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Aker BP ASA (AKRBP.NO)

Q4 2021 Earnings Call

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MANAGEMENT DISCUSSION SECTION

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA

Good morning. Welcome and thank you for tuning in to Aker BP's Fourth Quarter 2021 Presentation and Conference Call which will be hosted by our handsome, I mean, hands-on CEO, Karl Hersvik; and our always energetic CFO, David Tønne. And after the presentation, we will open up for questions. If you prefer, you can also send us your questions by e-mail to ir@akerbp.com.

And with that, here is Karl.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

Thank you, Kjetil, and good morning to all of you. So, first of all, Kjetil, I'm very glad that you corrected the handsome to hands-on. I much rather be hands-on actually. So, today's presentation is going to be somewhat expanded compared to our regular quarterly update. We will, of course, take you through the quarterly and annual highlights, but we will also go a bit deeper into the company's strategy and priorities and we will present our guidance for 2022 and updated outlook for production and CapEx.

I'm sure that many of you are very keen to hear about the combination with Lundin Energy, which was announced on December 21 in – last year. However, due to certain legal restrictions, we are not yet fully able to discuss the combined company in public, but we will cover the process and timeline for the transaction. Apart from that, today presentation will focus on Aker BP as a standalone basis.

Now, let us kick off with the highlights for Aker BP in 2021. And to say the least, another eventful year is behind us. On the back of tailwinds in the macro environment with continued strength in oil price and the European gas prices reaching records high in the second half of the year, we've delivered yet again record-high free cash flows despite investing a significant amount in progressing the project portfolio and exploring for high-value barrels on the Norwegian continental shelf.

We are clearly happy with realizing high prices and we never forget that commodity prices are completely out of our hands. This means that in order to deliver on our ambition to be the leading company in our industry, our priorities need to focus on the things we can actually impact and improve. Operational efficiency, safety, capital efficiency and emissions are key focus areas in this respect. And, of course, more on this in a couple of minutes.

Turning our attention to the project hopper, I'm pleased to see that all project that we plan to submit to PDO by the end of 2022 as well as project in the execution phase are progressing well throughout – during the year. We are on track to deliver all projects on time and budget, while working relentlessly to ensure that we maximize value by developing and improving them right up until the finish line.

During the year, we submitted three PDOs. We completed our Ærfugl on time and on budget, and we made excellent progress on Hod and Johan Sverdrup Phase 2. As we are embarking on the next wave of growth project, we are also stepping up our digital transformation to further streamline the way we develop and operate our assets. I am very pleased with the way the entire organization, and I must say in close collaboration with our alliance partners, is working to deliver low-cost, low-carbon barrels to spur the next leg of production growth for Aker BP.

And a 2021 review would not be complete if we didn't mention the Lundin transaction which was announced in December. With this transaction, Aker BP will take over Lundin's oil and gas activities. In exchange, Lundin shareholders will receive 0.95 Aker BP shares and $7.76 in cash for each Lundin share. After this, Lundin Energy will continue operating as a renewable energy company and remain listed in Stockholm while Aker BP will become a significantly larger company in all aspects that matter.

Before we integrate the two companies, however, we have to follow a certain procedure, and we are now in the process of preparing formal documents for the transaction which will be distributed to shareholders for approval at the respective general meetings. In parallel, we have initiated a process of obtaining approvals from relevant authorities, and if everything goes according to plan, we aim to complete the transaction by the end of June.

We are looking forward to sharing more information about this exciting transaction and the combined company in due course, but for now, let's focus on Aker BP as it is today and let me start with our operational performance.

This slide summarizes the key performance indicators for 2021, and I'll come back to production and emissions in a minute while David will cover the cost side in his financial review. But first, safety. I'm very pleased that we had no process safety or other serious incidents in 2021. When we look at the TRIF indicator, however, which also measures serious with less – which also measure less serious injuries, the number this year ended at 1.9.

This is a relatively low number compared to our closest peers, but it ended up from previous quarters. And we follow each and every incident in a systematic way to learn and improve, and let me be crystal clear, our ambition is zero incidents.

Now, let's move on to production. The Q4 production ended at 207,000 barrels a day, down from 210,000 barrels a day in Q3. The decrease was driven by technical issues at Skarv, which were resolved during the quarter, and projects activities at Alvheim, again, partly offset by higher production from the Valhall area. For the full year, production ended at 209,400 barrels a day, just shy of our guided range of 210,000 barrels per day to 220,000 barrels per day.

As we commented also last quarter, this was mainly driven by lower production than expected from the Ula area. We also had a few standalone events such as power outage from Edvard Grieg, which had negative impact on Ivar Aasen for parts of the third and fourth quarter, and we had chalk influx at a couple of wells in Valhall.

On the positive side, both Alvheim and Johan Sverdrup continued to beat our expectations in 2021. While we are, of course, not satisfied by missing our guidance, the asset teams deserve credit for the way challenges have been handled and mitigated during the year, and I have full confidence in our ability to deliver on our expectations going forward.

Now, let's turn to decarbonization. Our CO_2 emission intensity for 2021 ended at 4.8 kilograms per boe. This is lower than our targeted level of 5 kilograms per boe, which is very low compared to the industry at large. The slight increase from 2020 to 2021 was mainly driven by higher emissions due to power outages at Edvard Grieg impacting Ivar Aasen and process shutdowns at Valhall, in addition to lower production from the Ula area which, of course, are impacting production and not necessarily emissions.

In 2021, we continued our systematic approach to further reduce emissions from our operated fields and through our drilling alliances, focusing on a wide range of measures to improve energy efficiency and reduce methane emissions. At the start of the year, we set a target of reducing emissions by 10,000 tonnes of CO_2 equivalent and we have achieved more than twice this number in 2021 which, of course, is very positive.

We have also taken important steps to address our Scope 2 and Scope 3 emissions. The electrification of Ivar Aasen which will take place this year will eliminate almost all our Scope 2 emissions. When it comes to Scope 3, we are focusing on the things we can impact which are activities defined in the categories 1 to 9. Of the emissions we've been able to document in these categories, around half is related to supply ships and we have, therefore, engaged with shipowners and other oil and gas companies to optimize selling patterns and cargoes, and hence reduce overall fuel consumption.

More concretely, we have installed batteries on some vessels and will expand this to more vessels in 2021 to further reduce emissions. And in November, we entered into a joint technology project together with Eidesvik and Alma where we will explore the opportunity of installing fuel cells on existing PSVs, aiming to reduce the emissions significantly by using ammonia as fuel.

In sum, I'm very pleased with our progress in this area in 2021, and it's also encouraging to get recognition from the ESG rating agencies. As you can see on this slide and hot from the press, Aker BP has also today been recognized by CDP as Supplier Engagement Leader for our work to raise level of climate action across the value chain. This means that we are in the top 8% bracket of the participating companies.

Now, let us move over to another area with strong performance in 2021, which is project execution. In 2021, we continued to make good project – good progress on projects under development and in the execution phase. Starting with the latter, Ærfugl was delivered on schedule and budget in the fourth quarter, while Hod and Johan Sverdrup are fast approaching first oil this year.

Hod was initially planned to be put onstream in first quarter 2022, but it's currently waiting for the pipe layer Seven Vega to bring it over the finishing line, and the best estimates of first oil is now for May. As for Johan Sverdrup

Phase 2, it has progressed safely according to plan and costs. Hook-up and commissioning of the P2 platform, the second processing platform, made good progress and offshore installation is on schedule for March. All the five subsea well templates and most of the in-field pipelines and umbilicals have been installed.

Drilling of the new wells started in January with Deepsea Atlantic drilling rig, which brings us firmly on track for first oil in Q4 2022. And while the – and as we bring this project to completion, we replace them with new ones. We submit the three PDOs to the authorities in 2021 including Kobra East, Gekko and Frosk project in the Alvheim area, and Hanz in the Ivar Aasen area. All these project have robust economics with breakeven below $30 per barrel. And for those who are worried, rest assured there's plenty more where these came from and more on that shortly.

As we're entering a new year, I think it's a good time to step back and reflect on what Aker BP is and, more importantly, what it strives to become, which is the leading E&P company. Let's have a look at the Aker BP strategy.

After serving eight years as CEO in this company, I continue to be impressed by the organization's ability to create value for shareholders and the society at large. From a bird's-eye view, we have been dealt a good hand as a pure play E&P company on the Norwegian continental shelf, with a substantial portfolio of project to develop on the supportive Norwegian fiscal regime. But what is the secret sauce that has allowed us to deliver profitable growth for years and positioned us to do so for many years to come? Put differently, what has created and what will create value in Aker BP?

In addition to the obvious execution of several attractive M&A opportunities, I think Aker BP, as a company, has done the following three things exceptionally well: One, we've had the ability to turn around quickly in connection with M&A and otherwise, to develop and use technology to grasp opportunities that others has written off or even discarded altogether.

Two, we have developed and continue to fine-tune an alliance model with industry-leading partners, which strengthens the collaborative environment and ensure that we work with the best suppliers across the value chain to develop low-cost, low-carbon barrels. And three, we have maintained an entrepreneurial spirit in the organization and had supportive ownership that has allowed us to act countercyclically at attractive points in the cycle.

And as I take on my ninth year as CEO in the company, increasingly less handsome you can say, Kjetil, I can honestly say that the company has never been in a better shape than it is today, with bigger and more attractive project portfolio, a stronger organization, and financial robustness better than ever before. Coming back to the first point that has made the company what it is today, let's look at the digital strategy that has contributed heavily to transforming the company into what it currently is.

In Aker BP, we have always worked based on the thesis that it will not be possible to become an industry leader in the future by just using yesterday's methods and technologies, and that is why we have taken a very active role in both developing and adopting new technology into our workflows. On this basis, we have, over the course of several years, developed a digitalization strategy targeting full transformation of our key end-to-end processes. So with the risk of sounding a bit blunt, to us, digitalization is much more than just a buzzword.

But what does this actually mean specifically? By the end of this decade, we are aiming to be a fully digital and semi-automated oil and gas company. This includes a digital ecosystem where work processes are seamlessly integrated and with data flows without friction, with always up-to-date digital twins in the center. We have showcased some of these initiatives in different settings, including smart maintenance and automated well control to mention a few; however, let me make the case for a couple of more examples that demonstrate the potential we see in some of these initiatives.

The NOA Fulla development, which is our operated part of the NOAKA development, is being developed with a complete digital twin, enabling reduced costs, better reservoir understanding and modeling capabilities, and it represents the first step in developing the new standard software for efficient digital ways for collaboration and execution of projects. And let me give you a flavor of what kind of savings we're talking about.

We estimate that the reduction in engineering and constructions hours in the EPC phase of the NOA Fulla to be close to $100 million in CapEx on the project. In other words, such – in other projects such as Valhall NCP combined with King Lear should see a similar effect in a success case. The increase in resources that we announced for NOAKA last quarter was unlocked by collaborative well planning, which is a digitally-enabled process that allows us to optimize well path and drainage strategies, again, demonstrating how we leverage technology to maximize the value creation potential in the company.

Another example is the development of an underground ecosystem. And while this sound – may sound a bit scary, we have teamed up with the main leaders such as Halliburton. Amongst other things, this ecosystem has the potential to open up for a common structure of data tracking and scenario management across the subsurface community. The solution will enable all concept dependency to automatically be shared as the dynamics of reservoir model, data interpretation and field development designs are updated across data platforms, thus saving time, costs, and reducing risk.

This particular system is scheduled for a real-life test on drilling and well-related data in 2022, with further focus on developing the option for the whole subsurface going forward. A final example is the major strides we're taking in developing cutting-edge solution to drive production efficiency even higher. In 2021, we developed and adopted solutions to automate operations of well and critical equipment to prevent production losses. Combined with our push to move offshore work to onshore, this put up our operations at the world-class levels.

To summarize, we have come far and learned a lot, but as we move forward, we realize that we have – still have significant gaps to fill, and we will continue to work relentlessly towards our goals. In terms of transformation, another key area is the work we do with our suppliers, and we call this the alliance model.

We have talked about the alliance model many times before, but we still think it's an important story to tell. We established the alliance model to overcome the inefficiencies of the traditional project execution model of our industry where we saw that project optimization were fragmented, there were too many interfaces between customer and supplier, and incentives were not aligned between the participants in the process. The typical consequences are well known; poor flow of information, bad decision, a resulting slow progress, cost overruns, and low quality resulting in low operability.

One important purpose of the Aker BP alliance model is to remove the barriers between the supplier and the customer, and we do this by merging our own employees with those from the supplier into one single team, what we call the One Team spirit, with common goals and shared initiative as the basis for the One Team spirit.

Another purpose is to maximize the learning effect. A lot of the things we do are, in fact, repetitive tasks even if the oil and gas industry is famous for doing one-offs. And by keeping the alliance team stable from one project to next, we create an arena for continuous learning and improvement. This leads to improved performance over time both in terms of time, cost and, ultimately, quality.

A third important aspect of the alliance model is that it contribute to a long and strong relationship with our key suppliers built on commitment, trust and mutual benefit. This model has served us well so far and we have established alliances across all main disciplines. The alliances represent competence and capacity that is absolutely essential for our growth strategy going forward. And finally, sorry, the alliance model in a volatile world allows us stability and predictability both in terms of prices and capacity we would otherwise not have, which is extremely important, not at least in 2022.

And then when it comes to the evermore important topic of low carbon, we also have a strong story to tell. If we want to be the leading E&P company, we need to be leading on cost and we need to be leading on emissions. And I'm happy to see that we are amongst the very top players in the industry also in this regard. In fact, with rising carbon prices and the potential for oil buyers to demand lower carbon barrels, we consider this a future potential competitive advantage.

Decarbonization and minimizing our environmental footprint is one of our top strategic priorities. With our current plan initiatives, we are on track to achieve a 50% reduction of our gross Scope 1 emissions by 2030, and we expect to have net near zero gross emissions in 2050.

In addition, to continuously working to achieve gross emission reductions through efficiency improvements, electrification of additional assets, which we have talked about earlier, we're also evaluating a decarbonization strategy to achieve net zero in 2030. We will revert more on this topic in our Capital Market Update later this year.

And we don't stop here. In 2021, we strengthened our strategic priority to reduce Scope 3 emissions and continued to work with suppliers to set the reduction targets.

The PSV initiatives I just talked about is only one of many elements in this work, and this is pivotal in reaching our goal for minimizing emissions from our own activities on the NCS by choosing energy-efficient solutions and operations, as well as reducing emissions in our supply chain.

What this leaves us as a company is very much being on the offense when it comes to delivering low-cost, low-carbon barrels. But we have even bigger plans for the company with respect to growing the asset base and continue to explore for high-value barrels on the NCS. So let's make up the status of our resource base at the end of 2021.

Our 2P reserves were 802 million barrels at the year-end, down 40 million barrels from 2020. This is, of course, a net number made up of a drawdown of 76 million barrels, which were produced through the year and an addition of 36 million new barrels, which were new PDOs that we just talked about. This represents a 2P reserve replacement of just below 50%.

However, our 2C resources have increased by 10% to around 1 billion barrel. The main contributors on this side were the NOAKA and NCP/King Lear, which have both grown in size since the last update. And more on these projects shortly. This means that we ended the year with a resource base that was nearly 100 million barrels higher and that means that our combined resource replacement ratio, hence, was above 200%.

As most of you know, our single most important investment criteria is full-cycle breakeven below $30 per barrel. And the chart on the right shows how projects that are planned to be sanctioned by the end of 2022 are distributed on a breakeven curve. I think this effectively demonstrate the robustness of our project portfolio, which means that the barrels that will be converted into 2P resources, they represent high-value barrels, and this is exactly what our ambition is to deliver.

Coming back to the biggest project that will spur our growth going forward, let's now take a look at NOAKA and Valhall NCP/King Lear, respectively.

At NOAKA, we passed DG2 for the NOA Fulla where Aker BP is an operator in Q3 2021, with the Equinor-operated Krafla following suit in Q4 2021. This slide shows you the preliminary key financial metrics of the project. And to give you the headline figures, it's a 600 million barrel project with investment totaling approximately $10 billion, below $30 breakeven oil price and the first oil is scheduled for 2027.

Out of all the project I've worked with on developing and executing over the course of my career, this is probably the most flexible design I've ever seen. It allows for an efficient [indiscernible] (00:27:47) of additional discoveries in the future and it allows for the 12 reservoirs consisting of the existing NOAKA development to be efficiently drained. We see further upside potential in several surrounding structures and, again, we are on track to deliver the PDO by the end of 2022.

Bottom line, NOAKA is a project that will deliver substantial value for Aker BP and partners. It will also create significant ripple effects for the supplier industry as well as for the Norwegian society at large. And with power from shore, it will continue and contribute to further strengthening of our low-carbon profile.

Another project that will create significant value is the Valhall NCP/King Lear. And today, I'm pleased to announce that following an extensive strategic review of all potential development options for the King Lear since, of course, acquiring the asset from Equinor back in 2018, we have finally identified the solution with the highest value creation potential, namely including it into the Valhall NCP scope. And make no mistake; this solution dramatically improves profitability of the development compared to the other options we have looked at.

With King Lear included in the project scope, the gross resource estimates for the project grows to above 200 million barrels gross. Total investments are expected in the range of $4 billion to $5 billion. And once again, the project is well within our breakeven hurdle of $30 per barrel. Because the scope of the project has increased as compared to previously shown, first oil is scheduled for 2027, a bit later than previously indicated for Valhall NCP as a stand-alone basis. But at the same time, the value creation potential has greatly improved.

The design allows for potential extraction of additional gas volumes in the Valhall area, which will bring us even closer to delivering on the target of producing another 1 billion barrels from the Valhall field. I'm very excited about the opportunity posed by the Valhall NCP/King Lear, which will again create positive ripple effects for the supplier industry as well as for the Norwegian society at large. And since Valhall is already powered from shore, this project will also have a very low carbon footprint, which seems to be a recurring theme in our project portfolio.

So where does this leave us with respect to production going forward? When we add up the production profiles from all our existing assets and the planned development project, this is what our estimated production profile looks like today. We expect production to grow in the coming three years, driven by the Johan Sverdrup Phase 2, Hod, and other satellite developments. The next uplift comes in 2027 when we get NOAKA and NCP/King Lear on stream.

If we compare this profile to the one showed at our Capital Market Update last year, the 2026 number is now slightly lower. There are three main reasons for this.

Firstly, the Valhall NCP project was included in the 2026 numbers last year. Now, as I just mentioned, the project has grown in size with the inclusion of King Lear and production start has been moved to 2027. Secondly, and as we've previously announced, the Equinor-operated Garantiana project has been postponed by four years and is now expected to come on stream in 2029. And, thirdly, we have moved the anticipated start-up for Froskelår to 2028.

In 2028, Aker BP, on a stand-alone basis, expects to produce between 350,000 and 400,000 barrels per day. This is 80% higher than today and represent a cargo of around 9%.

Yeah. It's also worth mentioning that virtually all these growth projects come from project that are covered by the temporary tax system in Norway, and that they are highly profitable project with a life cycle breakeven of just below $30 per barrel. This production profile is entirely based on resources that we have already discovered. It means that any new discoveries could add to this picture, and that is definitely still on the agenda.

Aker BP is one of the most active explorer on the Norwegian continental shelf, which we still consider to be a highly attractive basin with significant potential for new discoveries. And when it comes to exploration, we have two main goals. The first goal is, of course, to find more oil and gas near existing infrastructure. Such discoveries typically have short lead times and extremely attractive economics, and contribute to high capital utilization and low unit cost at our hubs, thus contributing to a low-cost, low-carbon strategy.

Over time, we expect around 80% of our exploration wells to be in this category. And in our 2022 exploration program, the share is actually even higher, 12 of 13 wells are near-field targets.

The second goal is to find resources that are big enough for a new stand-alone field development. And the reason here is this activity has typically focused a lot on the Barents Sea. We completed our Barents campaign in 2021 and in 2022, we are, as I said, mainly focusing on near-field opportunities.

Before we turn to the actual exploration program, let me also mention that we are very pleased with the license award in the 2021 APA round. This round, which was announced in January, and as an active explorer, we need continuous turnover in our acreage portfolio. The APA round is an excellent opportunity in this regard. The new licenses represent great exploration opportunities that will strengthen our portfolio in existing core areas as well as new growth possibilities. And I would also like to thank our exploration team who, once again, have done an excellent job delivering highly successful applications.

And here is our 2022 exploration program, which, in my opinion, is the best program we've had for many years. In total, we are planning 13 exploration wells with a net unrisked volume to Aker BP of around 250 million barrels.

As you can see from this map, the wells are mostly located in our existing core areas, and 12 of the 13 wells are categorized as ILX or infrastructure-led. The only well that we defined as a growth opportunity is the Laushornet well, number one on this list, which is located near Garantiana in the northern part of the North Sea.

It's also worth noting that five of the wells are in the Skarv area. This is an area where we've made several commercial discoveries in the recent years, which form the basis for the Skarv Satellite project that we plan to sanction in 2022.

The purpose of these new exploration wells is to prove up additional resources, which can contribute to high capacity utilization at the Skarv FPSO into the next decade, and thus this makes Skarv another very attractive area of development for Aker BP.

Now, the next point on the agenda is the financial review. And I hand the word over to David.

David Torvik Tønne

Chief Financial Officer, Aker BP ASA

Thank you, Karl, and good morning, everyone. As today's presentation is an extended quarterly, I'm going to cover three main topics. First, a summary of our 2021 financial performance; secondly, a closer look into the details of the fourth quarter results; and thirdly and maybe most important, I will discuss our capital allocation priorities and investment profile for the coming years and end up with our specific guidance for 2022.

Please note, although my presentation is based on Aker BP as is and does not include Lundin Energy's portfolio, Aker BP's capital allocation framework and priorities will stand firm also post a potential closing of the Lundin acquisition.

The strong operational performance covered by Karl has also translated into a very strong financial performance in 2021. With stable production year-on-year and a very strong price environment, cash from operations was record high with $4.3 billion versus $2 billion in 2020. We also kept total spend below original guidance and combined, this led to a significant deleveraging of the balance sheet, ending the year with the net debt down over 50% and a leverage ratio of 0.3 times.

At the same time, we increased the distribution to shareholders. Total dividends paid was $487.5 million or $1.35 per share, up almost 15% from the year before. Furthermore, in December, in conjunction with the announcement of the proposed acquisition of Lundin Energy, we raised the dividend plan for 2022 to $1.90 per share, representing an increase of 40% from 2021.

A key priority for Aker BP has been and continues to be to ensure good cost control. And although it should be expected, I'm still very happy to say that we, in 2021, managed to keep total spend below guidance, especially given the issues observed both locally and globally across different supply chains.

Total spend ended up at almost $2.8 billion, which is roughly $180 million below the midpoint guidance for the year. And decomposing our total spend, on CapEx, guidance was $1.6 billion and we ended roughly $170 million below. This was driven by strong performance, in particular, on the drilling side on Ula and Alvheim and phasing of spend, in particular on Valhall and Sverdrup.

Abandonment spend of $200 million were spot-on plan, driven by good performance on plugging and abandonment on Valhall and slot recovery of old wells on Ula. Expex was $20 million below the midpoint guiding of $450 million, and this was mainly driven by lower field evaluation spend on NOAKA.

And lastly, operating expenditure was up roughly $13 million or 1.9% compared to the original plan. The main drivers for the increase were increases in power costs, cost of carbon taxes, and more well intervention work than originally planned. This was then offset by less spend on ordinary maintenance.

The 1.9% increase in OpEx is also directly transferable to our production cost per barrel key performance indicator. For 2021, the guidance range of $8.5 to $9 per barrel here shown on the right-hand side of the slide was directly linked to the guided production volumes of 210,000 to 220,000 barrels per day. Actual production cost ended at $9.2 for the full year, which means roughly $0.50 up per barrel pre-tax compared to the midpoint of the guidance.

As production ended just below 210,000 barrels per day, roughly $0.20 of the increase in the cost per barrel can be explained by lower volumes. Then, an additional $0.30 can be explained by increased cost of power, in particular on Valhall and Sverdrup, who are powered with electricity from shore.

For Q4 specifically, production cost ended at $10.1 per barrel. The increase from the third quarter was driven by lower produced volumes, high level of well work on Valhall, and the extreme electricity costs seen in Europe this winter. But remember, these power costs are, of course, also interlinked with the high gas prices seen in the same period and have, therefore, been more than compensated for by higher revenues.

When running six assets with a large activity set onshore and offshore, there are, of course, many underlying variances across different cost categories in any given year. The main objective is, however, for us to understand and manage the cost base to increase productivity and drive down underlying controllable costs, while we manage both operational and financial risk in a prudent manner. Going forward, this will continue to be a key priority for Aker BP.

Now, moving on to look at 2021 sales and price realization. Quarter-on-quarter, Aker BP's revenues increased by almost 20%, up to $1.85 billion. The increase between the quarter is mainly driven by this significant increase in gas prices. Total income for the year ended at $5.7 billion, up 90% from roughly $3 billion in 2020.

Realized crude prices versus average Brent is impacted, in particular, by timing of liftings, crude quality, and the performance of the marketing team. With stable production from a diversified portfolio, we saw limited effect of timing in 2021. And with a strong performing marketing team, we realized a crude price pretty much spot on to 2021-dated Brent average of $70.9 per barrel.

However, if we include gas, where our realized prices increased to almost $170 per barrel of oil equivalents in the fourth quarter, up 86%, the realized average hydrocarbon price was $96.4 per barrel of oil equivalents in the fourth quarter, 28% higher than the third quarter. For the full year, the average hydrocarbon price then ended at $72.7 per barrel of oil equivalents.

In 2021, gas has become an even more important part of our portfolio, strategically, given the role gas has obtained as a transition fuel; financially, as the increases in prices has made gas a larger part of our total revenues; but also operationally as we, over time, will increase our production of gas. Today, we have three hubs that produce most of our gas: Skarv, Alvheim, and Valhall, with Skarv being roughly 50%.

In 2021, gas was 18% of production. But in terms of revenues, gas increased its share from 12% in Q1 to 34% in Q4. Currently, 88% of our gas is sold on contracts that are linked to spot day ahead and the share of oil price-linked contracts will decrease from 12% down to less than 7% from April, and we also have the option to further reduce down to roughly 2% by October.

Going forward, although we will remain an oil-weighted E&P company, we have several new developments, which will add significant gas volumes to our portfolio. The Skarv Satellites is roughly two-thirds gas; on NOAKA, roughly one-third is gas, driven by the Krafla reservoir, in particular; and the large part of King Lear, which will be developed together with the new central platform at Valhall, is gas.

With that, I will move on to the second topic of my presentation, which is some extra color on the fourth quarter results and cash flow development. Subtracting production costs of $202 million and other operating expenses of $6 million from the record high total income, we get an EBITDAX of $1,641 billion in the quarter, up 22% from the third quarter. Exploration expenses amounted to $83 million, of which $31 million was field evaluation costs, a decrease from the third quarter as the full NOAKA project have now passed concept selection and cost related to this project is now capitalized.

We also had $33 million in dry well costs mainly related to the wells Mugnetind and Lyderhorn. Depreciation was $219 million or $11.5 per barrel. The decrease from the third quarter is mainly driven by Alvheim as the PDO of KEG also triggered a lifetime extension of the field.

In the quarter, we recorded an impairment of net $79 million. The main reason is a further revision of cost and production profiles for the Ula area. We have also expensed the previous capitalized cost for the Liatårnet wells. This noncash impairments have been somewhat offset by a partial reversal of the previous impairment booked on the Trell & Trine project, where concept selection passed in Q4 significant de-risking the project.

Profit before tax was then $1.2 billion, up 52% from the third quarter, and tax expenses amounted to $854 million, which means an effective tax rate for the quarter of approximately 70%. Net profit in the fourth quarter ended at $364 million or $1.01 per share, up 77% from the third quarter. Net profit for the full year ended at $851 million or $2.37 per share.

Let me also provide a few comments on the development in cash flows. Operating cash flow after working capital and taxes ended at $1,211 billion in the quarter. For the full year, the number was $4,282 billion. The fourth quarter was impacted by a working capital adjustment of roughly $235 million. The key driver was increased value of receivables related to gas sales late in the quarter due to the strong price increases. Net taxes paid in the quarter was $160 million, and this is the sum of two tax installments in total of $198 million offset by a refund of $38 million related to the final tax assessment for the fiscal year 2020.

Free cash flow ended at $706 million, a 16% increase from Q3. And free cash flow generated for the full year ended at $2.5 billion or $6.9 per share, up 451% from the year before. Dividends paid in the quarter was $150 million and $487.5 million for the year. We then ended the year with a cash balance of almost $2 billion, an increase of $547 million from the end of Q3 and an increase of $1.433 billion from the start of the year.

Then, a quick word on tax payments, it is again worth noting as explained at our third quarter presentation, that with the strong increase in oil and gas prices that we saw in late Q3 and Q4, the tax installments set in June and paid in the second half of 2021 were too low. This has had a positive impact on free cash flow generation and the cash balances at the end of Q4 of roughly $450 million. But this will then be balanced with equally higher payments in the first half of 2022 as shown on this slide. Still, even when adjusting for this delayed tax payment, it is notable that the adjusted 2021 free cash flow post-tax covered dividends paid in the year more than four times. And as for a reference, on this slide, you can also see the expected tax payment for the fiscal year 2022 at various oil price scenarios.

If we then take a quick look at the balance sheet at the end of the year, on the left-hand side, in addition to the increase in cash and cash equivalents, I want to highlight two other things. Other intangible assets decreased by $115 million. The decrease is mainly related to reclassification of the Equinor-operated Krafla part of the NOAKA project from exploration to assets under construction. This is a direct consequence of the project formally passing concept selection during the quarter.

And secondly, receivables and other assets increased by $154 million. The increase is mainly due to the receivables related to gas sales accruals, as mentioned when I talked about the changes in working capital. On the right-hand side of the balance sheet, the main changes are related to an increase in deferred tax and tax payables, and an increase in equity of $214 million. The latter is the profit for the period minus the dividends distributed.

It's now time to zoom out again as we move on to my third topic today, which is our capital allocation priorities. For many of you, our framework is well-known, and I want to be very clear. Aker BP's capital allocation framework stands firm. Our goal is to maximize long-term value creation. And to do this, we will ensure we have a sufficient financial capacity to withstand volatility and fund future investments. We will invest in profitable growth projects with a full life cycle breakeven below $30 for Brent using NPV10, and we will return the value created back to our shareholders through a sustainable and growing dividend.

The order of our three capital allocation priorities is not randomly selected. The first is our financial capacity. As we strongly believe that to be the leading E&P company of the future, the foundation is a strong balance sheet with significant financial flexibility that can withstand the volatility of the commodity markets as we go through the energy transition and that allows us to seize both organic and inorganic opportunities when they arise.

During 2021, we have reduced our net debt by over 50% from $3.4 billion to $1.6 billion, excluding leases. With the increase in prices leading to a higher EBITDAX, we have also deleveraged from 1.5 times EBITDAX to 0.3. Although the leverage ratio is a bit artificially low today, we believe in keeping it low also going forward with a clear goal of not exceeding 1.5 times over longer periods. Available liquidity have been increasing over the past few quarters. We have an undrawn revolving credit facility of $3.4 billion, in place with a supportive bank group of 17 banks. In addition, we have almost $2 billion in cash on account.

We have over several years also issued bonds in the US market to supplement our bank debt and add longer-dated maturities to our capital structure. Our first maturity is in 2025, and we only have $1 billion of debt that matures before 2029.

Aker BP's financial framework is also recognized by the credit rating agencies S&P, Moody's, and Fitch. We have investment-grade credit ratings with all three rating agencies, and all of them have a positive outlook or are currently reviewing Aker BP for an upgrade.

Our second capital allocation priority is investing in profitable growth. On the left-hand side of this slide, you see Aker BP's investment plans for the next seven years. On the right-hand side, you see the production profile that these investments will bring.

Our hurdle rate to sanction new project is, as mentioned several times today, a full life cycle breakeven below $30 Brent using a 10% discount rate. This means high returns and short payback times across most plausible oil price scenarios.

All the major investments on this graph are planned to be sanctioned by the end of this year, and thereby fall under the temporary fiscal regime in Norway. Both this regime and the proposed new tax regime in Norway is, to a large extent, what we call cash-based systems. This means that we get an immediate tax deduction of over 70% of the investment already in year one. And, in the temporary regime, the total tax deduction is 91.4% over six years.

The impact of this is that the net cash outflow is significantly reduced. This incentivizes investments in profitable projects that allows for investing in growth without stretching the balance sheet. And we strongly believe that investing in our project will create a lot of value for stakeholders, all stakeholders, and it provides profitable growth for our shareholders.

Now, a few comments on what the investment profile on the left includes: sanctioned projects, this is all projects where final investment decision have been made. That includes projects in the execution phase, such as Johan Sverdrup Phase 2 and Hod but also KEG and Frosk in the Alvheim area, and Hanz, which is a tieback to Ivar Aasen.

The second wedge is the non-sanctioned projects where final investment decision has not been made. This wedge includes our latest estimates for the new central platform project on Valhall, including King Lear. It includes the Skarv Satellites projects, and it includes Trell & Trine, which is another tieback to Alvheim. And lastly, non-sanctioned project also includes the initial estimates for the Equinor-operated Garantiana with CapEx mainly from 2027 and onwards, and production start after the timeline shown here on the slide.

The last wedge in the profile is the NOAKA project. This profile is Aker BP's net share of the estimated $10 billion gross investment that Karl covered earlier. The third element in our capital allocation framework is how we think about returning the value created.

Aker BP's distribution policy stands firm. A key principle is that dividends shall reflect the financial capacity through the cycle, considering the long-term financial outlook and the credit profile of the company. In line with increased value creation, our ambition is to provide a sustainable and growing dividend. The financial framework, including the dividend level, should be robust down to a $40 per barrel Brent oil price, and that oil prices above this level, the ambition is to grow dividends by a minimum of 5% per year.

The main vehicle for distributing value back to shareholders is cash dividends. But note that the policy also opens up for using buybacks to return value on top of the cash dividend. For 2022, the board of directors has proposed to pay a cash dividend of $1.90 per share. This is up roughly 40% from 2021. The planned 2022 dividend is to be paid in four quarterly installments, with the next payment already now in February.

Now to round off, with our capital allocation priorities fresh in mind, I will go spend a few minutes on summarizing the financial guidance for 2022. We have a very exciting year in front of us, with first oil on both Hod and Johan Sverdrup Phase 2. In addition, we have many important milestones throughout the year that will de-risk our project portfolio. The most important, of course, being the final investment decisions.

In 2022, we expect to produce between 210,000 and 220,000 barrels of oil equivalents per day. Roughly 20% of these volumes are expected to be gas. And of the total production, Johan Sverdrup is the biggest contributor with roughly 30% of production closely followed by Valhall. Ula is the smallest with less than 5%.

In terms of phasing, we start off in the lower end of the range and expect a small increase in production when the first wells on Hod comes on stream. Then in June, we have a month of turnarounds on both Johan Sverdrup and Valhall that likely brings the total production for the first half of the year slightly below 200,000 barrels per day.

In Q3, we expect a further ramp-up of production on Valhall and Hod. And in Q4, we expect Johan Sverdrup Phase 2 to come on stream. The ambition is then to leave 2022 with an exit rate of around 250,000 barrels per day. We expect average production cost of around $10 per barrel in 2022. This is the same level as Q4 2021, and the key driver for maintaining this cost level is the high activity across the asset base with start-up of both Hod and Johan Sverdrup Phase 2 but without getting a full year of production from them before 2023.

In addition, we have a high level of well maintenance activity on Valhall and, combined with the turnarounds, this drives relative maintenance cost. Lastly, we saw an increase in costs for environmental taxes and CO2 quotas in 2021. And we expect the trend combined with higher power prices to also continue into 2022.

Capital investments is expected at around $1.6 billion. This is the same level as the original guidance for 2021 but up from the actual spend last year. The reason is that roughly half of the underspend in 2021 is phasing into 2022. Roughly 40% of CapEx will be spent on Valhall with the completion of Hod and the FEED work on the new central platform and King Lear. Roughly 20% will be spent on Alvheim driven by the development of Frosk, KEG, and Trell & Trine. Another 20% will be spent on preparing NOAKA for final investment decision in Q4. And lastly, another 10% is linked to finalizing the Sverdrup Phase 2 project.

On exploration, we have a very exciting program that Karl has talked about with in total 13 wells. Total spend is expected around $400 million. And roughly two-thirds of this is well cost, while the rest is split between G&G, field evaluation, seismic costs, and area fees. Note that one big difference in 2022 compared to 2021 is that field evaluation costs are down roughly 75% as most projects has passed DG2 and are now capitalized. This means that although total expects is down from 2021, we are actually expecting to spend 40% more on actual exploration wells in 2022 compared to 2021.

Lastly, we expect to spend roughly $100 million on decommissioning in 2022. This is down 50% from 2021. Almost all of the spend is at Valhall with removal of old facilities and pre-P&A work, with the main part of the work being in the second and the fourth quarter. Then finally, needless to say, but I'll do it anyway. Please note that this guidance is for Aker BP as is. December 2021, we announced the proposed acquisition of Lundin. The transaction is subject to AGM and regulatory approvals, and we will provide more information on the combined entity in due time.

Now that concludes my presentation, and I will leave the word back to Karl for some concluding remarks before we, as normal, move on to the Q&A session. Thank you.

Karl Johnny Hersvik

Chief Executive Officer, Aker BP ASA

Thank you, David, for a very comprehensive walkthrough of both the 2021 and the Q4. Now, before we close the presentation and open for questions, let me revisit what I think are the key elements that define Aker BP. So, first of all, Aker BP is and will continue to be a pure play oil and gas company. Second, we have a high-quality asset base with low cost and low emissions and with significant upside potential from a near field exploration.

Thirdly, we are at the forefront when it comes to reshape this industry, both for our alliance model and our digitalization strategy. And fourth, we have a unique resource hopper, which will be turned into investment-ready project this year, all with highly attractive economics and all covered by a supportive tax regime, which will lift our production by almost 80% over the next seven years.

And last but not least, we have a strong financial platform, which allows us to fund this growth and to grow dividends along the way. And then hot off the press and recent as we've actually been sitting in this quarterly presentation, the government of Norway has approved the [ph] Kameleon/East Gekko (01:07:39) PDO, which means that this project is now live and we are continuing to mature it into the execution phase. So, well done to everybody who has worked on the KEG project. Now this concludes the presentation, and we are now ready to take questions.

QUESTION AND ANSWER SECTION

Operator: Thank you. [Operator Instructions] We'll now move to the first question from the phone. Please go ahead. Your line is open.

Teodor Sveen-Nilsen
Analyst, SpareBank 1 Markets AS

Q

Good morning, guys, and thanks for taking my questions. I have three questions. The first one is just general industry question. You have definitely been very good on cost discipline over the past few years. So, just wondered do you see any signs of cost increase for any of your suppliers?

Second question is on Fulla specifically and the write-down. Have you done any changes to the [indiscernible] (01:08:46)? And my third and last question is just on the exit rate. Did you say that there's exit rate of 250,000 barrels per day by 2022? That's all. Thanks.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Okay. So, on cost increase and thank you for very good questions. Yeah. We've, as David has outlined, I think, in every single quarterly presentation and as long as he's been CFO, focusing on cost discipline and maintaining a very focused approach to costs. We do see that there is some underlying cost increase in a few key areas. Many of them are actually related to more general inflation issues.

Most prominent is probably our rates but also a few commodities like steel prices. All the material prices are on the rise. We should not expect that Aker BP is completely immune to these cost increases, but I think it's important to say that we have been quite proactive in locking down rates and volumes as a part of our alliance model.

And then the question, will this continue, I think that's – is hard to say, but we do expect that there will be a very tight market for some of the essential supplies that are necessary in the oil and gas industry and particularly with those industries are overlapping other industry and [ph] just like (01:10:29), for example, on electricity production and the infrastructure.

On the Ula write-down, you want to do the technicals, David?

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. No. I can definitely do that, Teodor. So, it's mainly sort of phasing of production and costs, but there is some very minor also adjustments on the reserves.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

And then the final question was exit rate 2022.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. So, I think on production, I think I mentioned that. So, we are targeting roughly 250,000 barrels per day as an exit rate.

Teodor Sveen-Nilsen
Analyst, SpareBank 1 Markets AS

Q

Okay. Thank you.

Operator: We'll now move on to the next question. Please go ahead. Your line is open.

James Thompson
Analyst, JPMorgan Securities Plc

Q

Oh, hi. Good morning. It's James here from JPMorgan. Can you hear me, Karl and David?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Good morning, James.

James Thompson
Analyst, JPMorgan Securities Plc

Q

Good morning. Good morning. Just a couple of questions for me, really. Firstly, just in terms of the sort of medium-term plan on a stand-alone basis, I mean, I think one of the things that sort of caught my eye, I think, is really the CapEx phasing. It feels like CapEx is accelerating when production is roughly how we thought about it last year in terms of a big ramp in 2027, 2028. But that was also CapEx peaking sort of 2026 timeframe really, but it feels much more earlier than that. Can you sort of just talk a little bit about the phasing of the spend in the unsanctioned projects and why that might be quicker than previously?

And, secondly, just in terms of the digitalization piece, and I know that you sold your remaining stake in Cognite in the last couple of weeks actually. So, I just wondered whether or not that had any bearing on your digitalization plans. So...

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah. Thank you. You want to do the CapEx phasing question, David?

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. No, I can definitely do that. So, I think the short answer in terms of longer-term CapEx is that we have included the King Lear project as part of the NCP project, which means that there will be more CapEx in the medium term before that project, of course, comes on stream. And then, there is also CapEx related to the increased in reserves or the resources on the NOAKA development that we announced on our third quarter presentation. So I think that's what we're seeing. And, of course, it's, as you said, it's natural that you have a phase of CapEx before the production increases, of course, as you're well aware of.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah. And then, on Cognite, I mean, we have always been clear that we're not necessarily an investor in software companies, but we have participated in the development of Cognite as a company. And now that Cognite has matured, has a significant number of customers, mostly outside the oil and gas business, I think it's quite clear that we – and in line with our strategy – that we have now sold our share in the company and participated actually in securing another very attractive opportunity to Cognite, namely the collaboration with Saudi Aramco. And you should expect that this has no bearing at all on our digitalization strategy and our collaboration with the same companies.

We have, of course, had a strategy of, let's say, being a part of the early phase acceleration of these tech companies, also as a part of our ESG contribution, creating new employment opportunities in Norway as we grow from an oil and gas dominated economy through the energy transition.

James Thompson
Analyst, JPMorgan Securities Plc

Q

Okay. Brilliant. And just a final question for me, please, Karl, obviously, you've been taking advantage of the extremely robust gas price in Europe at this point in time, and rightly so. And you're clearly focusing some of your development plans more towards gas as well. But can you just maybe talk about kind of reservoir management of the producing assets at this point in time? I mean, should we expect kind of gas production overall to sort of fall as you – you can't sort of prioritize gas [indiscernible] (01:15:17) forever. So, I'm just wondering if you could talk to a little bit about the kind of gas management strategy as you seem to – over the next couple of quarters as you look to manage both the reservoir and obviously the very strong price environment for gas that is continuing this year.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

I think most companies, James, are assessing the depletion strategies at this point in time. I mean, historically, we have been thinking about gas as approximately 10% of the oil price in terms of valuation, right? But in Q4, I think it was – the average gas price in Europe was around $170 a barrel if you look at the equivalent oil prices. So, obviously, this is now being very much at the top of the, let's say, reservoir assessment, reservoir management, production management.

Short term, I think there are a couple of opportunities that we are assessing. So, the first one is the balance between gas production or rather gas export or gas injection at Skarv, which is probably the one that's most interesting to Aker BP. And then, of course, if we should continue to have these kind of gas prices going forward, both drilling of, I would say, gas pockets, possibly also gas caps, is going to be on the table. But for the time being, this is mostly about production management at Skarv and the balance of gas injection versus gas export.

James Thompson
Analyst, JPMorgan Securities Plc

Q

Brilliant. Thank you very much. I'll hand over.

Operator: We'll now move to the next question. Please go ahead. Your line is open.

Yoann Charenton
Analyst, Société Générale SA (UK)

Q

Yes. This is Yoann Charenton from Société Générale. Thank you, Karl and David, for hosting this presentation today. It's very much appreciated. Given Aker BP managed to achieve resource replacements of more than 200% last year without resorting to M&A, how would you justify a potentially expensive backfilling exercise by means of inorganic growth?

The second question – I will ask two more questions if you don't mind. The second question is, again, broadly speaking, how do you consider the investment criteria of $30 per barrel when making deals? In other words, what does this threshold entail for project that potentially don't make the cut in the [ph] back end (01:18:03) of assets acquired by the company?

And then the last question is focusing on what was disclosed today. And again, thank you for this. You have kindly shared with us the company's investment plan for the years 2022 to 2028 on slide 34. While the trend remains broadly similar to what you disclosed a year ago, the absolute amounts associated with the revised CapEx plan are significantly higher year-on-year. And meanwhile, if we look at the slide 35 and we focus on these [indiscernible] (01:18:42) curves, it has moved here as well.

So, appreciate you have commented on the largest scopes for Valhall NCP and NOAKA, but can you please provide a bit more color on this given [ph] you won (01:18:55) about inflation rate? Are you able to touch upon the assumptions you made on inflation?

And finally on this broader, let's say, investments equation, what [ph] share (01:19:05) of that program from 2022 to 2028 is set to fall within the temporary tax regime? Thank you.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah. Thank you for that. Well, we'll certainly do our best. When it comes to this resource replacement rates, as I mentioned in my walkthrough, the reserve replacement rate are roughly 50%. And then we have added resources predominantly at NOAKA and NCP/King Lear, which again has then brought the reserve replacement rate or the total resource replacement rate to around 200%. And obviously, as the NOAKA and NCP/King Lear are turned into PDO project by the end of this year, those resources will turn into reserves, which will mean that when we enter 2023, the reserve replacement ratio will be significant. Probably in excess of 500 million barrels will be added to our reserve base.

So, of course, you need to view this not on a year-by-year basis, but more on a rolling average type of basis as it will vary from year-to-year. So the way we think about this is that we basically work as best we can to maximize production and to maximize resources and reserves from the existing hopper. And then we think about inorganic growth as a way of adding to that hopper. So it doesn't necessarily mean that these two kind of column funnels of opportunities into Aker BP is necessarily competing for resources or capacity. So, we actually view them as two avenues that are largely disconnected.

And then the $30 breakeven, yeah, a couple of years ago, we had $35 breakeven. And then, as they will probably come back to, most of the new projects are now coming on stream will be PDOed by the end of 2022, which mean that they will be inside the new tax system. And as a result of that, we lower our investment threshold to $30. That means that there's a certain link between the threshold for organic investments and the tax system they are operating under.

So, it's not a simple question of basically using the same threshold for M&A activity as for organic investment opportunity. But what we are, of course, carefully consider is where to deploy our financial resources. So, if you now allude to the discussion we have had over the Lundin transaction announced to the end of last year, we basically thought about that as a very, very good combination of two of the best companies that was producing on the Norwegian continental shelf. And of course, we'll come back with significant more details as we move forward in that process. My expectations is that around the Capital Market Update in April, we'll be able to provide more detail on the M&A and organic side.

Now, let's move on to the CapEx and the phasing of CapEx, David. I've already covered the amount covered by the temporary tax issue.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. I think that's also one of the slides. So we've stated that roughly 80% of the investments profile will be covered by the temporary regime and in particular, the project, which is not [ph] I guess existing (01:23:13) Garantiana project as that's been moved out in time. And then there are, of course, also smaller infill drilling and so on, which is included in the non-sanction, which is not part of that.

When it comes to our assumptions on inflation, I don't think we want to disclose that because I think that's sort of part of our commercial discussions as well. But, of course, when sort of managing costs going forward, we will make sure to have the best estimates that we can going into the final investment decisions so that we encounter for potential inflation when we compare the business cases for the investments versus our investment thresholds.

Yoann Charenton
Analyst, Société Générale SA (UK)

Q

Thanks a lot both for addressing these questions.

Operator: We now move to the next question. Please go ahead. Your line is open.

Anders Holte
Analyst, Kepler Cheuvreux SA (Norway)

Q

Yeah. Good morning, guys. It's Anders Holte from Kepler Cheuvreux. Thanks for taking my questions. [ph] Guys (01:24:24) more connected to your guidance in terms of CapEx and also if you can give a bit more color on the operational cost guidance. You gave us some explanation why it's almost elevated this year, but just curious to hear what you think about operational cost per barrel in terms of a – yeah, longer time lines compared to your previous guidance.

And also just the CapEx profile that you show on page 34, you have previously shown that include – you have also shown that with your abandonment cost and also your exploration efforts going forward [ph] in time (01:25:08). So just wondering if you have an update on the exploration activity level we should expect from you, guys, and also the funding costs in a bit more longer time line. Thank you.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. Well, I can start on this and then Karl can fill in as well. So I think in terms of operating cost guidance for the year and to give some more color on that, I think there are couple of things that's driving the fact that we're keeping sort of $10 per barrel for 2022. As also mentioned in my in my presentation, it's sort of a high activity level across the asset base and in particular then also with Hod and Sverdrup Phase 2 coming on stream during the year and we won't get sort of full production from those fields before 2023.

And then we also have an ambitious programs with regards to the well work on Valhall during the year and combine then with the turnarounds on Sverdrup and Valhall. That means that we get, on a relative basis, slightly higher production cost per barrel.

And then, of course, the last point is – so the high cost of carbon and environmental taxes, which we expect to continue, and then the inflated power costs, which we assume, at some point, will go down, but we expect them to be quite high at least for the first half of the year.

And then, again, I think it's worth mentioning that we do have some sort of a natural hedge when it comes to electricity prices given the gas sales that we have which, of course, significantly outweighs the impact on production cost.

When it comes to the longer term, our ambition of driving production cost per barrel down below $7 has not changed. So there will always be specifics in any given year, also activity-driven which means that it will fluctuate, but the underlying addressable cost is something that we're focusing on driving down. And we do still see progress on, for example, the productivity on – of maintenance. And as I mentioned in my presentation, ordinary maintenance cost was actually down below our original expectation for the year, and partly the reason why the cost increase compared to original guidance was not higher.

When it comes to guidance on abandonment and exploration, you are correct. We typically have – provide the indications of that as well in our previous Capital Markets updates. But as this is not a Capital Markets update, we prioritized a bit. When it comes to abandonment, I can give color of that – on that. We expect roughly $100 million per year, on average, in abandonment expenditure through the plan periods. It will fluctuate a bit but $100 million this year and probably decreasing a bit in the mid-term before maybe increasing again at – towards the end of the period.

And when it comes to exploration spend, this is, of course, very much discretionary in the sense of we have a program for this year and we make commitments and then we can choose an exploration level. As indicated here, today, we will continue to be an active explorer on the continental shelf and we have strong believe in the opportunities. But we will, of course, think about sort of what a – the right level of exploration spend will be in the longer term once we have sort of gone through this year and have a firmer look on the total portfolio of the company.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah. And, like, the only addition to that is that going – historically, field evaluation costs has been a significant part of our expect – spend. And as now these project have – [ph] past (01:29:21) due and are moving into execution stage, we will get into a situation where much more of our exploration costs will be directly allocated to well and exploration activities, which means that you should expect a slight decrease from the current level.

Anders Holte
Analyst, Kepler Cheuvreux SA (Norway)

Q

Okay. Thank you. That's very clear. Thanks.

Operator: We'll now move to the next question. Please go ahead.

Q

Thanks. [ph] Guys (01:29:58), good morning. Thank you very much indeed for the presentation. And can I come back to the question on CapEx over the next six years, up to 2028, please? If I look at the CMD chart from beginning of last year, something in the CapEx up on slide 52 gets me to just over $11 billion. If I do the same on your slide today, slide 34, that comes to $16.7 billion, and that's $5.5 billion increase, excuse me, increase between those two charts.

Now, NOAKA seems to be about $2 billion. There's some deferral amount of 2021 into 2022 [indiscernible] (01:30:40) obviously [indiscernible] (01:30:42). But there's an extra $3 billion that isn't NOAKA. Could you perhaps just help me understand what that is referring to? Because if I compare it to your production profile as you've said, it looks pretty similar to what you've previously disclosed in the CMD. Can you help me understand what's happening, please?

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah, sure. I think the – I'm not going to comment on your specific estimations of the various elements here, but I think the key thing which has been added to the profile in additions to NOAKA, adjustments due to the resources, the estimates that we had done and sort of trying to extract more of resources in the area. It's – including King Lear, right? So, that was not part of that portfolio at the Capital Markets Day last year and that's adding production towards the end of the period, in 2028, in particular. I think that's the key driver.

Q

Okay. That's great. Thank you very much.

Operator: We'll now move to the next question. Please go ahead.

Al Stanton
Analyst, RBC Europe Ltd.

Q

Yes. Good morning. It's Al Stanton in Edinburgh. I think we're all sitting here with last year's slides versus this year's slides. So, I'm afraid it's another question about CapEx. I appreciate, David, that it's not a Capital Markets Day and we shouldn't have all the data today, but one of the questions I would like to ask about is you say 80% of the CapEx is targeted towards the temporary – investments [ph] in terms of (01:32:29) benefit from the temporary regime.

So, I'm wondering if you just snowplowed all your CapEx to ahead of first oil, because that's the defining issue, isn't it? You benefit from these tax breaks until first of oil and thereafter you don't. So, I'm wondering whether – looking at NOAKA, as an example, there's no CapEx in 2028, so I suppose that is the question. Is NOAKA, the $10 billion you're going to spend, is it totally all now prior to first oil so that you get the tax breaks or, as has been suggested, CapEx has increased?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah. Thank you, Al. This is probably – I mean when we're being this transparent, then you always get these comparables. So, first of all, I think the main increase is – as David touched on, in the previous question is related to the inclusion of King Lear, which have also, by the way, increased resources quite significantly, but that was the back end of the profile. [ph] Assets are peaking, gas (01:33:36) now moved from [ph] 26 to 27 (01:33:38). So, I think that's the main change.

And then whether or not there is, let's say, some of these wells which is predominantly the end of the CapEx profile, right, the construction is basically all done. So, whether some of these wells have actually been moved forward or not, I think it's – that's more of a, somewhat a reservoir drainage issue than a tax issue, to be honest.

On NOAKA, I think you'll find that that is the case, but it's mostly related to start-up of these wells as they come from very different reservoirs and we need a certain sequence in the start-up of the field in order to basically start up the facilities efficiently. So, this is much more technical in the way we're starting up the wells and moving that start-up well flow onshore rather than deploying it offshore.

Al Stanton
Analyst, RBC Europe Ltd.

Q

Okay. And then in a totally – sorry, totally unrelated question, you hinted at some decarbonization by 2030 and I was wondering if your attitude towards diversifying to renewable energy has changed at all given that or whether, as been suggested, higher gas prices as you're hedged against higher electricity price?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Again, you broke up a bit, Al. Could you repeat that question?

Al Stanton
Analyst, RBC Europe Ltd.

Q

Yes, sorry. I was just wondering if faced with higher electricity prices, is your hedge just higher gas prices or realizations or is there still perhaps a potential to look at renewables?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

So, the main hedge is, in fact, the higher gas prices, that they are correlated through the CO_2 prices with Norwegian electricity prices. The way we think about renewables right now, that yes, you could basically say that being an investor in renewables would be an interesting hedge against the higher electricity prices. But when you move to the opposite end of the scale, you actually have a different hedge, right, where you're actually not ending up in the short end of the stick, rather the long end of the stick.

So, at the – for the time being, we consider gas prices to be a relevant and sufficient hedge. And, of course, there's also a more tactical issue, whether we should, at some point in time, start to do PPAs, so longer-term contracts to hedge these prices. If you historically look at the variance of the electricity prices, such PPAs has not been value-accretive mechanisms to the consumers. So, for the time being, we prefer to be in the spot market and we prefer to look upon the variance between electricity prices on the cost side and gas prices on the income side as a sufficient hedge.

Al Stanton
Analyst, RBC Europe Ltd.

Q

Cool. Very clear. Thank you.

Operator: There are no further questions on the phone at this time.

Kjetil Bakken

Vice President-Corporate Finance & Investor Relations, Aker BP ASA

Okay. I don't think we have received any questions on the e-mail either, so I guess that means that we are finished. So, on behalf of the company, I would like to thank you all for participating. And if you have any follow-up questions, please don't hesitate to contact us in the Investor Relations Department. Thank you, all.