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P: Operator;;
C: Eldar Sætre;Equinor ASA;President & CEO
C: Lars Christian Bacher;Equinor ASA;Executive VP & CFO
C: Ørjan Kvelvane;Equinor ASA;SVP of Accounting
C: Peter Hutton;Equinor ASA;SVP of IR
C: Svein Skeie;Equinor ASA;SVP for Performance Management and Analysis
C: Unidentified Company Representative;;
P: Alastair R Syme;Citigroup Inc, Research Division;MD and Global Head of Oil and Gas Research
P: Alwyn Thomas;Exane BNP Paribas, Research Division;Analyst of Oil and Gas
P: Anders Torgrim Holte;Kepler Cheuvreux, Research Division;Equity Research Analyst
P: Biraj Borkhataria;RBC Capital Markets, LLC, Research Division;Analyst
P: Christopher Kuplent;BofA Merrill Lynch, Research Division;Head of European Energy Equity Research
P: Christyan Fawzi Malek;JP Morgan Chase & Co, Research Division;MD and Head of the EMEA Oil & Gas Equity Research
P: Jason Gammel;Jefferies LLC, Research Division;MD & Senior Equity Research Analyst
P: Lydia Rose Emma Rainforth;Barclays Bank PLC, Research Division;Director & Equity Analyst
P: Martijn Rats;Morgan Stanley, Research Division;MD and Head of Oil Research
P: Oswald C. Clint;Sanford C. Bernstein & Co., LLC., Research Division;Senior Research Analyst
P: Peter James Low;Redburn (Europe) Limited, Research Division;Research Analyst
P: Thomas Yoichi Adolff;Crédit Suisse AG, Research Division;Head of European Oil & Gas Equity Research and Director
P: Halvor Strand Nygaard; Analyst,SEB

P: Yoann Charenton;Societe Generale Cross Asset Research;Equity Analyst

+++ presentation

Peter Hutton^ Good morning, ladies and gentlemen, and welcome to the Equinor Third Quarter Analyst Call. We will start, as usual, with a presentation from Lars Christian Bacher, our Chief Financial Officer, and then we will open up for questions. (Operator Instructions) And with me on the call today, I'm joined by Svein Skeie, who's Head of Performance Management; Ørjan Kvelvane, Head of Accounting; and Russell Alton, Head of Finance.

And with that, I'm very pleased to start with the Lars Christian. Thank you very much.

Lars Christian Bacher^ Thank you, Peter. Good morning, everybody, and welcome.

Equinor delivered good overall operational performance. We report stable underlying costs, strong progress and deliver on projects, including the early start-up and rapid ramp-up of Johan Sverdrup. Nonetheless, our financial results for the third quarter are impacted by lower prices for both gas and liquids.

Our results are also impacted by lower production levels as a result of deferral of gas production on the NCS to periods where we expect higher prices.

We reported impairments in the quarter, mainly due to more cautious, long-term price assumptions. Let me come back to this later on.

Let me first share with you the positive industrial progress we have achieved, perhaps one of the strongest quarters we have ever had. Since second quarter, we have brought 5 fields onstream: Trestakk, Mariner, Snefrid Nord, Utgard and our flagship, Johan Svedrup.

Johan Svedrup started producing on the 5th of October, more than 2 months ahead of and NOK 40 billion below plan at PDO submittance. The production ramp-up is going very well with 5 wells already onstream producing more than 200,000 barrels per day.

During November, we expect all 8 predrilled wells to be in production with a total capacity well above 300,000 barrels per day. We expect to reach plateau production of 440,000 barrels per day during summer 2020 after drilling 2 to 4 additional wells from the new fixed drilling platform.

Let me remind you at plateau in 2020, the expected unit production cost is below $2 per barrel and average cash flow from operations after tax of $50 per barrel at an oil price of $70.

Since the end of second quarter, we have also achieved major industrial and strategic progress in our offshore wind business. We secured the opportunity to develop the world's largest offshore wind project located at Dogger Bank offshore U.K. Together with the Empire Wind project of New York, Dogger Bank makes Equinor one of the leading players in offshore wind.

These are projects that plays to our strengths, projects where we expect to achieve attractive returns.

2 weeks ago, we presented the development plan for Hywind Tampen. This will be the world's largest floating wind farm, powering and reducing carbon emissions from the Snorre and Gullfaks field. This is an important stepping stone in building up scale and bringing down costs for further floating wind projects.

Equinor entered into the German offshore wind project, Arkona, in 2016 with a 50% interest. Our share of the total investment has been just above EUR 500 million. On October 3, we announced the divestment of half of our stake for around EUR 500 million, covering almost all our reinvestments to-date. This clearly demonstrates value creation.

We are on track to deliver the guided profitable growth and strong cash flow over the coming years. For this reason, we decided in early September to strengthen the capital distribution to our shareholders.

We commenced the first tranche of a $5 billion share buyback program. In this first tranche, we will initially buy back $500 million of shares in the market and then buy the additional $1 billion of shares from the government following the AGM next year.

In addition, the Board has decided on a cash dividend of $0.26 per share also for third quarter.

Before discussing the quarterly results in more detail, allow me to share a few words about safety. Dorian is the strongest hurricane ever to hit the Bahamas, creating a major crisis for the country. Thankfully, all of our 54 colleagues in the Bahamas made it through safely, but several have lost family members and their homes. Equinor is committed to the cleanup, and we work closely with the Bahamian authorities.

This quarter, we reported Serious Incident Frequency of 0.6 per million hours worked, up from our record low results of 0.5. Safety and security is priority #1 for Equinor. We will continue to work systematically to reduce the number of incidents.

Now to the financial results. The IFRS result is negative $470 million, and this includes impairments and provisions of some $3.4 billion. The IFRS result after tax was negative EUR 1.1 billion.

In the quarter, we have updated our planning assumptions with a more cautious outlook on long-term oil and gas prices. This impacted the book value for some of our assets, notably in U.S. onshore by USD 2.2 billion out of a total of USD 2.8 billion in impairments.

We work continuously to improve robustness going forward. This part of our portfolio has contributed with positive earnings over the last few quarters.

Adjusted earnings before tax were $2.6 billion this quarter compared to EUR 4.8 billion in the same period last year. This reflects a realized liquid price of $52.5 per barrel, down 22% from last quarter, realized gas prices down 26% and 23% in Europe and North America, respectively, and 8% lower production.

We have actively mitigated the impact of low gas prices in the market. First, we sold volumes when the prices are higher, achieving realized gas prices 50% higher than the average NBP spot price. Second, we deferred volumes compared with higher expected prices.

The volatility in the market is a reminder of the importance of maintaining a strong cost focus, and we report stable underlying operating costs.

The tax rate on adjusted earnings in the quarter was 59%, the same as last year. The effective rate for DPN was 69%, slightly below guiding due to a higher impact of tax uplift. The international segment had a tax rate of 34% while MMP had a tax rate of 42%, reflecting the strong results from liquid trading with lower tax rate.

Our adjusted earnings after tax was a positive $1.1 billion compared to $2 billion in the same period last year. Then some comments to each of the segments.

E&P Norway delivered adjusted earnings before tax of $1.7 billion in the quarter compared to $3.4 billion last year. The realized liquid price was impacted by high share of NGLs, which had high differentials to Brent in the quarter.

In addition to the price effect, production in the quarter was lower. This is due to deferred flex gas volumes in this quarter while producing high flex gas volumes a year ago. We also had lower production from partner-operated fields and some higher unplanned losses in the quarter.

Snorre is on the process of ramping up again.

As is customary in the third quarter each year, turnaround activity was high, and the impact on production was similar to last year.

E&P Norway continues to control costs, reporting stable underlying OpEx and SG&A. This is a very solid base to build competitiveness and growth going forward.

E&P International reported quarterly adjusted earnings of $435 million before tax versus around $1 billion last year. Production was strong at 842,000 barrels per day in the quarter. And in addition to the price effect, the share of gas in production mix was higher, impacting the average realization. The international segment also delivered underlying OpEx and SG&A costs at the same level as in the third quarter last year.

Adjusted DD&A was up 6% as normal assets in start-up phase have higher depreciation rates. The increase from new fields was partly offset from fields in production with higher proved reserves estimates.

Then to the MMP segment. MMP delivered adjusted earnings in the quarter of $448 million compared to $481 million last year, reflecting strong trading results. This included a really strong performance from liquids trading in a backward-dated market. We also had solid results from our gas marketing and trading operations in Europe. The result was impacted by lower sold gas volumes in Europe and a small loss in U.S. gas, reflecting weaker differentials.

Equinor's group activity -- sorry, Equinor's group equity and production in the quarter was 1,909,000 barrels per day, down 8% from the same period last year. Natural decline on existing fields remains stable. Aasta Hansteen, Mariner and new wells, especially gas onshore U.S., are the main contributors to new production this quarter compared to third quarter last year.

The 5 fields brought onstream since the second quarter of this year are expected to add more than 200,000 barrels a day on average to Equinor in 2020.

During the first 9 months of the year, we delivered a cash flow from operating activities of $16.6 billion. In aggregate, we have paid more than $5.6 billion in tax this year and close to $2.6 billion to our shareholders through dividend payments and share buybacks.

On our share buyback, at the end of the third quarter, we had acquired around 5.5 million shares in the market for a total consideration of $91 million. At the end of business yesterday, we had acquired 11,880,851 shares for a total of $223.3 million.

Third quarter net debt ratio is 22.5%, up from 19.9% in second quarter, mainly due to currency effects, impairments and the first tranche of the share buyback program, where we have fully booked the $500 million market order.

In the quarter, we had organic investments of $2.6 billion, taking us to $7.4 billion year-to-date.

Our net cash flow, including inorganic investments and divestments as well as cash dividends and share buyback, is $337 million.

In the quarter, we also closed the Lundin transaction, which increased our direct ownership in Johan Sverdrup to 42.6% and booked a profit to our IFRS results of $837 million. We have also closed the Caesar Tonga transaction, increasing our share in the fields to 46%.

Let me conclude with our guiding, where we remain on track. Last year, we delivered record-high production, and we expect to maintain production around this level for 2019. From 2019 until 2025, we maintain the guiding of a 3% annual average production growth rate. We maintain our CapEx guiding between $10 billion and $11 billion, and we also maintain our expected exploration expenditure level for the full year at around $1.7 billion.

And with that, we now open up for your questions, and I'll pass it back to you, Peter. Thank you for your attention.

Peter Hutton^ Thank you, Lars Christian, and I'll pass it through to the operator to get us going for Q&A.

+++ q-and-a

Operator^ (Operator Instructions) We have a first question from Christyan Malek from JPMorgan.

Christyan Fawzi Malek^ Two, if I may. First of all, just regarding your long-term macro assumptions. And also it's surprising this morning to see a slight adjustment through both the medium-term and long-term view. What prompted that? And should we expect further revisions impairments based on additional movements on your long-term assumptions?

And it's just quite interesting to see that despite the change, you're still expecting $77 and above over the medium term by -- where the back end of the curve is. I'd like to, a, understand the logic behind that; and, b, sort of the scope for potential further charges over the medium term if that's reviewed.

And the second question comes back to capital allocation and degree of sort of capital employed through your non-oil and gas business and to what extent your gearing will be accommodated for additional acquisitions, both in oil and gas and non-oil and gas. And do you have a cap in terms of scale or books of sizes of acquisitions that you're looking at? And I guess, sort of it relates back to the first question, which is if you do see further revisions, how would you frame your gearing in the context of that and sort of those over the next 12 months?

Lars Christian Bacher^ Thank you. In every quarter, we look at our price assumptions and make changes related to sort of the forward prices short term in the market as, is the case for this quarter. In addition, once a year, we have a revision internally around more of the medium- and long-term price assumptions.

We are in a long-term industry with investment horizons of 30, 40 years and we thereby need to have a long-term view on all the commodity prices, including differentials. This is a thorough assessment done internally. And as a part of the input, we then are also, of course, looking to walk the different agencies and others have overview externally. And these curves are sort of in a little bit below the mid-range of that spectrum in time.

So on further impairments, I mean, there are triggers from time to time. And at those points, we need to then assess, but there is a reason to do an impairment or a reversal of impairments. Historically, we have done both. And this time around, the price revision was a trigger, and we ended up with a total of USD 2.8 billion in impairments. USD 300 million is related to an offshore asset in the Gulf of Mexico that was not triggered by price. It was more as a consequence of reserves revision. We have USD 200 million related to South Riding Point at Bahamas and then around USD 100 million related to a third asset. Before then, USD 2.2 billion is related to the onshore U.S. business, which, those of you who have followed us for a period of time, have seen that before the dawn impairments and reversal impairments historically.

These are assets that we have acquired. Thereby, they have a higher sort of entry book value compared to other assets that we haven't acquired. And then, of course, you know that you'll depreciate, but, still, if you have a revision of where the book value is -- shows to be too high, then you need an impairment.

There is no sort of indication in these numbers or these price curves that you should expect further impairments or reverse of impairments that is for the future to decide. Of course, we work hard every day with these assets, as we do for every other assets in our portfolio, to improve our competitiveness to reduce the cost of running them.

On capital employed, we said that when we introduced the script -- sorry, the share buyback program that, that didn't stop us from doing acquisitions. That is the case. We have closed the Lundin sale this quarter, but also the acquisition of Caesar Tonga and the 2.6% equity in Johan Sverdrup. We do not operate at any numbers in the market as a sort of what the levels we are looking at or -- we are looking for the best assets and the best opportunities.

Operator^ We have the next question from Biraj Borkhataria from RBC.

Biraj Borkhataria^ Two, please. The first one on -- just wanted to get your perspective on NCS production. When we look at liquids production in Norway, it's been consistently below the NPD forecast every month for the last couple of years, and your volumes are generally quite well correlated to that. I was just wondering if you could touch on your perspective on what is happening there. How much input do you have into the forecast from the NPD? I'm just trying to get a sense of whether it's an issue on very, very optimistic forecast or production disappointing?

And the second question is on cash taxes in Norway. I think, previously, you talked about the first half of 2020 cash taxes almost being NOK 12 billion in each installment. Could you just confirm whether that figure is confirmed for the first half of 2020 or whether that's an indicative figure based on commodity prices a few months ago?

Lars Christian Bacher^ Thank you. First of all, NPD is not Equinor. We have our forecasts and report our numbers. And the view NPD have, I'll have -- you need to ask them, I think. On the sort of the tax installments for next year...

Svein Skeie^ Yes. I will comment on the tax installments for this year, firstly, because how it works in Norway is that you pay half for the tax the year it happens and half of the tax the year after in 3 installments, each of that year. We did an assessment in June. And then and our assessment, based on that one, is that we're going to pay NOK 12 billion in the installments for the second half of 2019. Going out of 2019, then we will learn to do full calculations of the results that we have achieved based on the actual production, based on actual prices in those. And then in February, then we will come back to what the actual payments will be then for the 3 last installments. That will happen in 2020. So that's how it works because then we do it on their results.

Lars Christian Bacher^ And to give you some more meat on the NPD, all the operators on NCS, they report or give input once a year. And the sort of the discrepancy in the numbers, in many ways, is related to sort of assets that others are operated for, and we usually do not comment on that. So....

Operator^ Next question comes from Oswald Clint from Bernstein.

Oswald C. Clint^ Two questions. First, back on the impairments and primarily U.S. gas, I remember starting the year talking about the research and development and the marketing and trading and kind of all of that helping to make this -- let's have a stronger, more robust, onshore, unconventional business. But, obviously, you ticked $0.50 or $1 per Mcf off your gas prices, you end up with these large impairments. So you're still running with $3 to $3.50 per Mcf long-term Henry Hub gas prices, but do you think the work you do in this asset can get it down to working $2.50 per Mcf long-term Henry Hub gas price level? That's my first question.

And then secondly, I noted that Ørsted got the pricing for the New York wind farm last night. I wonder if you guys got yours. It looks pretty favorable for Ørsted. I wonder if you have a price and what sort of implied unlevered returns it's kind of indicating towards last night's, please.

Lars Christian Bacher^ Okay. Let's see. The first question is around sort of whether we could get it to work around the Henry Hub price of

$2.50 per MMbtu. The midstream position that we have taken has historically served us well. We have seen, as always, in the U.S. market that whenever there is a sort of arbitration advantage to some others, we like to tap into it. So that has softened somewhat, but we have worked hard to bring down the costs and improve our sort of operational performance. We participated in a benchmark close to a year ago, where we are quite well off compared to the competitors. But as always, and that's why we participate in benchmarks like this is that that's a source of identifying kind of where you have further room for improvement, and we are working hard to make that happen. The future will tell, but we are able to bring it all the way down to sort of that 2.5%, as you referred to.

On the renewables, Empire Wind in New York, both in case of that asset as well as the Dogger, the work that we are doing now is needed in many ways for us to be able to come up with a view, a firm view on the level of return that we can expect from these assets. Having that said, I've said before that we are searching the whole sort of opportunity set for renewable opportunities, high level of competition, very pricey sometimes. And then that's when we don't choose to bid. There are some projects that we view to be sort of better fit to our strength, but also of a nature and a scale that we believe that we can get sort of a good return, given the risk profile for these assets. So it's too early to conclude. So we have to come back to that one.

Operator^ We have next question from Thomas Adolff from Crédit Suisse.

Thomas Yoichi Adolff^ Two from me as well, please. Just firstly on Johan Sverdrup, you've got your 8 predrilled wells, which you'll hook up by the end of November. And then, I guess, my question is, the 2 to 4 wells you need to reach the plateau production, do you plan to drill right after you -- the 8 wells are hooked up? And I guess, how long does it take to drill, complete and hook up the remaining 2 to 4 wells? I'm just trying to understand the best-case scenario when Johan Sverdrup could actually reach a plateau. Could it be as early as 2Q next year?

And then secondly, just perhaps, I do apologize for the ignorant question, but just wanted to ask if you can run through the decision-making process or the maths behind whether or not one should use the flex volumes in Norway in any given summer. Presumably, in the winter, you don't have much flexibility on the volumes you alone, so whatever decision you take this summer will be a function of your view maybe of the next summer or the summer thereafter. If you can just quickly run through the thought process here would be great.

Lars Christian Bacher^ Thank you. First of all, on Johan Sverdrup starting up 5th of this month, and now we are sort of 19 days later 5 wells in production producing about 200,000 barrels a day, I mean, it's a stellar performance.

As I said last quarter, we have never operated the plant and never sort of produced this reservoir. And so far, both of them are delivering excellent. When we then, also, starting off 5th of October, are saying that we do so a couple of months earlier than the plan for -- than what was the plan when we submitted the development plan for -- to the authorities, that has -- in that process. Of course, we have price ties to try to get up early production, which is then the case. But this drilling rig that we're talking about, which is a fixed one, a totally brand-new one that we have built, there is still some remaining work to be done before that is fully complete, and that's why the starting up of drilling additional wells will commence towards the end of this year. If it had been already ready, we would have obviously started already drilling.

And how long it will take, when we guide on plateau 440 around summer -- during summer next year, then we'll have a view on how long it will take to drill the additional 2 to 4 wells needed. So if you'd only need 2, 3 wells, it will be sort of early summer. If you also need the fourth one, it will be during summer next year. So unfortunately, at this point in time, I can't be more firm on this.

But I hope that we -- when we get to the Capital Markets Day in February, and we have more production history and we have started drilling and that kind of stuff, that we can be -- give you more granularity and a more firm view on when we will reach a plateau and if that is going to be different.

The second question was related to the flex gas and the capacity that we were having. For our flex gas to really work, you need to have the capacity to increase your production again to catch up whatever you have deferred. And that is the beauty with a couple of our gas machines on the Norwegian continental shelf. So us limiting ourselves during the summer doesn't mean that we have to produce that next summer. It can mean that we can produce it coming winter if the prices are healthy and we choose to do so.

Then I'm not sure whether -- perhaps I should touch on this now since I got a question on Johan Sverdrup. We -- I have gotten another question before. It's going to be a discount to brand given the composition of this oil. And we have said, yes, it's going to be a very small one. And so far, it -- the reality has shown that it's less of a discount than what we sort of foresaw in the beginning. But still it's too early to judge these kind of new volumes at this -- the magnitude that we're talking about. It takes some time before the market gets used to it and have a view on the quality of this and how to adapt. And that is how much the market is seeking this kind of barrels to put it like that.

Another, sorry, tweak to this is -- no, no, I'm not only answering your question, I'm trying to build on it for you and for the rest of those of you that have called in. Another aspect of the quality of this oil is actually that there are no natural gas liquids as part of the production mix. So that means that realized liquid price for these barrels will be quite good compared to the portfolio that we're having. And you could also argue that given the magnitude, we're talking about volume-wise, how big of an impact that will have on the total liquid mix of the company, our average realized liquid price on the totality of our portfolio, you should also expect to rise somewhat. So this asset definitely will have a big impact on low operating cost per barrel, high volumes, low emission, but also good price for these assets in such a good price and volume impact that it will actually influence the composition of our liquid prices.

Thomas Yoichi Adolff^ Can I quickly just go back to the flex gas volumes? You said that you can produce some of that flex also in the winter season. So I guess my question is, if so, have you already produced it? And you've got it in storage, so that you can release it in the winter when prices are higher or can you -- do you actually have the capacity to produce much more than, say, the winter of last year? So it's not about storing it, it's simply a function of ramping up production and capturing the higher demand and prices.

Lars Christian Bacher^ These volumes are stored in the reservoir on those producing assets. So we haven't produced them, yes, but we have capacity to produce during winter if we choose to do so.

Operator^ We have the next question from Lydia Rainforth from Barclays.

Lydia Rose Emma Rainforth^ One realatively quick one, if I could. In the press release, Eldar talked about it being kind of game-changing a few weeks and months for the wind part of the business. Can you just go through that in a little bit more detail? And at what stage do you think that becomes significant enough to break out into a separate reporting? And I know I'm thinking in particular around the value it creates around Arkona as an example of that.

Lars Christian Bacher^ Thank you. There are several projects that Eldar then allude to or speak of as part of this renewable sort of step-up. Hywind Tampen -- let me start with Hywind Tampen, which is floating offshore wind mills, 11 in total. We have gotten support from a Norwegian sort of governmental body of NOK 2.3 billion as part of this, and that is their view on wanting to help out to bring such a project at this scale into reality because this is a stepping stone for kicking off more improvements in the area of floating offshore wind. And the floating wind has a bigger potential than bottom fixed wind if you look at the globe and how this works. And we then, by that, hope to see that we, over time, will start to get the same reduction going down the development curve and the operating cost curve for floating wind, as we have seen on bottom fixed wind installations.

The Arkona deal, I think, is a very good illustration of a way of illustrating value creation, but also monetizing on good opportunities. By this deal, we are not signaling that we're going to do it with all our projects going forward, but we will choose to do so from time-to-time, as we have done and do for oil and gas. So we will treat this segment the same way as we did treat oil and gas.

The size of the Empire and Dogger are of such a nature that we are really a major wind developer and producer as a result of this. And we expect, as I said, good sort of returns on a risk basis for these 2 projects. This will, in many ways, when we have said 15% to 20% of our CapEx in 2030 related to renewables, these 2 projects, you can say that we are taking off that a couple of years earlier.

So to your last piece of the question, when will we start reporting this as a separate segment, too early to judge. Even with these projects compared to the oil and gas part of the business is not going to be a material piece. But from the starting point, it's going to be a sort of a substantial growth in that piece. Ørjan?

Ørjan Kvelvane^ I just want to add that kind of the required...

Lars Christian Bacher^ Ørjan?

Ørjan Kvelvane^ Yes. I just want to add that the requirement for reporting a separate segment is 10% of the assets or the revenue or the net income. So -- but we can choose to do it earlier, and that is kind of an ongoing discussion into the future.

Lars Christian Bacher^ Great.

Operator^ We have the next question from Martijn Rats from Morgan Stanley.

Martijn Rats^ Yes. Also sort of 2 from me, if I may, please. First of all, I just wanted to ask you what you -- what now your internal estimate is of what your breakeven oil price is, i.e. oil -- Brent averaged $62 for the quarter. You only had one tax payment, yet free cash flow was below the dividend. And I guess that has to do with lower gas price realizations, the NGL realizations not being perhaps quite what you hoped they will be and also perhaps your own crude realizations being sort of below data of Brent So can I ask, with all these external variables, what would now be your internal assessment of the required oil price that you would need to cover the dividend organically?

And secondly, I wanted to ask you about your trading results, which seemed very strong. And I was wondering, if you could highlight perhaps what the nature of the bid was. And to what extent there could be a degree of sort of replicability to it in coming quarters?

Lars Christian Bacher^ Thank you. The liquids -- the trading results are very, very strong, USD 253 million across products and crude trading. This is mainly driven by global arbitrage for gasoline, in addition to strong European optimization across all products. And this is still very, very strong results in a backward-dated market. Have we achieved sort of strong results in backward-dated markets before? Historically, yes, we have. Every time, no. So whether it's replicable or not is for the future to demonstrate and judge, I guess. But of course, our employees working in this area are trying to do their utmost every single day to make money.

On the cash flow question and the breakeven, we -- I mean, we are still of the view that we will be cash flow positive below $50 a barrel after investments, dividends and tax, but so no change compared to what we said at the CMU. But that, of course, is before the share buy -- introduction of the share buyback program. So that amounts around $5 on top of the below $50. Svein?

Svein Skeie^ So just a comment. Since you commented, the third quarter, I remember that the third quarter has a high turnaround activity that we have had and also the deferral of the gas production, which impacts the quarter in itself.

Lars Christian Bacher^ Yes. And I think also, third quarter is a perfect illustration that we have the strength to continue to do sort of M&A. And we acquired Caesar Tonga and the Johan Sverdrup at 2.6% for this quarter, which was sort of -- a bigger sort of cash payment from us than what we received for the Lundin deal. So yes.

Operator^ We have the next question from Anders Holte from Kepler Cheuvreux.

Anders Torgrim Holte^ Just 2 questions for me. First one is on Johan Sverdrup and the impact it will have on your first half cash flow for 2020. I know that you are, as a good CFO, cautiously guiding on the ramp-up, but, nonetheless, I guess the tax payment in the first half next year will be related to 2019 results. And as such, the cash impact from the barrels produced at Johan Sverdrup will be pretty significant in the first half. And if we can confirm that the uplift that we'll see in Q1 and Q2 will then come to slowly a halt in the second half of this year due to the tax effect? That's the first question.

And then second one is more related to our offshore wind projects, Dogger Bank and Empire Wind specifically. Now those 2 projects will bring you pretty close or above your target of 15% CapEx going to renewables. My question is, are you willing to put those investments to an equity account with an investment vehicle? Or are you willing to gear those investments above the 15%? Or is the 15% your actual money equity account that's going to go out from Equinor into renewables?

Lars Christian Bacher^ Okay. On Johan Sverdrup, we can confirm that the cash margin for 2020 at $70 a barrel will be $50 net to the company. So it's going to be a strong cash generation capacity based on that asset. When we have said 15% to 20% or our capital spending in 2030 in the segment of renewables, whether that is sort of equity funded from our side or deleveraged, that remains to be seen. And we answered that we have to either -- whether that 15% to 20% is going to come on top of -- or as part of the current level that we are running at around USD 11 billion. I mean, this is out in time. It's an ambition. And what we have been clear on towards the renewable segment internally is that it's not a volume target. It has to be value. And we believe that the Dogger Bank project and Empire Wind project is among those that are on a high note in the renewable space. Any other sort of comments to the cash, Svein or Ørjan?

Svein Skeie^ No, it's -- as we said, it's -- we have also used an equity accounted investment for the renewables. So until now, for example, Dudgeon is project-financed. We have in Arkona an 50% equity accounted for, and even though it's not a project financing that one. But we're also working with potential then for the project financing in the Dogger Bank project. So we are working on to see how to optimize the value here.

Lars Christian Bacher^ And project financing. I mean, that is also something in that we, from time to time, do it in the oil and gas space. Tanzania gas development most likely will be project-financed.

Anders Torgrim Holte^ Okay. So the 50% is -- it's depending on, I guess, the cost of capital, and you are, to some extent, willing to give some of it? I just wondered it. And just if I could confirm. You said $50 per barrel cash margin from the onset of $70 for 2020. Is that for the full year or is that for the first half?

Lars Christian Bacher^ Full year.

Anders Torgrim Holte^ Full year. Yes, so the first half would then be quite a bit above that...

Lars Christian Bacher^ It's for the full year.

Operator^ We have the next question from Alastair Syme from Citi.

Alastair R Syme^ A couple of questions. Can I just come back to the very first question on long-term oil prices? I understand that you've got to make long-term decisions and that the price forecast that you're using is kind of in the middle of many other forecasts. But if you look back over the last 30 years, real oil prices have been averaged $77 and then being far below. So I guess the question is, what sort of mindset is the organization running with the sort of this inflationary price view? And do your auditors push back on that view?

And then my second question is, and this is specific on Dogger Bank to help us model it, of the GBP 9 billion of capital, how much of that is rebatable to the U.K. government? Is that for infrastructure costs? And what's the long-term merchant prices that you're using for the 15-year contract for difference period?

Lars Christian Bacher^ On the long-term oil and gas prices, this, of course, is -- historically, it's so easy to look at what has been. It's not always very easy to look at what is coming. If it had been, I think, we all would have been much, much wiser and probably richer, too. When we look at the sort of the market developments for the different segments on a forward-looking basis, we look at what others are all thinking, both on pricing side of it, but also on supply demand and the cost of bringing barrels to the market. The fact that we have, as an industry, under-invested over the last couple of years after 2014 to keep up the production capacity, given the decline. And then it's hard to judge about the growth in GDP globally, somewhat downward risk to that aspect of it, given the trade attentions and so much more. So there's a lot of factors going into this. This is our best assessment. We are open about it, and I think it's a balanced view that we are bringing to you as part of this quarterly statement. And, yes, lot of different factors, a lot of work that has been put into it early on. That's fine.

Ørjan Kvelvane^ Yes, I just wanted to say that this has not been driven by the auditor. So we have our own process. And, of course, then we anchor it with the auditor as part of the process.

Svein Skeie^ But then also, just to your question on the internal part of it and how we're running the company and might take your mind back to the CMU portfolio that we presented, where the project coming onstream up to 2025 a breakeven of 30 and a non-sanctioned portfolio than with a breakeven of the 40s there, as we've shown. And we have improved it a lot over the last years and continue to work on that portfolio to make it robust. So that's also the robustness of -- is also the thinking on how we're running the company.

Alastair R Syme^ Yes. I think it's also -- I'm going to take your point, but it does still feel like there's a sort of a mindset in the organization that says inflationary macro is going to be a tailwind in the future.

Lars Christian Bacher^ I mean, this is the view that we are having on the pricing going forward. And internally, we have a set of sort of hurdle rates that different projects need to be at for them to be sanctioned. That goes for sanctioning oil and gas projects, that goes for sanctioning renewables projects, that goes for what Tim (Dodson)is going to explore for how it's going to buy that they have to have a view on what the value of whatever they're discovering or buying is going to be, including the considerations. And that is not value-adding to us to buy something that has such a high breakeven or low NPV that it will never ever be developed. And so they have to have a view on what the value creation and that these assets can bring and that we do to instill discipline internally, that we do to improve our competitiveness with the sole purpose of being robust versus volatility in commodity prices. And, of course, to make money and even so more money when the prices are high. So I think you should also look at and remember, how we have transformed this company over the last handful of years and use that also as a guiding for how we're going to run this company going forward. Because for us, this is about a brick by brick becoming more and more cost efficient, so that we can deliver better and better results and take on more and more opportunities, good opportunities.

Alastair R Syme^ Okay. And on Dogger Bank.

Svein Skeie^ On Dogger Bank that's still early days. So we are working on that one, and we will come back later on Dogger Bank.

Operator^ We have the next question from Yoann Charenton from Societe Generale.

Yoann Charenton^ I would like to ask on group production. And then on NCS gas volumes. So first set of questions, since your guidance of steady 2019 production year-on-year is adjusted for portfolio measures. Could you please advise on the 2018 base production we should have in mind? You also referred to strong production growth in 2020. Is strong consistent with the 10% annual growth rate? Separately, do you intend to bring volumes associated with NCS gas production deferral to market if gas prices were to remain depressed in the first half of next year? In other words, is it fair to say that placing such volumes in the market is fully dependent on pricing now?

Lars Christian Bacher^ First of all, on production growth for 2020. We have said 3% annual compound growth rate from '19 to 2025, but we also said that it's going to be somewhat higher than the 3% in the short term compared to out in time. So I'm not commenting on 10% at all and not confirming it and not commenting on it, but it will be somewhat higher than 3%. On the deferred gas, whether we will or not. We have flexibility to move volumes within a calendar year and also between calendar years. So we are allowed to move a certain volume from '19 to '20, but if '20 turns out to be a very strong market prices, and we view then that the prices for 2021 will be lower then we're also allowed to lift volumes from next year into 2020. So is -- we are trying to make most bang for buck on an ongoing basis, and that has to do with a short-term view, but also medium- and long-term view. And I think that is the best answer I can give you on that one.

Operator^ We have a next question from Peter Low from Redburn.

Peter James Low^ Just a quick one on gas realizations. The premium to NBP in the quarter you said was a result of your exposure to longer-dated contracts. I think you previously expressed your intention to shift your pricing basket more towards shorter-term indices. Is that still the plan? And over what time scale should we think of that going?

Lars Christian Bacher^ That is still the plan. We believe that the gas prices in season ahead and year ahead is of such a nature that we would like to benefit from a price uptake in the spot market at that point in time. So we are tailing off gradually. We benefit from the 25 -- 25, 25, 25 historically, sales strategy. We benefit from that this quarter. We will do so also next quarter and then during 2020, it will not be that much left, but that doesn't stop us from locking in volumes on a forward basis if we see strong prices are out in time. So this change in gas sales strategy is more to have a more active view on the market, like we do for oil. And hopefully, we will make more money based on that.

Peter James Low^ Just a follow-up, where do you take your view on the price? Any profits you make on that would that be booked in MMP rather than in DPN?

Svein Skeie^ It's a kind of a basket, which is the reference price that goes over to DPN, and we take a deviation from that one. The gains coming from that one will be kept in the MMP segment. So it's the deviation from the basket will be kept.

Operator^ We have a next question from Halvor Strand Nygaard]] from SEB

Halvor Strand Nygaard^
A few questions from me, please. You say the impairments U.S. onshore is due to lower price assumptions and changed operational plans. Could you please elaborate a bit on the new operational plans that you have? And what that implies for activity, production growth and for which particular shale plays. Then on your new price assumptions, seeing that your price assumptions are maybe 20% to 50% above the current forward curve. So as the sensitivity, what would be the impairment effects, if you were to use the forward curve instead?

Lars Christian Bacher^ I mean, we are using the forward curve next 3 years as we are required to, and then we are also asked to have a view our own out in time, and that is what has been reflected in this price sort of table that we have provided. When it comes to sort of sensitivities around the ...

Halvor Strand Nygaard^ But the longer-dated prices than 25 and 30, please?

Lars Christian Bacher^ Yes. But when it comes to sensitivity in our results based on prices deviating from what we have given you at the CMU in one of the appendixes. You see the impact on sort of contribution after tax based on whether that is sensitivity around the oil and gas prices and whether -- and how that is going to impact the level of impairments that we have not transitioned of giving you. And I am not planning to do so or start by that now.

We -- on the impairments, U.S. onshore, it's mainly related to price, as we said, but also business plans going forward, and the business plans revisions has not that much to do with sort of a change in activity level going forward. It has more to do with sort of our assessments on what we get out of the reservoir, given different measures. So this is just sort of to factor in what we have seen of performance over the last couple of years.

Halvor Strand Nygaard^
Okay, fair enough. Just a quick one here. The NGL share of production was relatively high in Q3, up 23%. With the production mix that you now foresee for 2020, what would that share be for 2020?

Lars Christian Bacher^ I don't comment on that now. But you're right, we have said historically, we said that last quarter that NGL content it is sort of typically be between 20% and 22%. Last quarter, we saw 24-ish, and I see kind of the same level for this quarter. And then I think you can just do the math on Johan Sverdrup contribution, not having NGL and then you get a good indication yourself, I think.

Operator^ We have a next question from Alwyn Thomas from Exane BNP Paribas.

Alwyn Thomas^ Just a couple of sort of forward-thinking ones from me. Firstly, on the upcoming Brazil [Tyra 1 round] I know there's no direct overlap with your existing assets in Brazil. But I was just wondering what -- we've -- what you think about the terms, whether there's likely to be some active interest from Equinor. Some of your peers have talked about terms being pretty challenging. I just wanted to try and get your thoughts?And secondly, I guess, coming back to the renewables outlook again, and I guess, where the business is going from next year onwards. Congratulations on delivering Sverdrup. It's a fantastic project. But it's a big milestone for the company. And I'm just sort of thinking going forward for your North Sea business, around the deployment of capital and people from the next -- during the next few years. So we'd like to see shift, obviously, into wind. But beyond that, do you think the company will become a little bit more active in areas like carbon capture storage, hydrogen, perhaps more venturing, just some color around that and whether maybe you're looking to give a bit more detail on that at the CMU in February?

Lars Christian Bacher^ I think on your last point on addressing some of these issues at the CMU and later, I think we will do so. We have signed an MOU with several other companies in Europe related to a project called Northern Lights. That is also one initiative to see how some companies or industries in Europe that is very dependent on actually burning hydrocarbons for their processes. Electricity will never give them the high temperature they need for aluminum production or cement and so on. So they need to find a solution for the emissions part of it for them to continue their business in Europe if you factor in where many believes the policies and the requirements in Europe is heading. And then to capture that CO_2, you need to sort of be able to transport it and reinject it. And that's where we are coming into the picture. So this is a collaboration between many, many companies. Too early to tell how this is going to be panned out. But I think this is another sort of illustration of Equinor playing a role and being active in trying to take positions that can move the industry and also the world forward.

On the transfer rights, you are right. It is a high competition, and I've always said that if companies are saying they're not looking at it, I wouldn't have given that much thought to that because I think if you're a serious oil and gas company, you have to look at this because this is the biggest the yard sale for a long, long time and for a long, long time to come. Then it's my question of the terms, and that is exactly what you're saying. It's about whether this is commercially attractive. And that there, of course, is a function of the bonus that you have to pay and also eventual conversation compensation that you need to bring to Petrobras, the development and the insight of the quality of the assets and all that comes. It's a long, long, long list. And I think all the companies are in the same boat from the point of view that it's a lot of moving parts, and you need to have an assessment of whether this is commercially attractive or not. Your view on that might differ from company to company, but we are not willing to go into projects that we do not find commercially attractive enough. And for us, what is enough that has to sort of fit nicely into the rest of our portfolio. We have high-graded our portfolio over the last couple of years, $10 billion in capital gain from the M&A deals that we have done over the last -- almost a decade. And today, we have a very low breakeven on the producing portfolio. It's going to be even lower with Johan Sverdrup and other assets coming in onstream. And we will not accept that to deteriorate as a consequence of taking a big bet on anything in this transfer rights process. And to be honest, in Brazil, we have a lot on the plate already. We have Peregrino, Peregrino Phase II coming onstream. We have quite Carcará all that we secured and [Paudasucar] we have exploration acreage, [Eurapudir] belt start drilling at the back end of this year. And so if you get something in this, it's fine. If you don't, well, we are more than enough on the plate. So this needs to fit nicely into our portfolio.

Operator^ We have a next question from Jason Gammel from Jeffries.

Jason Gammel^ I had 2 questions, please. The first is just on the Arkona equity sell down, that seems to be a transaction where the merits are fairly apparent. But the question really is, is this something that is a one-off transaction or do you think this is a repeatable tactic where you could take high equity stakes, relatively high equity stakes in predevelopment projects and then potentially sell down equity post completion to parties willing to accept lower rates of return in order to enhance the overall returns on your wind business? The second question is, I'm really just trying to understand the mechanics of the government participation in the buyback. So I understand that at the next general assembly, they will be redeeming a billion of shares. My understanding is that, that is at no cash cost to Equinor. But I assume that you will be debiting your share capital by $1 billion. Can you help me understand what -- sorry, I understand, what the credit side of that transaction would be?

Lars Christian Bacher^ Okay. Whether Arkona can be repeated or not, the divestment and monetization of that, it can be from time to time, but I think if you want to grow in renewables business, it's kind of whatever you need to sell or want to sell, you need to backfill in, if you want to grow. So we are going to look at high grading and making -- taking positions in the renewable space as we have done for a long, long time in the oil and gas space. So by that, I'm saying it might come one day in some cases and it might not come. So it's not -- you can't read any sort of promise out of this. But you can't read that I'm ruling it out either. So it's, in many ways, a political correct answer and perhaps a boring one, but we are not tradition of telling you upfront what we're going to do and so on, because I think we are just giving away sort of bargaining position towards potential buyers or sellers, if we are ever on a buying strike.

On the government participation in the share buyback program, this is just a pro rata. Whatever number of shares that you are buying in the market, they are going to match in such a way that their equity and the totality of the shares in the company is going to stay flat. So you could argue that when -- in many ways, it's how many shares does the company going to sell, it depends on how many shares that we are going to buy in the market. So every single day, when we buy shares -- if you buy 100 shares today at a certain price, we put that into a spreadsheet. Then we know that on that day, we should have bought twice as many shares instead of 100. It should have been 200 shares in addition from the Norwegian government at the same price. They don't get the money today. So when we come to summer next year, they're going to say to us -- and this is kind of an upfront agreed. So then we need to do some interest calculations on top of this to compensate for them for not getting the money today, but they have to wait. So it's a tedious, long, big spreadsheet coming to be since this is going to be over that many days and transactions, but it's pretty, pretty straight forward.

For this to be renewed and prolonged, we need a renewal of the share buyback program at the AGM, including the agreement that we signed on the day with the Norwegian government for them to participate on a pro rata basis. We've gotten that every single year for the last many, many years. So we don't expect that this ends up being an issue at the AGM. But at the same time, it's not prudent of us to take it for granted either. So that's why we have said that when it comes to the AGM, we need approval for those 2 contracts and then the size of the tranches. And such is dependent on -- or conditioned on renewal, but it also depended on balance sheet strength and commodity prices in addition to the opportunity set that we might be seeing at that point in time.

Jason Gammel^ Okay. So just I'm clear, at some point in time, there will be $1 billion transferred from Equinor to the Norwegian government for their participation.

Lars Christian Bacher^ Correct. Interest on top of it.

Operator^ And we have a next question from Christopher Kuplent from Bank of America.

Christopher Kuplent^ Just 2 questions for me to clean up, please. Are you willing to tell us what your long-term commodity prices are today, that have led to the impairment, whether it's Henry Hub, WTI, Brent or whatever? Or at least the delta in terms of how much you've downgraded them by for us to get a little bit of a flavor of where you're sitting? And second question is on the cleanup costs for the Dorian. I think you've built a provision of more than $0.5 billion. Can you give us a bit of an idea of how that's going to be spent, when, over what kind of time period and whether you've already incurred cash costs in Q3?

Lars Christian Bacher^ Okay. For the price deck, to put it like that, both for Brent, Henry Hub and NPD for the years 2019, 2025, 2030, you will find on Page 26 in the financial statements and review third quarter 2019. And just to pick 1 year, you will see then that the Brent price is down 2.4% compared to the previous one. You will see that NPD gas prices are down north of 8%, and the Henry Hub is taken down slightly above 12% for that specific year compared to the previous price stack. But you see both the previous one and the new current one for the period 2019, 2025, 2030 on Page 26.

On the provisions for the quarter, totaling USD 600 million, there is one related to an honors contract and then there is the cleanup and costs related to the South Riding Point. I'm not confirming your number that you referred to that, that is going to cost us. Yes, we have incurred some costs related to cleanup for the quarter, but the majority of those costs is to come. Having that said, there is a huge uncertainty related to that number. A lot of moving parts, and we're still working on trying to get an overview and an assessment of what this is actually going to cost us. So going forward, most likely, that number will move, but this is somewhat of a conservative number in the provision.

Christopher Kuplent^ And could you confirm, is this a matter of 4 to 6 quarters? Or do you expect this to be stretched over a period of years?

Lars Christian Bacher^ The cleanup is not going to take years as such. But then, it's also a question of rebuilding and repairing this plant, and we also need to have a clarity around sort of the insurance and all that. So it's a lot of moving parts there on this one, but it will take time.

Peter Hutton^ Thank you for everybody for joining the call. We appreciate that one, and thank you very much, indeed.