Operator: Ladies and gentlemen, good day, and welcome to the Antelopus Selan Energy Ltd. Q2 FY25 earnings conference call, hosted by Equirus Securities Private Limited. As a reminder, all participant lines will be in listen-only mode, and there will be an opportunity for you to ask questions after the presentation concludes. Should you need assistance during this conference call, please signal the operator by pressing star and then zero on your touchtone phone. Please note that this conference is being recorded. I now hand the conference over to Ms. Khushbu Balani from Equirus Securities Private Limited. Thank you, and over to you, ma'am.

Khushbu Balani – Equirus Securities: Thank you, Sagar. Good evening {? every- ?}one, and thank you for joining us. Also, thanks to Antelopus management for giving Equirus the opportunity to host the call. We have with us from Antelopus Selan Energy Ltd. Mr. Suniti Bhat, MD and CEO; Mr. Sivakumar, Director and COO; and Mr. Rajiv Tirupati, the CFO of the company. I would request Suniti to give his opening remarks on the quarterly performance and the outlook for the industry. Thank you, and over to you, sir.

Suniti Bhat – MD & CEO: Thank you, Khushbu, and thank you very much for joining our first investor call. It is one step in the outreach that we had been promising our investors for some time. We have finally managed to have an investor call, and we promise to keep it a regular occurrence at the end of quarterly board meetings, mostly on the same day. We will also be very happy to hear any feedback you have on these calls and our investor packs.

The idea of these packs and these calls is always to get you up to speed on what we are thinking, what we have done, and how we see this business going forward. It is to create more transparency around the information that we have about our business for all our stakeholders as we move forward.

With that said, I want to take a step back and explain how we look at the business, how we see ourselves growing over the next three years, which we call the short term, and then focus a little on this quarter's numbers and results, which Rajiv can go through in detail.

I want to start by saying that, since you must already have looked at our packs uploaded on the stock exchange website, we have some very good news. We had already started by saying that we had finally signed the RSCs, or revenue-sharing contracts, with the Government of India—two large ones, one in eastern India in onshore KG and one on the west coast, which is our backyard, the Cambay Basin.

These were substantially larger contract areas compared with the contract areas that used to be offered in the previous bid rounds. Finally, those contracts are official. I think we signed them on October 22. We have received those contracts. That has really invigorated the team to look for further growth opportunities as we move forward.

If I take a step back and look at what has happened in the growth of Antelopus over the last three years, I want to look at it through the lens of production growth, the lens of putting capital into the business, and the lens of maintaining EBITDA despite having seen both a downcycle and an upcycle in commodity prices. I also want to look at how we see ourselves building on what we did over the last few years, learning from it, and carrying that into the next three years, probably creating a

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company that reaches 5,000 barrels of flowing production over the next two to three years.

In fiscal year 2023, we had average production of around 511 barrels. Through a consistent understanding of our resource and reserve base, trying to exploit it, and deploying capital into projects, we ramped it up to 740 in 2024. The 740 became around 1,200 in 2025. Last year, we were at around 1,355. We are hoping that this year we will exit at around 2,500, which is the guidance. We are reasonably sure that we should be able to deliver on our promise to you of ramping up to 2,500 barrels of oil-equivalent production from our portfolio.

Our thought process has been simple: your resource is what is underground. We try to focus, with what I call a world-class technical team, on understanding the resource and unlocking it. While doing that, we generate surplus cash and have consistently been reinvesting the surplus cash into the business to grow it further. At the same time, we are creating a portfolio of opportunities for all our stakeholders within the Antelopus portfolio of assets, which will help us grow manifold over the next 5-10 years.

While doing so, we have remained a debt-free company that is growth-focused and has shown year-on-year growth and growth potential. We learn from things that work and from things that do not work as well, and we are nimble enough to keep changing our strategic focus as geopolitics in our industry changes or will change.

If I look at the exit rates, I have just discussed the average numbers. In fiscal year 2024, we exited the year at around 982 barrels. The next year, we exited at around 1,200 barrels, which went up to 1,758 barrels. We are hoping that it will go to 2,500 barrels this year, then around 3,500 barrels next year, and thereafter 5,000 barrels. We have some ideas about what it will be beyond 2029. We will share those numbers with you once we understand our onshore KG assets much better, so we should be able to give you much better news as we move forward.

While doing this, we started by spending around 51 crores of capital in 2023. Then we went to 160 crores. Again, we went to 87 crores and then 220 crores, and we are hoping to spend 250 crores this year. The idea is that we are also understanding and learning fiscal discipline as a group. As we go through this, we are learning that we are able to spend money, get it back within a year to a year and a half, deploy it again while it generates much more cash, and then deploy it again, hopefully giving you a return on equity that is much better than that of our peer group in this country.

While doing this, we are also keeping a strong focus on the EBITDA margin that we generate because unless we keep our costs under control, we can go on a growth path while continuing to erode our margins, and that does not help either. You can see that our EBITDA margins have historically stayed around the 50% mark, even during periods of low oil prices. Currently, they are much better. I think last year's EBITDA margin was around 58%. We expect this to be substantially better this year, largely because commodity prices are good, but also because we have maintained fiscal discipline. Hopefully, Rajiv will comment on this, but I think the EBITDA margin should be around the 70% mark, if I am not mistaken.

While this is happening from a strategic perspective, we are also trying to define our focus. Rather than focusing on everything in our portfolio, which would dilute the outcomes, we start focusing on one or two frontier areas every year or every couple of years.

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Over the last few years, there has been a major focus on the Cambay Basin and the Bakrol and Karjisan assets, which are currently the backbone of that basin for us. Then we started understanding the Assam–Arakan Basin through our Duarmara drilling. That gave us some interesting results. What we thought was gas appears to be oil. We also started getting some KG production.

As we move through the remaining part of this year and the next two years, we think that, given the portfolio we have developed in the KG Basin, a lot of our strategic focus and thinking will shift to onshore KG. We think that the core assets of the Cambay Basin, including Bakrol, are in what I call factory mode. We understand them reasonably well, and we are much more comfortable running a multiyear drilling program in our Bakrol and Karjisan fields.

We think those fields will continue to provide a solid foundation for us and will continue generating healthy profits and cash flow for our further growth over the next few years. They will also provide the seed money we need to leapfrog into unlocking substantially larger reserve bases in KG and, if everything goes well, offshore as well over the next few years.

At an operational level, we have just completed the 10-well drilling campaign in Bakrol. The drilling is complete, and the hydrofracking is finished. There were some operational delays in fracking, primarily due to supply chain constraints related to what is happening in the world, but that is all sorted now. We have started to see the full impact of the fracking and the 10 wells in Bakrol.

Bakrol itself had October average production of around 950 barrels of oil equivalent or more. That is very good and is in line with what we thought Bakrol would deliver. More importantly, it is telling us that Bakrol is one of the fields where, if you continue drilling wells, it will continue giving you production increases. Perhaps one or two wells every year will go toward offsetting the decline, while the rest will add to incremental production. Therefore, Bakrol will be a backbone for at least the next three to four years in terms of generating net revenues.

At Karjisan, the rig is currently drilling wells. It has already drilled two wells, which look very interesting on the logs. Hopefully, we will perforate one of the first wells over the next week and start seeing some results. From the way it looks, Karjisan is opening up areas toward the western and northwest frontiers of the field. We will continue pushing this frontier. Hopefully, we will be able to complete all seven wells that we planned to drill in Karjisan during this fiscal year itself.

That should give us a reasonably substantial boost in production as we move through the remaining part of the year and enter the next year. As we enter next year, hopefully by then the rig will be ready to start drilling Bakrol again and some of the other fields in the Cambay Basin.

Moving to our third operating field, Cambay itself, this is an optionality field for us. We want to drill one to two wells this year. Depending on whether they indicate oil or gas, we will decide what to do next year with the field. It is a large field, which is why we like it from an optionality perspective—it covers 160 square kilometers.

One or two successful wells, or both successful wells, could mean that it becomes, if not equal to Bakrol, definitely as substantial as Bakrol in terms of its potential as we move forward. We should have the potential of the Cambay field itself by the end of this fiscal year. Then we can decide

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whether to keep our guidance unchanged or increase it.

The most interesting and exciting thing for us is that, in the big rounds that we won, we tried to increase our position in both onshore KG and Cambay. In Cambay, we managed to acquire a couple of fields next to Bakrol. I think {? Pasunia 1 and Pasunia 2 ?} are next to Bakrol, and we acquired them. We also reacquired Ognaj, which we had relinquished because it was part of a package. We will determine what to do with it.

It was our relinquished field, but we also acquired a field called {? Uba ?}, which is close to our Cambay field and is a small gas field. We think it has shown good potential and is similar to Karjisan in terms of sand quality, but we need to determine how much oil and gas it contains. We are excited about the Cambay component because we already have operations there, so it should not take us long to start production from these Cambay discoveries.

In KG, we have added seven new discoveries to our portfolio. Therefore, we have around nine new fields in KG. Only one of them is producing, which is {? Mukamal ?}. However, some of these fields in KG are substantially large. Fields such as {? Bantulmilli ?} and {? Vadali ?} are there. I still need to learn how to pronounce the names, but what I do know is that we are trying to understand them.

We must definitely be among the top three acreage holders in onshore KG as of today. Over the next year or so, we will formulate an overall exploitation plan for KG. There will be a short-term exploitation plan that will look at existing wells and seek some opportunistic early production from the KG discoveries. [cut off]

Suniti: The long-term plan would be similar to what we did in Bakrol. We will bring in a rig, drill a couple of wells across the portfolio there, and then de-risk it. To put it in context, onshore KG potentially has a larger reserve base than the offshore portfolio we have today. If it works, we have a large enough portfolio to unlock production over the next 4 to 5 years.

[pause] The remaining point is that this quarter compared with last quarter has been flat. If anything, production is slightly lower than last quarter. This was primarily due to Karjisan, which we knew would start declining, while Bakrol took a little longer to complete and frac. Bakrol has increased and Karjisan has declined.

However, that is a temporary blip this quarter because the rig is back in Karjisan. With seven wells coming in there, we should start seeing a large uptick in production. In fact, October production itself is around 2,000 barrels of oil equivalent, which is the production across the portfolio for the month. With seven more wells to add to the portfolio, and if we get some good results from the Cambay drilling this year, we are very confident about a 2,500-barrel exit as we move through this year.

We are still evaluating {? Doarmara ?}. We are taking an integrated view and looking at the old and new wells together. What I can add is that, twice so far, we have gone back into the well and reswabbed the {? CS-1 ?} zone, and each time we have obtained oil from the well.

We are now trying to determine our next step for a potential oil development. Fracking or not fracking is not straightforward because it is difficult to organize fracking in Assam. We are putting

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together a full plan. We will then discuss it with our joint venture partner and hopefully determine the next step for {? Doarmara ?}.

As far as gas development in {? Doarmara ?} is concerned, I think the transportation issues will take their own time. We are going to focus on whether we can monetize the oil quickly and start getting returns from {? Doarmara ?} itself.

That summarizes where we are. I will now hand over to Rajiv to tell us a little more about the numbers for this quarter compared with the previous quarter, after which we can open the floor for questions. Thank you.

Rajiv: Thank you, Suniti. Good evening, everyone, and thank you for joining our first investor call. Let me now take you through the numbers, starting with the P&L.

Our realized oil price averaged $88.2 per barrel in Q2, against $95.3 per barrel in Q1. It moved sharply within the quarter. We realized about $76 in July, $84 in August, and around $100 or more in September.

Gas realizations, which move in line with oil prices, also fell from $10.33 per MMBtu, which was our average realization in Q1, to $8.84 per MMBtu, which was our average realization in Q2. The rupee was broadly stable at about 83 to the dollar. Volumes, on the other hand, remained flat, as Suniti mentioned.

To sum it up, revenue from operations stood at around 121.7 crores. Total income, including other income, was 127.2 crores. EBITDA was 90 crores, almost three times what we reported in Q2 last year, with a margin of about 71%.

For clarity, I would like to add that, in this quarter, our other income includes a one-off refund of 6.5 crores, which we had also mentioned in the presentation for the last quarter. We have now realized that amount in cash. Even if we exclude it, EBITDA was about 83 crores, which takes the margin to about 69%.

On the cost side, our opex and handling costs came down to 6.1 crores from 7.5 crores in Q1. Royalty and cess remained stable at around 16% of revenue, totaling approximately 20.5 crores. Because they move along with the price, they cushion our margins when the oil price falls.

Depreciation rose to 13.2 crores as the new Bakrol wells came into production.

To sum it up, net profit for the quarter stood at 57.3 crores, which is nearly five times the 11.8 crores reported in Q2 last year.

Our first-half sales averaged about 1,700 BOEPD, generating revenue of around 254.8 crores, EBITDA of around 180 crores, and net profit of around 112 crores.

Moving on to the balance sheet, as of September 30, shareholders' equity currently stands at around 780 crores. We have no borrowings. We hold roughly 100 crores in cash and bank balances and liquid investments.

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The balance sheet remains debt-free, so we continue to demonstrate strong cash generation, which helps us fund our drilling program through our own cash flows.

To sum it up, there are three key takeaways. First, oil prices swung during the quarter, but our volumes and margins held.

Second, our growth engine continues to run. The Bakrol campaign is complete, Karjisan drilling is ahead of plan, and October production is already about 1,950 BOEPD.

The third is what Suniti updated us on regarding {? DSF-II ?}. It gives us a second growth hub in KG, in addition to the Cambay barrels that add to our cash flows.

Therefore, we remain confident and on track for a 2,500-barrel oil-equivalent exit this year. We are building toward a 5,000-barrel business by FY29, with fiscal discipline remaining one of our key focus areas.

Thank you for your time. For any follow-up, you can reach out to our investor relations team at our investor email ID. We are now happy to take your questions.

Operator: Thank you very much. We will now begin the question-and-answer session. Anyone who wishes to ask a question may press star and then one on their touchtone phone. If you wish to remove yourself from the question queue, you may press star and two. Participants are requested to use handsets while asking a question. Ladies and gentlemen, we will wait for a moment while the question queue assembles. Again, to register for a question, you may press star and one.

Rajiv: Yes, we can hear you, Raman.

Raman: Sir, I have a few questions. First of all, congratulations on a very good set of numbers and a very strong quarter.

Starting with the margin aspect, on a quarter-on-quarter basis, despite the decline in average crude prices, our margins have improved drastically. When I look at it on a year-on-year basis as well, our operating expenses did not increase despite production and revenue increasing by 15%. Going forward, are operating expenses expected to remain the same, and can you guide us on whether we will operate at the same margins in the coming quarters?

Suniti: I think there are two parts to it. I will try to address it, and whatever I cannot address, I would like Rajiv {? follow up to ?} add to it.

One thing we have been saying consistently to all of you is that a lot of our costs are fixed and we have a good handle on them. The way we have structured ourselves, we are a company that is poised for growth. Therefore, whenever production increases, as we have said repeatedly, the incremental barrel cost is lower than our base barrel cost because our fixed costs start getting distributed over larger volumes.

You will start seeing the impact that you are seeing now. How long will it continue? We hope for a long time, in terms of cost efficiency and fiscal discipline.

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As far as margins are concerned, cost is one part of the margin. The second component for us will always be the oil price. We have no control over the oil price. The higher it is, mostly after royalty and cess, the more it flows into our bottom line.

As for costs, what we have said is that every incremental barrel, at least in Cambay, will cost less than the previous barrel because fixed costs start getting distributed. We will start getting a good understanding of KG as well. Rajiv, would you like to add something?

Rajiv: No, I think you have covered it well. Raman, in addition to what Suniti mentioned, he was right that fixed costs contribute around 70% to 75% of our cost base. If you look back at our numbers, this is the cost that has remained stable over the last couple of years.

In addition, there is another item, royalty and cess, which contributes around 15% to 16%. That moves along with the oil price we realize.

As Suniti said, we are well positioned to ramp up our operations at almost a similar cost base in the Cambay Basin. Having said that, if we are opening up a new front, you must appreciate that there are certain establishment costs that we take into consideration, especially in KG.

You may see the numbers increase, but not drastically. Therefore, the flow-through to our margins will remain resilient.

Raman: Can we expect this margin to continue at more than 65% for the whole year?

Rajiv: Our endeavor is to maintain those numbers. [cut off]

Raman: [overlap] Okay, understood, sir.

Rajiv: We will try our best to keep the numbers in line.

Raman: Yes. My second question is with respect to Karjisan. We are planning to drill seven wells by April 2024, and you also mentioned that two wells will be drilled by Q4. How much incremental revenue are we expecting from this region?

Suniti: I think there are two aspects to it. Let me clarify.

In Karjisan, we are planning to drill around seven wells. Two wells have already been drilled, but they have not come into production yet. We expect to start some production from them over the next 5 to 10 days as we move forward. We expect to complete this seven-well drilling campaign during this fiscal year itself.

Karjisan is an interesting field for us because it has the best fiscal terms in our portfolio as of today. It has concessional cess and royalty rates because it is still in its primary term under the production-sharing contract.

Karjisan will therefore have a disproportionately positive impact on our P&L. In fact, every barrel from Karjisan adds twice the value of a barrel from Bakrol. It is built into the 2,500-barrel exit as far as we are concerned. Watch this space in terms of how the growth develops. Karjisan wells tend to be very good. We are hoping for a good, positive and pleasant surprise from this campaign.

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The two wells I was referring to are in the Cambay field, toward the southern part of our Cambay Basin. We are also planning to drill them during this fiscal year, probably in late February or early March. Those two wells will tell us whether it is an oil play or a gas play and how large the play is.

Even if one of them works, the Cambay field itself could be as large as Bakrol, if not larger. It is still early days, but those two wells will be drilled. This is a 50% joint venture between us and {? Synergia ?}. We need {? Synergia ?} to be aligned with the way we are looking at drilling the wells and everything else, but this is a growth optionality that we have in front of us today.

Raman: Sir, if my understanding is correct, during this quarter, as of October, Bakrol production was around 750 barrels of oil per day. Are you saying that these two Bakrol wells will deliver more than that—around 1,500 barrels per day, or twice Bakrol's capacity?

Suniti: Raman, no, that is not what I said. Bakrol is already flowing. I think Bakrol is producing around 950-odd barrels of oil equivalent per day.

By the end of this fiscal year, we should have all seven Karjisan wells in production. With all seven new wells, or seven or more new wells, from Karjisan added to production, we should reach at least a 2,500-barrel oil-equivalent exit this year. This is based on our current production levels from the other fields. [cut off]

Management: The new Karjisan wells will definitely come, and we will build on Karjisan as we move toward 2,500-plus barrels of production.

It is the Cambay field, not the Cambay Basin, that is toward the south near Khambhat, where we are 50% partners. We are hoping to drill one to two optionality wells there as part of our farm-in agreement with our partner. If they work, then in the future—not this year, but perhaps next year or the year after—the Cambay field itself could potentially become as large as Bakrol, if not larger.

The details of how large it could become will depend on those two wells and their outcomes. If it works, this could probably help us deliver beyond 5,000 barrels as we move forward.

Raman: Understood, sir. Understood, sir. I have another follow-up regarding the other oilfield, onshore KG, which you mentioned as one of the promising portfolios.

You have added seven new fields to the onshore KG portfolio. How are you planning to ramp up the onshore KG Basin going forward? You also mentioned that the recovery with respect to onshore KG would be quicker and faster and that the incremental capex required would be manageable.

Management: Onshore KG is a little different from what we have traditionally seen in the Cambay Basin. We have acquired seven new fields, and we are excited because they are large fields. The resource base in these fields is larger than the offshore portfolio we have, so we are gaining access to a resource base in an onshore setting that we traditionally would have had to go offshore to access. That is the positive aspect.

KG is a high-pressure, high-temperature basin, so the wells in KG will cost substantially more than wells in the Cambay Basin. On average, if I spend $1.5 million per well in the Cambay Basin, I estimate that I will spend around $10 million per well in KG, based on previous experience. We have

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not completed the full costing, but that is my estimate based on my history in the industry.

What we are now going to do is fully understand this resource base and then develop a strategy for deploying one rig across at least the first phase. You have seen how we operate. We do not acquire five rigs and start drilling randomly. We acquire a rig, drill a couple of wells, fine-tune our understanding, and then start opening up the purses for an aggressive drilling campaign in KG.

If KG works even 50% as well as Cambay has worked for us, it opens up significant production potential over the next 3 to 4 years. Whatever we may start exploiting and depleting in the Cambay Basin, KG will begin replenishing at a much faster pace. That is the KG story as of now.

We need to watch for KG announcements from us. The first thing you will see us announce at some point, hopefully not too far in the future, is a resource estimate for KG. We will tell all of you the resource estimate after we complete our analysis and obtain a third-party reserves estimate for this basin.

Raman: Will all this drilling, including all three basins mentioned earlier, be funded through internal accruals?

Management: It is too early to say. It will depend on our appetite to ramp up. We can fund any kind of growth through internal accruals, but that takes longer.

We will then have to decide how much debt, balance-sheet funding, or new capital raising we want to undertake, given the need, our understanding of the reservoirs, and how we want to deploy the capital. We will come back to you with answers on that, but as of today, we are not committing either way.

I know that a single-rig KG program will require substantially more capital to be deployed into the ground compared with what we see in the Cambay Basin. However, I also know that once we do it, we will have continuous production, so the revenues generated will also come faster and be an order of magnitude higher than what we currently obtain in the Cambay Basin.

Raman: Yes, but at least the production plan that you have for the next [cut off]

Management: So the 5,000 [cut off]

Raman: [inaudible] [cut off]

Management: The 5,000-barrel plan that you have includes a very subdued contribution from KG and the Cambay optionality.

Raman: Okay, understood. Understood, sir. Thank you. I will rejoin the queue.

Management: Thank you.

Operator: Thank you. The next question comes from the line of Shubham Jain with Niveshaay.

Shubham Jain – Niveshaay: Hello?

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Management: Yes.

Shubham Jain – Niveshaay: I hope I am audible?

Management: You are audible now. We briefly lost you, Shubham, but yes. Could you tell us your name again? We could not hear you.

Shubham Jain – Niveshaay: My name is Shubham Jain from Niveshaay. Congratulations, first, on your maiden call and on a fantastic set of numbers. I had two questions. [cut off]

Operator: Sorry to interrupt, sir. Shubham, we lost your audio once again in between.

Shubham Jain – Niveshaay: Can you hear me now?

Operator: Yes, sir. This is much better.

Management: Yes, you are audible now.

Shubham Jain – Niveshaay: I wanted to understand two points. One was related to costs. When we last interacted, you explained that the structure was broadly 1,500 per barrel of oil equivalent, and we are trending far lower than that.

I wanted to understand how this is divided between fixed costs, variable costs, and royalty, and what number this should trend toward as we ramp up both our Cambay onshore portfolio and Bakrol.

Management: I think we lost a substantial part of your question, but the part we could hear was that you were asking how we would maintain our cost structure.

Last time, we discussed that we were at 1,500 per barrel and wanted to reach 1,500 barrels of production. Now that we are targeting much higher numbers, how will this affect the cost base? Was that the question in the context of Cambay generally?

Shubham Jain – Niveshaay: Correct. [cut off]

Management: Please go ahead.

Shubham Jain – Niveshaay: Correct. We are trending below the 1,500-per-barrel-of-oil-equivalent number that we initially guided for. How will this trend, since it appears to be providing us with significant operating leverage?

Management: Shubham, you are right about the trend you are seeing. However, as we discussed in our last conversation, the bulk of our costs are fixed, and you are seeing operating leverage play out. The same cost base is being spread over a larger production base.

The second point is that the fiscal terms of Karjisan are much better than those of our other Cambay blocks. The statutory levies in Bakrol or Cambay are around 30% of our top line, whereas in Karjisan they are less than {? one-third of that ?}.

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Given that Karjisan is contributing significantly to our production base, you now see those numbers averaging around 15% to 16% of our top line as statutory levies. That is one reason why you are seeing our entire operational cost base trending around 35 to 40 crores.

If you look at our operating expenses, they include opex, handling and processing charges, and other expenses. They have been broadly flat over the last couple of years. That is because, as Suniti mentioned, we staffed up for a larger operation.

That is also one reason why we are trying to accumulate assets: it gives us the ability to spread our costs over a larger base. You will definitely see this operating leverage play out in the coming quarters.

Management: Shubham, this was also a conscious decision we took a long time ago regarding how we built the organization and our execution capabilities, even when we started as a 400-barrel company.

The idea was that we knew we needed the right skill sets and the right kind of people to position us for growth. In my view, 1,500, 2,000, or even 5,000 barrels is only an intermediate number. We hope to become a much larger player in the energy landscape of this country. We believe we already have the team in place that will take us there.

Shubham Jain – Niveshaay: Understood. As a follow-up, I understand that the royalty mix will change and that this 16% to 17% will start increasing as we develop Bakrol and onshore KG. However, regarding fixed costs, handling costs, and other operating expenses, is it fair to assume that these will grow much more slowly than our volumes?

Management: You are right regarding the opex component, as I answered in my previous response.

Regarding handling and processing charges, our operations work as follows: the handling and processing charges are paid to a company such as ONGC, to which we send our oil sales through a tolling arrangement. We produce in our field, transport the oil by truck to an ONGC system, and from there it is sold onward to IOC. This is the model we operate in the Cambay Basin.

The costs are broadly fixed, although they are a combination of fixed and variable costs. The fixed costs are spread over a larger base as we toll through ONGC, while the incremental cost is only the variable cost, which is $1 to $1.5 for every barrel we produce.

You will see an increase on that front, specifically in the variable component, but the fixed costs will remain broadly flat. That is why I mentioned that operating leverage will start playing out as we ramp up. [line issue] That will be a completely new and different operation, in which you will see a temporary increase in operating expenses, but this will eventually be offset by the larger production base.

Management: In KG, we currently have very little infrastructure. Hopefully, we will bring KG to the same kind of cost structure, execution structure, and operating structure as our Cambay operation.

Once that is done, you will again see that we have to spend money and create a fixed-cost base initially, but as production ramps up substantially from there, the same operating leverage we are

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seeing in Cambay today will be repeated.

Shubham Jain – Niveshaay: Understood. My second question is regarding capex and how we see growth in FY28 and FY29 in terms of the mix we have built. A significant portion is coming from onshore KG and offshore. I wanted to understand the timelines and quantum of capex we are planning to reach these numbers, specifically for onshore and offshore.

Management: If you look at the chart we have, the 5,000-barrel forecast we are discussing is onshore. There is no offshore capital expenditure or production involved in the 5,000-barrel guidance we are giving you.

We are still treating offshore as an optionality that we will execute. However, in fiscal years 2028 and 2029, we will start focusing the time of the management and technical teams on it as a strategic priority. We think that, by that time, our understanding and maturity regarding the KG onshore Basin will be at the same level as our understanding of the Cambay Basin today.

For us, the Cambay Basin is now more like an operating mill. Therefore, we are getting our thinkers and technical teams to focus on the onshore KG Basin. If, in a year to a year and a half, we reach a position where these teams can start working through and identifying an opportunity set offshore, that is how we view the portfolio today.

This is not the production and capital expenditure that we are showing in the strategic focus areas. Even for the 3,000 and 5,000 barrels, we will determine how much capital is required at the appropriate time and give you full capital guidance as we prepare the field development plans for the regulators.

Shubham Jain – Niveshaay: Understood. That was helpful because I assumed the strategic focus was on production, but it appears to be on capex.

Management: No.

Shubham Jain – Niveshaay: No.

Management: It is strategic management focus on opening up the optionality for us.

Shubham Jain – Niveshaay: Understood. As a follow-up, across Cambay and KG, is it fair to say that we can reach approximately 7,000-plus barrels of oil equivalent per day in production?

Management: I am committing 5,000 to you as of today. Let us just

Shubham Jain – Niveshaay: Okay.

Management: understand KG a little better. We will discuss any changes to this guidance as we conduct these calls each quarter.

Shubham Jain – Niveshaay: Okay, done. Perfect. Thank you so much.

Management: You are welcome. Thank you.

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Operator: Thank you. Ladies and gentlemen, to ensure that management is able to address questions from all participants in the conference, we request you to limit yourself to two questions each and rejoin the queue for any further follow-up questions.

The next question comes from the line of Venkatesh Subramanian with LogicTree Consultants Private Limited. Please go ahead.

Venkatesh Subramanian – LogicTree Consultants Private Limited: Hi, Samit. Hi, Rajiv. Good evening. Thank you very much for hosting this call. I really like your interactive approach. It was very refreshing and very clear, with a lot of clarity.

I have two questions, as requested by the moderator. I want to understand the pricing formula. How do you actually fix the price for a customer? Is it based on the spot price, or is it an advance contract set 15 months, two months, or one month before? Is it pegged to the Brent crude price plus a discount or something similar? That is my first question.

My second question is: when you have this kind of formula in place and are preparing a three-, five-, or seven-year growth plan, what is the worst-case crude price that you use in your sensitivity analysis? What would be the blue-sky scenario over a five-year period, based on your experience? Could we use a range of $50 to $120, or what range should we use for our sensitivity analysis?

Management {? Samit ?}: Thank you, Venkatesh. I will let Rajiv answer the first question, and then I will give you my view on the second question. Rajiv, why do you not take the first question?

Rajiv: Hi, Venkatesh. Regarding the pricing formula, our contracts are pegged to an international crude oil marker. It depends on the contract because each contract has its own pricing mechanism.

However, it is safe to assume that across the Cambay Basin—meaning OLP, Tarapur, Karjisan, and Cambay taken together—we sell at approximately a 10% discount to Dated Brent.

Venkatesh Subramanian – LogicTree Consultants Private Limited: A 10% discount to?

Rajiv: Dated Brent.

Venkatesh Subramanian – LogicTree Consultants Private Limited: Okay, understood.

Rajiv: To add a small caveat, most of our sales are to Indian Oil, which is a public-sector buyer, but part of our volumes are also sold to private buyers, who constitute around 20% of our sales.

Recently, we have seen that their ability to purchase crude oil at higher prices is limited. We witnessed this over the last couple of quarters when crude oil started moving toward $100 per barrel. We are selling almost everything to Indian Oil at these prices, while some portion of our volumes is sold to private buyers. In order to manage our working capital, we end up selling to them at a slightly higher discount to Dated Brent.

Venkatesh Subramanian – LogicTree Consultants Private Limited: Okay. Is the Dated price an average?

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Rajiv: The price I mentioned in my opening remarks, Venkatesh, is the average price realization we achieved during the quarter, which was approximately $88 to $90 per barrel.

Venkatesh Subramanian – LogicTree Consultants Private Limited: Mm.

Rajiv: For Q2, if you look at the July, August, and September prices, they bottomed out around July and August before rising back to $100 in September. We saw a quarter-on-quarter decline of approximately 7% to 8% in our price realization compared with Q1.

To refresh your memory, we now understand that prices are above $110. However, if you look at July and August, they were trending around $75 and $85. We realized around those levels in July and August. September was the month in which we realized more than $100.

Management {? Samit ?}: Venkatesh, to build on that, this 10% discount to Dated Brent that Rajiv mentioned is not arbitrary for us.

The way it typically works is through different crude cuts. They examine our crude and determine the products that can be produced from it. This is done physically in a third-party laboratory. Based on the yields from our product, they compare it with a benchmark crude.

We continue to refer to Brent because it is globally the simplest benchmark to explain from a marketing perspective. We then determine the product mix that would be obtained from our crude. Depending on that product mix, the discount is calculated.

Therefore, it is not primarily a negotiated term. The only negotiation is about which crude most closely matches our crude—whether it is crude A, crude B, or crude C. To simplify it rather than get into the complexity, for your modeling purposes, you can take Brent less 10%. On average, that should provide sufficiently accurate numbers for your models. It is a fairly long and carefully considered process that determines the price of crude.

The key point is that our pricing is tied to an international benchmark. It is not controlled by the government or anyone else. Nobody mandates our price; the market determines it for us.

You could say that President Trump manages prices for practically everybody in the world today, [laughs] but apart from that, it is the market that drives the price.

The second point is a very tricky question. Rajiv and I have always maintained that, when we evaluate investments, the only thing we cannot predict or control in our business is the commodity price.

If, at $65 or $70, a project gives me a double-digit return and returns my cash within a year to a year and a half, it is a good project for me. If anything more happens, I am happy, but I also want to ensure that I get my cash back at an oil price of $50.

If I am losing money at an oil price of $50, I would think twice about executing that capital project. These are some of the basic rules we apply in our physical capital allocation, and they appear to have helped us.

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This is not arbitrary. It is something I have learned over the last 30-odd years in this industry. We cannot control the commodity price. As long as we get our money back within a shorter time frame, during which we have some certainty about prices, that is why the one to one-and-a-half-year period becomes important to us.

Venkatesh Subramanian – LogicTree Consultants Private Limited: That is very helpful, sir. I think the $50 to $60 range as the bottom range for breakeven and recovering your cash flows is very helpful.

Management {? Samit ?}: Yes.

Venkatesh Subramanian – LogicTree Consultants Private Limited: All right. Thank you very much.

Operator: Thank you. Ladies and gentlemen, we request all participants to limit themselves to one question each and rejoin the queue for further follow-up questions.

The next question comes from the line of Pawan Kumar with Ratnatraya Capital. Please go ahead.

Pawan Kumar – Ratnatraya Capital: Hi, team. I wanted to understand the potential of the Assam fields that we have. I understand that there is also a joint venture partner. Could you provide an idea of the capex per well, as you did in the Cambay Q&A, and compare it with the capex expected in the Cambay and KG Basins? What could the potential be there, what potential do you see, and by when can we scale it up? What is your overall expectation?

Management {? Samit ?}: This is regarding our Duarmara field. We have already drilled one well in that field, so we know what it typically costs to drill a well there. How much was it, Rajiv?

Rajiv: It was 70 crores, give or take.

Management {? Samit ?}: The well cost was around 70 crores, give or take. However, that well targeted three different reservoir zones at different depths in the basin.

We were looking at the Tipam 1, Tipam 2, and Tipam 3 reservoir zones. Actually, we were looking at Tipam 2 and Tipam 3 as gas-bearing zones. We saw definite indications of gas in Tipam 2 and some indications in Tipam 3. However, what we found was oil in Tipam 1, which we had not factored into our plans.

Our team is currently evaluating not only the well we drilled, the Duarmara 4 well, but also some old wells that Oil India drilled and that may be accessible. We want to determine how to access them safely. These are Duarmara 1 and Duarmara 2.

We are looking at a collective plan for entering Duarmara 1, 2, and 4, if possible, to understand the potential of the Tipam 1 zone. We are focusing on Tipam 1 rather than Tipam 2 and Tipam 3 because Tipam 1 is an oil zone and does not involve the same dependence on gas evacuation infrastructure out of Assam that gas does.

I can transport oil by truck, as you see us doing throughout the Cambay Basin. That is why we are asking what the potential for oil production from these wells is. It is still early days. All we know is that we have managed to circulate oil out through the wellbore twice, and we have seen oil come out both times.

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We are now evaluating whether we want to flow it or frac it to understand the potential. We will not make a decision based on one well; we will look at all three wells together.

The capital cost per well will be around 60 to 70 crores, even if I shorten the well and make it simpler by targeting only this zone. We hope to formulate a complete plan over the next 5 to 6 months regarding what to do with Duarmara. We will then provide you with a concise plan for Duarmara going forward.

We also have to take our partner's views into account. Wherever these are joint-venture operations, such as the Cambay fields or Duarmara, we have to bring everyone along. In a 100%-operated field, it is simply the management team making the decision about what to do.

Pawan Kumar – Ratnatraya Capital: Once the capex per well is incurred, is my understanding correct that opex would be almost the same across all the sites, or would it be very different?

Management {? Samit ?}: Opex is not fundamentally large in this case. It is not going to be drastic. There may be some Assam-related element because cost structures are fundamentally different in Assam compared with Gujarat, particularly for oil and gas operations.

However, opex will not be an order-of-magnitude figure like 70 crores. That is more of a capex issue, mainly because the wells are deeper. These are 3.5-kilometer wells, unlike the 1.5- to 1.6-kilometer wells that we drill in the Cambay Basin.

Pawan Kumar – Ratnatraya Capital: Understood. So would we be able to see a meaningful contribution only next year? Is that correct?

Management {? Samit ?}: Yes. The next fiscal year is when you would estimate anything meaningful from Duarmara, not this fiscal year.

This fiscal year, we are still examining what kind of oil we found. We know that it is light oil, but we need to determine how to extract it, how much is present, and what technology we may need to bring it out and sell it.

Pawan Kumar – Ratnatraya Capital: Understood. Thank you.

Management {? Samit ?}: All right, thank you.

Operator: Thank you. Our next question comes from the line of Manpreet Arora with The Northern Lights Wealth. Please go ahead.

Manpreet Arora – The Northern Lights Wealth: Thank you. I am following up on the previous participant's question about Duarmara. You mentioned that we found oil instead of gas, which you were not expecting, and that the decision is whether we want to flow the oil.

If we decide to flow it, would we be able to monetize it earlier than if we had found gas, because gas would also have required us to establish evacuation infrastructure? Is that the right way to think about it?

Management {? Samit ?}: In a simplified answer, yes, but I want to provide a little more context.

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Even in a gas system, we would have been able to develop a facility and monetize it relatively early, because gas can be transported through pipelines. The challenge with gas evacuation and monetization in Assam today—not only for us, but for many others—is that Assam is not yet connected to the national grid.

Therefore, even if you have the capacity to produce gas, not all the gas that Assam can produce gets sold in the market. As a result, you end up selling gas at a discount to APM prices in Assam today.

That is the situation, and connecting that grid to the national grid is not in our hands. There are many other developments taking place, including the Urja Ganga gas pipeline.

Gas in Assam is easy to monetize in terms of putting up a facility, but it has structural challenges regarding your ability to ramp up, even if your well has gas capacity. There are other players, including private players, in that field that [cut off]

Management: They are starting in the right distribution and production areas. Therefore, gas in Assam's vicinity, as of today, is delayed in terms of its revenue-generation capacity.

Oil is an interesting commodity because it does not require pipeline infrastructure. I can put oil into trucks, haul it across 300 kilometers, and sell it to a refinery somewhere. Therefore, oil gives us much more flexibility.

Oil infrastructure is also simpler and easier to execute and construct than gas infrastructure. That is why we see it the way we do today. If we find oil, the time from flowing sustainably to the surface to selling it will not be long. It will be a matter of months.

Gas is not always like that. Gas takes its own time because you need compressors and gas treatment packages. Oil infrastructure is much simpler.

Manpreet Arora – The Northern Lights Wealth: Thank you for that, sir. Just a clarification: regarding Duarmara, is it dependent on the Duliajan-Numaligarh pipeline, or is it a separate pipeline?

Management: It is entirely dependent on it. You have identified the exact issue that is causing problems for everyone in that part of the country. Until that is resolved, everyone in Assam is in the same situation regarding gas evacuation.

Manpreet Arora – The Northern Lights Wealth: All right. Just another clarification, sir, regarding perhaps the

Operator: Sorry to interrupt, Mr. {? Mandke ?}. May we request you to return to the queue for follow-up questions so that there is time for other participants?

Management: Certainly. You can drop us an email with anything you have, and we will answer it by email.

Manpreet Arora – The Northern Lights Wealth: Thank you, sir.

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Operator: Thank you. The next question comes from the line of Priyankush Sarkar with Square 64 Capital Advisors LLP. Please go ahead.

Priyankush Sarkar – Square 64 Capital Advisors LLP: Hi, good evening, sir. You do not yet have 2P reserves for the new fields that you won in the {? acre ?} round four. I wanted to get a sense of the reserves.

The existing portfolio has a certain amount of reserves. What kind of reserves are we talking about in the fields we won in DSF {? 4 ?}? I am sure you must have some estimates. Is it 2 times or 2.5 times the existing reserve base? Any sense of that would be helpful.

Management: Priyankush, in my opening remarks I said that potentially onshore KG has a reserve base that is larger than, if not equal to, our offshore reserve base. I have already made that remark.

Beyond that, I think it would be premature to say more. We would like to understand it better ourselves, but it is potentially equal to, if not larger than, our offshore reserve base. We have already provided details of our offshore reserve base.

Priyankush Sarkar – Square 64 Capital Advisors LLP: Understood, sir. Do you have any specific update on pipeline connectivity? I know you touched upon this in the last question, but do you have anything more specific regarding pipeline connectivity in Assam? There is a push from the government due to the ongoing crisis in the Middle East.

Management: Not that I am aware of. We really do not have any update. This is something that stakeholders sitting at a different table need to resolve.

There is a regular northeast pipeline-connectivity group that meets, and we are always invited and attend. However, as far as we are aware, the issue has not yet been resolved. That is the simplest way to put it.

Priyankush Sarkar – Square 64 Capital Advisors LLP: Thank you, sir. That is all from my end, and I wish you all the best.

Management: Thank you, Priyankush.

Operator: Thank you. The next question comes from the line of M N Kumar, an individual investor. Please go ahead.

M N Kumar – Individual Investor: Congratulations on very good results. I definitely appreciate the cost control you have implemented over the last three years and the way the assets are being used.

I have two questions related to the balance sheet. Why has CWIP been so high? Most of our assets are in production, correct?

Rajiv: Rajiv speaking. Regarding CWIP, it is approximately 190 crores. I think around 100 crores is related to Duarmara.

You are right that all the Cambay assets are being put into production. However, we have spent some capital on Duarmara and our offshore assets, including activity studies and marketing studies.

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Of the 190 crores shown in CWIP, 100 crores relates to Duarmara. This will be capitalized once the field is put into production. The remaining amount relates to other fields, where activities continue because we are in a continuous drilling campaign.

You will see a significant amount being capitalized as the wells are brought into production. However, around 100 crores will be capitalized once Duarmara is put into production. I hope that answers the question.

M N Kumar – Individual Investor: Yes, that answers it. My second question is why our tax liabilities are growing substantially.

Rajiv: I presume you are referring to deferred tax liabilities.

M N Kumar – Individual Investor: Correct.

Rajiv: The way deferred tax liabilities work, Kumar, is that we are entitled to expense all the capex incurred toward drilling a well in the same year.

If you look at the cash component of the tax expense, on the tax books we are able to claim a 100% benefit for the expense. Until last year, our capex more or less matched our PBT. That is what has resulted in the accumulation of deferred tax liabilities.

You will see this continue because this incentive is not provided only to us; it is provided to the industry as a whole. Companies that invest heavily in drilling wells receive this benefit, and you will see it accumulate as we continue drilling wells.

M N Kumar – Individual Investor: When does it reverse?

Operator: Sorry to interrupt, Mr. M N Kumar. We request you to return to the queue for further follow-up questions, as several participants are waiting for their turns.

Rajiv: I will answer that briefly. As long as we continue drilling wells, you will see the tax liabilities being at least partially offset, given that we are on a growth trajectory.

The intent is not to create a large liability. The entire intent of the policy was to provide tax incentives to those investing in capital expenditure for drilling wells.

It is not simply a question of reversal. These liabilities will reverse when our revenues peak and, if we are not finding sufficient opportunities to reinvest the capital, you will see the cash or these numbers, in your terminology, reverse to some extent.

Operator: Thank you. The next question comes from the line of Shashwat {? Dhyani ?} with {? N B Alpha ?}. Please go ahead.

Shashwat {? Dhyani ?} – {? N B Alpha ?}: Hi, sir. Thank you for the opportunity. I have a couple of questions.

First, as you are guiding for a 5,000 BOEPD number for FY29, I wanted to check whether, within the Duarmara field, we are assuming gas offtake in that number, or whether it is largely based on

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Cambay plus Duarmara oil offtake.

Management: From an offtake perspective, let me address that. As I said, in these 5,000-plus numbers, as of now, we have very minimal contributions from the new KG fields and from Duarmara as well.

The reason is that this is a number we are committing to you. Until I understand the oil or gas potential of Duarmara and how that offtake will happen, we will not typically include those numbers in our forecast.

Therefore, there is very little contribution from what I call projects that are not yet fully mature in these numbers for the company.

Shashwat {? Dhyani ?} - {? N B Alpha ?}: I understand. Since the gas pipeline in Duarmara is still not completely resolved, I wanted to know whether we are confident of achieving this number despite that issue.

Management: Yes, we are reasonably confident in putting this number into the public domain.

Shashwat {? Dhyani ?} - {? N B Alpha ?}: Thank you, sir.

Operator: Thank you. Ladies and gentlemen, we will take that as our last question for today. I now hand the conference over to management for closing comments. Over to you, sir.

Management: Thank you very much for staying with us until late today and asking your questions. I know many people must have wanted to ask questions, but we ran out of time today because this was our first call.

Therefore, there will be many follow-up questions. Please feel free, as Rajiv said, to reach us at our investor email address. We commit that we will respond to your questions. Rajiv says within a fortnight, but I will commit that responses will be provided within a week as the queries come in.

Thank you for that. We hope this will become more interactive as we move forward and make it a regular feature of our outreach to our stakeholders and investors. Thank you very much, and we look forward to speaking with you at the end of next quarter.

Operator: Thank you, members of management. On behalf of Equirus Securities Private Limited, that concludes this conference. Thank you, everyone, for joining us. You may now disconnect your lines.

Note: {? ... ?} indicates a figure or name where audio clarity was insufficient for confident transcription. Verify against the source audio or the company's published filings.

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