. Our capex is up 30% [from 2022]. We've kept our capex guidance unchanged.

The third is to maintain a strong balance sheet.

And then the fourth is to return cash to shareholders in the form of a steady buyback across the cycle. We increased our [annual] buyback range to $10 to $20 billion. We increased our [annual] rate to $17.5 billion. When we do that, we're doing that with the intention of maintaining that for multiple years across the cycle.

What's going to happen over the next five years, none of us know, so we run different scenarios. You can assume our mid-cycle is in between around $60 Brent, that's flat, that's nominal, and then we have an upside case that gets ends up at $70 [Brent] and a downside case that ends up at $50 [Brent].

The sources of cash first starts with our balance sheet. At year-end we had more than $17.5 billion of cash on our balance sheet. We can run the company at $5 billion. We don't want to hold that excess cash. We're doing that just temporarily. Over time, that cash will be returned to shareholders. That's $12 billion of surplus cash. There's $30 billion of excess debt capacity. We've guided towards a net debt ratio of 20% to 25% through the cycle. We're at 3% [net debt ratio]. That's a lot of excess debt capacity.

We have a $50 [Brent] breakeven, notionally, to cover our dividend and our capex. The Brent, the oil breakeven, assumes everything else is constant. Our breakeven last year was quite a bit lower than that because we had stronger refining margins, stronger natural gas pricing. We're using the breakeven as sort of a mid-cycle on the other factors.

We're going to generate free cash flow growth of more than 10% a year from Permian, Tengiz, Gulf of Mexico, other assets, and petrochemicals. As free cash flow growth increases, our breakeven declines. Now, we're going to grow our dividend and that goes the other direction. Over time, our breakeven will go down. Now, we could run a lower case, and we have. We were the only company that showed a two-year stress test at $30 Brent in the depths of COVID-19, so we can run lots of cases. We think going towards $50 [Brent] is a reasonable downside case. In that downside case, we're buying near the low-end of the [buyback] range. We're buying $10 billion a year. $50 [Brent] is our breakeven. We're clearly doing that with the surplus cash and the excess debt capacity.

I want to be clear that there are a lot of companies that have formulas to return cash to shareholders. By definition, those are pro-cyclical. If it's 30% of cash from ops or 50% of free cash flow. Whatever it is, those [shareholder returns] were great on the way up when cash from ops and free cash flow are going up. They don't work so great on the way down.

What we're going to do is, there'll be a time our cash return to shareholders will exceed 100% of free cash flow. That's how we do it, because we're going to be taking off surplus cash and excess debt capacity. If you went to $40 [Brent], I think you know our sensitivities, it's $4 billion for each $10 change in Brent. We're happy to run lots of other cases. We think that's a very reasonable case.

The only change from the prior year is we had five [years] at $50 [Brent] and when you're sitting at $80 or $100 [Brent], it just seems like the first year or two just wasn't realistic. We try to give more realistic cases.

Neil Mehta: (Goldman Sachs)

Thank you.

One of the, I think, the hallmarks of the last couple of years for Chevron has been the focus on ROCE. A couple questions as it relates to that, you know, your confidence interval in terms of getting to the 12% [ROCE by 2027]?

And then as you think about M&A, one of the challenges, even as you were talking about Anadarko, it was M&A has a tendency to be ROCE dilutive because you mark to market the asset immediately at the point of M&A. So just how does that factor into your decision-making as it relates to those investments? Thank you.

Mark Nelson:

I'll take the front-end of that and then Pierre can close out on it.

The advantage of having a mergers and acquisition conversation in today's environment is, we don't need it. Our portfolio today, you think about the multiple growth assets that Pierre laid out of TCO, the Permian, Other Shale & Tight, and Gulf of Mexico. You think about that portfolio, we do not need additions. That's exactly when you want to naturally be looking. Think about the actions that we have taken in the market, whether it's REG or the Noble acquisition, and we were able to do those at a time and in a structure that made sense for us and was useful for our shareholders.

We'll continue to take that logic going forward. It's nice to be looking when you don't have to be buying and we'll continue to take advantage of that today. The point I would reinforce is that we don't need it and that we look at actions that are value driven in this space.

Pierre Breber:

We don't have bright-lines on accretion. Noble was accretive on all, which is fantastic. That's what you seek out. Anadarko, you're right. We'll look for sure at earnings accretion. We'll look at cash flow accretion or free cash flow accretion. ROCE accretion is a nice thing to do, but it wouldn't stop us from doing a transaction. Again, there's no bright-lines on that. We'll look at the totality of the quality of the assets, the strategic fit. Of course, there's got to be something in it for our shareholders, the do-ability. We'll look at a variety of metrics. And your absolutely right. That's one of the toughest ones, but we've shown we can do that, too.

Mark Nelson:

Doug.

Doug Leggate: (Bank of America)

Thanks, gentlemen. Doug Leggate, from Bank of America.

Cash capex, Pierre. I wonder, I know it's a favorite topic that you've periodically given us guidance on, so as Tengiz rolls off, I think Mike had alluded to maybe another billion dollars available for capital. Can you just walk us through what the moving parts are in the cash capex? And I've got a follow-up, please.

Pierre Breber:

Our current budget on capex, we've changed our nomenclature to capex and affiliate capex, which conforms with how others do it. And so the consolidated company capex is $14 billion. Our guidance is $13 to $15 billion. There's a billion [dollars] of range to move up as our affiliate capex goes from $3 to $2 billion [in 2024-2027]. We're still within the $17 billion [annual guidance] combined number that we've been talking about. That [additional] billion [dollars] is largely more activity. It's more activity in the Permian, it's more activity in shale & tight, and there's some other puts and takes.

We'll announce our annual capex budget, you know in December for the next year. This year, we're at $14 billion. There's no change in that. We affirm[ed] that long-term guidance and there's a billion [dollars] of space to still go in. It could be absorbed by some inflation. But right now the plans are that it's primarily increased activity in Permian and Other Shale & Tight.

Mark Nelson: If I could add on that. The piece that I would reinforce is, what that capital discipline on this portfolio has delivered over the last five years. I mean you look at how we beat our competition on cash returns [per share] to shareholders. You look at the leading capital efficiency and return on capital employed performance. That's the combination of this capital discipline and the portfolio together.

Yes, follow-up?

Doug Leggate: (Bank of America) Yeah, my follow-up, and it's kind of bit of a self-serving question, so I apologize.

Mike also alluded to, or mentioned, the possibility of significant expansion on your LNG portfolio towards the end of the decade. And I noticed you're using in your assumptions $4.50 average Henry Hub gas prices, which is apart from 2022, I don't think we've seen that in quite a long time. So, when you think about the big picture, LNG growth, LNG expansion, $4.50 [average Henry Hub] gas [prices], and you look at the valuations of some of the U.S. gas equities, how do you think about your portfolio ability to leverage that LNG opportunity? I guess it's an M&A question.

Mark Nelson: Yes, I think I'll address the context that Mike was creating first and you can tag on here, Pierre.

Our gas portfolio is Pacific Basin leveraged and Pacific Basin focused. That's with our associated gas out of the United States and our strong position in Australia. We've begun to increase our exposure to Europe, but the structure is to be Pacific Basin weighted and have growing exposure to Europe. We've taken actions, clearly, we've got our U.S. Gulf Coast offtakes that'll come towards a latter part of the decade. We have a strong West Africa position that we're keeping full and effective. And of course, we have our Eastern Mediterranean piece, which I think is what Mike was alluding to in regard to the Leviathan asset in and of itself and making decisions about what we do with that very large gas, offshore, low-carbon resource. And that decision, although likely made from a design standpoint this year, that wouldn't come to market until later in the [decade]. But our portfolio will continue to be Pacific Basin weighted.

Gas prices in the U.S. obviously have come down quite a bit. But we like our portfolio today.

Pierre Breber: Yeah, just to address [the $4.50 Henry Hub gas price assumption]. I mean it's a 2027 assumption. So, we'll see. It's been a very warm winter and obviously price oversupplied. One thing we've said is no structural change in oil, right? $60 [Brent] is our mid-cycle 2027 assumption. No structural change in refined products. We have said with the war in Ukraine and the EU reducing Russian supplies, those molecules aren't finding their way into the market. There's going to be more LNG exports. We position ourselves with offtake agreements, but that'll be a pull on Henry Hub prices. It's a modest increase from where we were prior year. It reflects what we think is going to be likely in five years, a little tighter pull on Henry Hub and really mostly for exports to European markets.

Mark Nelson: Yeah. Long-term we believe in Asia strength.

Biraj Borkhataria: (RBC)	Hi there. Thanks for taking my questions. Biraj Borkhataria, RBC. So, two questions. The first ones on a small change to the deck. Last year, you talked about 10% CFFO CAGR. This year is free cash flow which makes life a little bit more tricky. But could you just help me understand if there's any, you know, changes? I know affiliate capex has moved down, so that flatters the free cash. Just a bit of color around that would be helpful. And then secondly, on the dividend. If I'm thinking about, you know, 3% production CAGR with margin accretion, which is what you point to, plus buying back your 3% to 6% share capital each year, that kind of points me to the dividend growth rate over the medium-term rate 10%, per annum. Obviously subject to price. I'm not expecting guidance, but am I thinking about those moving parts the right way and the buyback linking to DPS growth?
Pierre Breber:	Sorry, what was the number you said? It led you to what number?
Biraj Borkhataria: (RBC)	10%.
Pierre Breber:	On free cash flow versus cash from ops, I wouldn't read a lot into [it]. We've gone back and forth a little bit. It's how the numbers shake out. I think we're going to stick with free cash flow. I mean [you said] it makes your life more complicated, but I think it's most meaningful to investors because it's what's available to investors after we go through it. We've done it per share. Now, we just decided to do on absolute free cash flow and then obviously the share count is decreasing significantly in these scenarios with the buybacks. Let me take the tip and then you can add, Mark, to either one of these. You got 3% production growth. We've talked about reducing opex per barrel 10% by 2026 at mid-cycle conditions. You've got margin expansions, you've got the shift in how we're investing our capital. We are a much more efficient capital investment. That's where you get the 10% free cash flow growth. That's what is our ability to grow the dividend, clearly, and do it in a sustainable basis. Now some of that is TCO, right, coming back after a number of years of investment. When we think about dividend increases, we're thinking about an increase in perpetuity. We have to have confidence that we're going to be able to, just like we have, grown [the dividend] for 36 years, not cut [the dividend] since the [Great] Depression. When we think about share buybacks, we're thinking about over the cycle. We got this question on the fourth quarter [2022] call. We're not trying to manage an absolute dividend burden. We're also not trying to manage a share count. The buyback is a way to return cash to shareholders over a cycle that's excess to the first three priorities. The dividend is returning cash forever. That's how we view it and they're just operating on different timelines, but you're right if you put all the accretion from the buybacks, and the free cash flow, and TCO coming on, you can get to higher numbers. That's a decision for our Board. We stand by our track record: 36 years of growing dividends, 6% [dividend growth] CAGR over the past 15 years, five-year dividend growth [per share] twice our nearest peer, and we're doing that, in addition to, significant buybacks.
Mark Nelson:	Over here, Sam.

Sam Margolin: (Wolfe Research)

Hi, Sam Margolin, Wolfe Research.

Inflation is a hot topic and it is particularly important to your program because everything kind of fits together like a puzzle, right? And inflation can really be a grenade in that. So the question is tying back to the margin expansion slide from the first panel [slide 8] and then the free cash flow growth targets. You know, a lot of that's driven by mix shift, in shale, Gulf of Mexico, higher margin than some of these conventional barrels that are rolling off. And so the question is, you know, is there any tension or friction? Is there an inflation point where some of the mix shift gets threatened? You know, where it changes, it's cheaper to stem decline in conventional than it is to start new projects. And so the question is there any inflation risk to the margin expansion targets on the basis of projects, you know, moving out of the stack?

Mark Nelson:

Yeah, thanks Sam. If you if you step back, let's talk about what's been built into our plan first so you have that foundation. Inflation is always an opportunity for us. Today we have built inflation into our 2023 capital [guidance] at that 5% to 7% range for the entire portfolio and low double-digits for the Permian. That's built into our capital plan today, recognizing that because we have such a portfolio in the Permian, we're able to go out and get our contracts for wells and services and things like that not just through 2023, but well into 2024.

We feel comfortable with the current balance today. The mix we have from a portfolio standpoint is completely intentional. The returns in the Permian are so competitive that your premise that it's easier to do base decline, which is only 2% in our current portfolio, I might challenge that a little bit. I mean these shale & tight resources are very competitive. Our ability to stay within our capital forecast, while increasing activity, is built into the current plan, but it is something we'll have to watch. If inflation continues, it's something that we can test over time.

Pierre Breber:

The best proof-point, the Permian had the highest inflation last year in the industry. Jay Johnson showed this on the second quarter [2022 call]. You'll see it in our proxy coming out. Our cost to develop for EUR, expected ultimate recovery, stayed at $8 a barrel last year, which is the same as it was in 2021 in a different inflation environment.

I'm not saying we can do that every single year. There's how we procure for goods and services, and we think we do that better than others. There's what we do with those goods and services, how efficient are we with them. And then we're working really hard to offset it.

But yes, if we see sustained high inflation rates, which we are already seeing some things moderate at this point in time. And I'd also say I don't think there's a structural change in the service company industry. We are seeing it's near capacity, right. Rigs are near capacity, sands are near capacity, lots of things. You'd expect prices and margins to reflect that. We can add a rig that's not currently in service by refurbishing, paying for that, and doing a little longer-term contract. In our fleet, that's a very manageable thing to do. I think we have a lot of tools to manage inflation. But if we saw sustained high inflation, then of course that at some point time, we could revise our capex guidance.

Mark Nelson:

I don't know if you had a chance to ask Eimear this question, but the application of technology in the business continues to provide dividends. From my perspective, learning a bit more about what we can do with new frac fluid or fiber optics in the shale & tight in and of itself, creating significantly more recovery on the current activity we're doing today. Those are things that we will continue to lean forward on that when you [look] on a unit basis, we may be able to offset the pressures that we're experiencing.

Nitin Kumar: (Mizuho)

Hi, Nitin Kumar from Mizuho.

I want to pick up on that last point you just said. So this technology that improves your recovery. Let's for assumptions sake you have 50% better recovery for 10% more capex. What do you do in that scenario? Do you keep your activity levels the same or do you grow faster?

Mark Nelson:

Well, from our standpoint, remember, what's the returns based decision? Production for us is an outcome and always has been an outcome. With that in mind, you've seen 3% [production] CAGR that we have considerable confidence in our ability to deliver that.

Today, we would say we don't need to grow faster. We just need to continue to get the highest returns to the business. I think we would, today, we would stay within our capital guidance and continue to get more efficient.

Pierre Breber:

The objective is to grow the company with the least amount of capital. We are not a growth investment. We attract dividend PMs, value investors, increasingly some, growth at a reasonable price.

Our 3% [production] growth, you can do the math. We're showing more than that. We want to have high confidence in our ability to deliver on it. If we can deliver these business results with less capital, that's what we're going to do. We're much more capital efficient than we were. We've seen the other movie, that was 10 years ago, where we maximize capital and didn't grow even at these rates when all was said and done. And we lost investors. We're working hard to win investors back to energy. We made some progress last year. We still have a long way to go.

It's this consistent quarter-in, quarter-out, showing capital discipline, working hard to have efficiency that offsets inflation, using technology to improve returns. And if we can grow 3% [production CAGR], find margin expansion a couple other percent here and there, and have reasonable prices, you can see that we're a very attractive investment. There's a lot of upside left where you know, we're 5% of the S&P 500 by market cap, we're 10% by earnings and cash flow. We still have a lot of upside with investors, but we've got to show it quarter-in, quarter-out and grow at reasonable rates, and do it with the least amount of capital.

And that's the mindset shift that you've seen. There's a portfolio shift, but there's really a mindset shift. Our engineers are how do we get this project done with less capital? Because if not, they're not going to get the capital.

The bar is set really high. The Permian sets the high bar, Other Shale & Tight, even how we're doing Gulf of Mexico is very different. We used to do sort of custom designs and size it to maximize initial productions. Now their sized in the standard way, a longer plateau.

There's a lot of actions that we're taking to improve capital efficiency. It's all about winning investors back to energy. It's their capital. We need to be really wise with it and we are.

Mark Nelson:

A follow-up or are you good?

Nitin Kumar: (Mizuho)

Sure.

So, Mike said in an earlier question that he thinks we're at the highs of a commodity cycle right now. Today, you're leaning into your buyback where you just said you want to be counter-cyclical, not pro-cyclical. So, could you sum that up for us? What is your – I won't hold Mike's comment against you – but if you want to talk about your macro view and then the decision to lean into the share buyback pace, starting in the second quarter?

Pierre Breber: Well, let me start and Mark can add.

The buyback guidance is a sign of confidence in the company's ability to generate surplus cash to those first three [financial] priorities. And it's because we're more capital efficient. It does reflect what looks like more of an upside case over the next several years, but we have the range and we intend to use it. But again, we're not trying to be counter-cyclical. We're trying to be across the cycle and we're trying not to be pro-cyclical. I think most of the various cash returns to shareholders are pro-cyclical – variable royalty, special dividends. It all works great in the up-cycle. What do investors get in the down-cycle? What would investors get in the down-cycle with Chevron is, of course, the dividend, that will continue to grow, right? It grew through COVID-19 and you'll get that steady buyback even in those out[er] years. We're setting it at a level that we can maintain it across a number of years.

Commodity prices and margins are going to bounce up and down and we're just going to set a level that we have confidence that we can maintain it for multiple years.

Mark Nelson: Yeah and I want to build on the confidence in that 10% free cash flow growth that we talked about earlier. The growth assets that we have today, it's the Gulf of Mexico, it's the Permian, it's TCO, it's Other Shale & Tight. It will be the petrochemical crackers that come on in the second half of the decade. Those are multiple assets that will drive cash, including our renewable fuels business. I mean, these are all things that are incremental to conversations over the last couple of years that just give us high confidence in that.

Pierre Breber: And just to put a point on it, that's all at $60 [Brent], right, so that free cash flow growth obviously at $70 [Brent] is even higher.

Mark Nelson: Up here in front, Paul.

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

Two questions, please. I have to apologize. I want to go back into the buyback. I think in your high and low case, really the distinction is by 2025 and forward whether you see $70 dollar [Brent] plus or that you see $50 [Brent], right? So between now and then what may trigger the change in your buyback pace from currently $17.5 [billion] to higher into $20 [billion] or lower back to $15 [billion] or maybe below. What maybe the trigger upon?

Pierre Breber: Well, I'll start and you jump in.

I mean, look, it's an uncertain world. We know China's reopening. We don't know exactly how that's going to show up. We have the central banks tightening interest rates. We had a strong PCE [personal consumption expenditure] number on Friday, running hotter than people expected. We could have a hard landing, we could have a soft landing. It's a cyclical business, Paul, you know that. We've been in it a long time. Prices go up and down.

There are a lot of factors that could drive it and so we're just doing our best gauge of what we see the next several years going and we're setting at that level. We're keeping the range. We reserve the right to change it. We worked our way up to this level as we got greater confidence in what we think is a sustained recovery. The supply side is in there and what we see on the supply side. It's all the factors that you normally track, but they're uncertain. And the future is uncertain, so we have a range of scenarios, and we have a range on the buyback. But again, we could have a much bigger buyback right now, but that would be pro-cyclical. We're sitting at a level with the best of our knowledge, that we have of an uncertain future, of how we can maintain it steadily, or keep it steady, across the cycle.

Mark Nelson: Yeah, I would just reinforce the uncertainties. If I had to pick the biggest uncertainties today, we were talking about this earlier this morning. The idea of China's reopening, whether that's a straight line in regard to energy demand or a bit more up and down as they get through opening from post pandemic. When you think of the resolute approach of OPEC today, and the E&Ps and their capital discipline, that keeps supply in a fairly steady space today. And then you have the uncertainty of Russia and the economy that Pierre mentioned.

In a year of what I would consider uncertainty, the one thing that is certain is our ability to deliver on the four financial priorities.

Paul Cheng: (Scotiabank) Thank you.

The second question, maybe. Want to talk about as a gatekeeper how you decide whether the project will be [an] acceptable return and then you will go ahead. For example, I mean, Tengiz, because the characteristic that the free cash flow, once that they come on stream, is big and is really very long duration, that you can last that. So I think at the time when you're sensing the project you accept a lower return. I mean even without the cost overrun, that the return will be low.

So if I look at the new business venture, based on the characteristics and also that to some degree that you are earning your social license, how [will] those return criteria be different than your traditional oil and gas business? I mean, are you willing to accept a lower return and if you do, what is the minimum that you need in order for you to say, "Yes, you get the go ahead and be able to proceed with those". Thank you.

Mark Nelson: Thank you, Paul.

If you if you think back to our Energy Transition Spotlight, we made it very clear our expectation was that our new energy businesses would compete on return on capital employed and returns themselves. And so you step back, and you think okay, these are emerging businesses. What does that look like in the short-term? When we make our capital allocation decisions today, it's a mix of our strategy and then a portfolio return basis. For the strategies of each parts of our business, we have expectations of what they need to be funded to grow and to sustain and then we do it on a returns basis of that mix. Your comment about making investments in things that will be longer standing, meaning they take larger projects, we will still have to make those decisions as a corporation.

But from a renewable fuels standpoint, let's talk about the New Energies businesses that are available today. The returns in the renewable fuels business are competitive today. And that's the part of the portfolio that of course started to grow in New Energies sooner. Today, we're the second largest bio-based diesel supplier and marketer in the United States and one of the largest in the world. That's in addition to our activity that we did with the Bunge joint venture and our recent acquisition of the remaining shares of Beyond6, in the compressed natural gas space. All of those returns compete, predominantly, because the customer can use it today in what they have. And so it makes sense that that would come first in the evolution of our New Energies businesses.

When you're building a CCUS business, you want to start more thoughtfully, because there's an issue of building an entire value chain that's necessary. Today the place that you would expect us to start, and I suspect that Jeff talked about this earlier, the first place you'd go is acquiring pore space in a place where you think you will need it over time. We are doing a very good job of that today.

On the hydrogen side of the equation, you're likely going to follow the natural gas value chain, but you're going to be very careful until you can figure out how to transport gas and make it economic. And that's why you're seeing those more back-end loaded.

But we are well on pace to our $1 billion of cash flow from operations for our New Energies business driven by the part that can deliver those returns today, which is renewable fuels.

Pierre Breber: Yeah. I'll just go to the traditional business, and we've always had more projects in the Upstream than we would fund. You're trying to fund, obviously, well above the cost of capital. But I'd say [with my] 30 plus years in the company, that spread is higher than it's ever been and the only way to get return on capital employed up to 12% at $60 [Brent by 2027]. Now, we were above that last year. But now if you're at $60 [Brent], is by investing in projects well above your cost of capital. We have those and that creates more competition for engineers to get the returns up, which means you got to use less capital. This is all about, again, how you invest less capital to achieve your business objective. And I think we're just seeing it's a mindset change. And look it was forced on us in some ways by the market when you're an underperforming sector for 10 years. You got to change the game. You got to change the outcome. We have changed it and I think it's underappreciated how much more capital efficient we are. We can sustain and grow this enterprise at $14 billion capex, at rates higher than we could grow when we were doing twice that capex, and that's what we have to get and connect with investors. These are different companies. We're a different company. It's a different portfolio. You can see our results quarterly because a lot of it is short-cycle. I think as you see quarter-in, quarter-out, that it takes this amount of capital to grow cash flows. I think we'll get more investors back to energy.

Paul Cheng: (Scotiabank) *[Inaudible follow-up question]*

Pierre Breber: You should not assume that. It's a function of, Permian's 30% [ROCE]. As you know, we're managing a portfolio of businesses. We talked about inorganic, which will have different characteristics. But you should assume that we're going to get the 12% [ROCE] at $60 [Brent by 2027] and we'll find lots of ways to do that. Thanks Paul.

Mark Nelson: Okay, over here in the back.

Lucas Herrmann: (Exane BNP) Thanks Mark. Thanks Pierre. It's Lucas Herrmann at Exane BNP.

Sorry, this is probably detailed rather than structural and framework. Two, if I might. The first is just Australia, PRRT [petroleum resource rent tax]. Are you there yet? Are you paying you know, PRRT, etc.?

And the second was just what the tax position around TCO is, as well going forward. Clearly, you've been investing very heavily. I would presume there's been a benefit of allowances as a consequence in terms of the, you know, cash generated and effectively returned to you. Again it's the question on taxation, etc. in that region. That's it. Thank you.

Pierre Breber: Thanks, Lucas. We did a full tax transparency report in Australia. I encourage you to review it. It's part of the stakeholder engagement. We are, I believe, I'm not 100% sure, I believe we're not yet paying PRRT, but we will one day. It depends on future prices as you'd expect, but there's full tax transparency in Australia. PRRT is essentially like a windfall profit tax or it's when your returns get to a certain level, you pay additional taxes. It's built into the tax code, it's of interest to stakeholders and we're sharing a full transparency on that.

On Tengiz, it's an affiliate. It's going to have its consolidated tax return in Kazakhstan. You're right that there were some tax benefits that were accruing as we were constructing it. And again, there's the 15% withholding tax, which is what you really see when we receive the dividend. So the tax benefits are kind of part of the cash flow within Tengiz, which is a separate company. And then again, what we receive as a shareholder is the dividend and we've shown that we expect that free cash flow to grow, you know to $5 billion at $60 Brent and that'll come back. Some of that. That's our share that'll come back to Chevron in the form of higher dividends and debt repayment. We have about $4.5 billion of debt that will be repaid over that time and that'll be a different part of the cash flow statement.

Lucas Herrmann: (Exane BNP)

And sorry, just following up on the PRRT point.

You've got an assumption on price. You've got an assumption on volume. You've got assumption on cash flow in terms of Australia. So, at what point do you actually start paying?

Pierre Breber:

That's not something I'm going to disclose, because those are all uncertain and it's going to be when all those things play out and there's a very rigorous, you know, approach of the tax authorities and it's based on the actual return. It's not something that it's even worth speculating about it. It'll happen when it happens, at that point time of and it'll kick in.

Thanks Lucas.

Mark Nelson:

Keep on coming this way. Thank you.

Jason Gabelman: (Cowen Research)

Thanks. Jason Gabelman from Cowen.

Two quick ones on the financial outlook. Just going back to Biraj's question and trying to tie last year's guidance to this one to be clear. Was there any change to your cash flow from ops outlook because it does seem like it's a touch lower? I think if you do the math, our math at least, it was $32 billion of CFFO in 2026. Is that the, I don't know if that number is right, but in terms of your outlook, has it changed at all?

And then secondly on capex, I know it's a tight range $15 billion to $17 billion, but based on the environment we're in today, thinking about inflation potentially staying high. Is it fair to assume the capex [guidance] continues to come in at the high-end of the range over the planned period? Thanks.

Pierre Breber:

On the second question. Yes, you should assume that we're trending towards the high-end in the range. Look, it's a good part of the cycle. The bottom-end of the range, which we went actually below [capex guidance], reflected a tougher time in the scenario in the cycle.

So yeah, you should expect, as I said to the earlier question, more activity in the Permian more activity in Other Shale & Tight. You should see us trend towards the high-end of the range. And as you said we have inflation.

I think I'll take your detailed cash from ops question offline and work with Roderick. We are not trying to move anything around. We are doing free cash flow. It's very simple. The free cash flow growth comes from Tengiz, Permian, Gulf of Mexico, some petrochemicals, Geismar expansion. I think it's pretty transparent. We have some assumptions that we put in there. Some are higher, right, our gas price we talked about that is higher. International LNG prices are higher. There's some puts and takes in that, but I think we can reconcile all that, probably offline.

John Royall: (J.P. Morgan)

Hi, John Royall from J.P. Morgan.

So just thinking about your dividend growth versus your free cash flow growth. Assuming you stay with a 6% or so pace on the dividend growth. You're growing free cash flow by 10% [by 2027], you throw in reducing share count with the buybacks. So dividends, you know, in total dollars would be less than 6% growth. So is that a case for potentially accelerating the pace of dividend growth? And I realize it's a Board decision, but you know conceptually it would seem that it was 10% structural free cash flow growth at a flat price, you could probably accelerate there more on a sustainable basis. So just the pacing of the dividend relative to free cash flow growth, and I guess it gets into dividend versus buyback?

Mark Nelson:

Well first, let's go back to I think, Paul, was your question about uncertainties. If you can help us confirm China's recovery and demand and then what will happen with Russia in Ukraine, and then interest rates and recession might be easier to answer the question.

But the reality is we're designing to do this through the cycles.

Pierre Breber:

We intend to have leading dividend growth and we've had leading dividend growth. For five years, we've been twice our nearest peer. That means there are three other peers who are even further from us and I think we know what a lot in the industry did. We protected the dividend. We showed the two-year stress test at $30 [Brent]. Our investors knew their dividend was safe. We increased it actually, 8% right before COVID-19, 4% through COVID-19, and then 6% earlier this year.

We have to look at a lot of measures, our free cash flow growth is absolutely part of it. Now some of that is tied to TCO and the high investment levels that we've done. We have to factor all that in we have to make a recommendation to the Board, but I want to be very clear, we intend to lead in dividend growth and we have. We want to keep all of our portfolio managers who are focused on the dividend very happy. And then the other hand, we're trying to attract growth investors and value investors and others and so we really have a balanced approach. We've got to look at our competitors, other uses of cash, and everything that you'd factor into it. Free cash flow is a good indicator of our confidence in continuing to lead in dividend growth.

I wouldn't try to infer you know any specific number and it's really not a decision for us. It's a decision for our Board, as you say.

John Royall: (J.P. Morgan)

Good. Thank you.

And then second question is maybe more housekeeping and if it's too detailed happy to take it offline. When you talk about the breakevens being quite a bit lower than $50 [Brent] per barrel in 2022, just to confirm, you're only flexing the oil price there and the downstream margins are staying the same? Because looking at slide 31 when you normalize everything, it looks like $10 billion of free cash flow is actually below the dividend at $60 [Brent]. So when you talk about the $50 [Brent] notional kind of what are the downstream so assumptions there?

Pierre Breber:

What I meant, to make sure it's understood, is that you use actual margins in 2022 and actual gas prices. It's an oil breakeven, so you're calculating for the oil price, but you're letting everything flow. Our actual 2022 breakeven was well below $50 [Brent]. Now, if we normalize 2022, which I think is what you're doing in the math, and you go to mid-cycle prices for natural gas, mid-cycle margins for downstream, obviously then you're going to be closer to that $50 [Brent] and it bounces around. We use $50 [Brent] as a notional number and we can take you through all the numbers. But I was referring to our actual 2022 breakeven. Oil breakeven was much lower because other parts of the business were above mid-cycle.

Ryan Todd: (Piper Sandler)	Thanks. Ryan Todd at Piper Sandler. A question on the downstream investment at Pasadena. The expansion that you have going on there. Is that a, you know, is that more of a function of coordinating with your Permian growth outlook that you have there, or does that infer a certain view on the downstream margin environment going forward?
Mark Nelson:	Well, I think all the way back. I think we might be the only company to have purchased a refinery in the not too distant past, but the logic in the acquisition itself was to really serve three value chains. One was two refineries together in the U.S. Gulf Coast, Pascagoula and the Pasadena refinery, because you can trade intermediates and schedule turnarounds and things like that. We also had the ability to place our own product in those markets which we were serving today. So, putting our own refined product into the local markets, rather than trading for them if you will. And in the third, perhaps most important, was the ability to place our Permian production into that particular facility. The investment, is a relatively small investment, but the investment in Pasadena, is so that we can put more of our Permian production through that particular facility, taking it up to [125,000] barrels a day. It will be a good return project.
Pierre Breber:	It was always envisioned as part of the transaction. When we acquired Pasadena, it was with the intent down the road to do this modest investment to have it fit the Permian.
Mark Nelson:	We wanted to operate it long enough to make sure we knew how to do the investment with confidence. That’s what we’ve done. Thank you. Over here, and then we’ll come up front with Paul.
Devin McDermott: (Morgan Stanley)	Hey, Devin McDermott with Morgan Stanley. I have a quick one. Pierre, you mentioned 10% opex reduction over the forecast period and you all have been, I think very good versus peers in being ahead of the curve and cutting costs out of the business, driving efficiencies. Can you talk a little bit more about what’s driving that – is that mix shift across the assets or they’re more cost cutting and efficiency opportunities that you have in the plan?
Pierre Breber:	Yes, some of it is mix shift, some of its growing barrels in areas where we already operate. We’re going to have more barrels in the Permian, more barrels in Tengiz, even Gulf of Mexico. We transformed our organization, you know different ways of working, digital. I mean all of that. Now it’s sort of a mid-cycle, because you have transportation, you won’t see that so much in 2022. But as we look out to 2026, we stand by that [opex] guidance and we’re working hard towards that [opex] guidance.
Mark Nelson:	Paul, yes.
Paul Sankey: (Sankey Research)	Yeah, hi sorry, a quick detail question. But are you guiding to [asset] disposals still?
Pierre Breber:	The guidance for this year is up to $1 billion. The only assets in the public domain are interest in Alaska and Myanmar, which we’ve talked about previously.

Mark Nelson:	We've historically averaged about $2 billion a year. We'll continue to high-grade the portfolio over time, but as Pierre said, it's under a billion for this calendar year. Up here, up front.
Doug Leggate: (Bank of America)	Thanks guys, apologize for the follow-up. I just wanted to check a little bit of math. So, the 10% CAGR, just eyeballing the charts, actually looks more closer to 15% CAGR. Is that right?
Pierre Breber:	It's higher than 10% [CAGR], it's greater than 10% [CAGR].
Doug Leggate: (Bank of America)	Okay on cash flow then, that's about a 5% CAGR, or is that right? On 2027 goes to $37 [billion].
Pierre Breber:	Yeah, it's about $10 billion of free cash flow, absolute free cash flow growth.
Doug Leggate: (Bank of America)	So 15% CAGR free cash flow.
Pierre Breber:	We like to keep a little something. We like to give guidance that we deliver on and so we show you, kind of the numbers, same thing on production, but we're going to focus on 10% [average annual free cash flow growth] because things happen. But yeah, you can look at the math and it's higher than [that], it's about $10 billion. You can get $4 billion from TCO, you get $3 billion from Permian, you get $1.5 to $2 billion from Gulf of Mexico, Geismar, petchem, you add it up. It's pretty straightforward. Self-helps in there, too.
Mark Nelson:	Hence the confidence.
Doug Leggate: (Bank of America)	The reason I asked for the clarification is the dividend question, right? So it looks like the cash flow growth then is about 5% CAGR. How do you think about dividend coverage as we think, try and gauge what your dividend growth could look like, in absolute terms? Thanks.
Pierre Breber:	When we engage with our Board to John's earlier question, we look at a variety of measures. What I can say and then Mark can add to this. We're a better company than we've ever been. We look at the 2000s was when we were winning investors. And if you look at our capex efficiency, so we look at capex to cash from ops. We look across a number of metrics. It really looks like the early 2000s. It looks like the time period when we went from 5% of the S&P 500 to 10% when we were still capital and cost disciplined before the industry started investing further. All those metrics are very favorable. If you looked at them, I think this is John's question, you could argue your way to higher dividend growth. Those are the kinds of discussions that we have internally. We need to have confidence in the sustainability of it. Again, a dividend increase is in perpetuity. The share buybacks, which by the way are record high rates, also reflects confidence across the cycle. Both reflect a lot of confidence. As we get more and more confidence that we can sustain those dividend increases in perpetuity, then you're right. You're seeing a portfolio that has the capacity to do more. We also have to look at the competitiveness. What are others doing? There's a lot of factors that go into it, but the takeaway is we're much better company than we have been and we have a lot of confidence in our ability to deliver on our guidance.

Mark Nelson: I would just build on the confidence theme. When you have the portfolio that has multiple growth assets that we have and this leading capital efficiency, those things together allow us to continue to be this far ahead of our competition on these key financial metrics. And you can see that in the numbers that we've presented.

I wanted to say thank you. It is fantastic to see you all in person and for, as usual, the thoughtful questions. Certainly appreciate your interest in Chevron and just want to say thank you again.

We will continue engaging as we always do to get more feedback and continue to drive the company to a better place. But thank you again for joining us. It's great to be with you all.