Canacol Energy Limited

Q2 2020 Financial Results Conference Call

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CORPORATE PARTICIPANTS

Carolina Orozco - *Director Investor Relations*

Charle Gamba – *President, Chief Executive Officer, and Director*

Jason Bednar – *Chief Financial Officer*

PRESENTATION

Operator
Good morning and welcome to Canacol Energy Second Quarter 2020 Financial Results conference call. All participants will be in listen-only mode. Should you need assistance, please signal a conference specialist by pressing the star key followed by zero. After today's presentation there will be an opportunity to ask questions. To ask a question, you may press star, then one on your telephone keypad. To withdraw your question, please press star, then two. Please note this event is being recorded.

I'd now like to turn the conference over to Carolina Orozco, Director of Investor Relations. Please go ahead.

Carolina Orozco
Good morning and welcome to Canacol's Second Quarter 2020 Financial Results conference call. This is Carolina Orozco, Director of Investor Relations. I am with Mr. Charle Gamba, President and Chief Executive Officer, and Mr. Jason Bednar, Chief Financial Officer.

Before we begin, it's important to mention that the comments on this call by Canacol's senior management can include projections of the corporation's future performance. These projections neither constitute any commitment as to future results nor take into account risks or uncertainties that could materialize. As a result, Canacol assumes no responsibility in the event that future results are different from the projections shared on this conference call. Please note, that all finance figures on this call are denominated in U.S. dollars.

We will begin the presentation with our President and CEO, Mr. Charle Gamba, who will cover the operational highlights for the second quarter 2020. Mr. Jason Bednar, our CFO, will then discuss financial highlights. Mr. Gamba will close with a discussion of the corporation's outlook for the remainder of fiscal year 2020. A Q&A session will follow. Mr. Gamba is joining us on the line from Bogota, and Mr. Jason is joining us on the line from Calgary.

I will now turn the call over to Mr. Charle Gamba, President and CEO of Canacol Energy.

Charle Gamba
Thanks, Carolina. Good morning, afternoon, or evening, everyone, and welcome to Canacol's Second Quarter 2020 Conference call. Nominated contractual gas sales during Q2 2020 were 171 million standard cubic feet per day, a 35% increase in the same period in 2019. The cash revenues net of transportation during Q2, 2020 were $62.1 million, an 18% increase from the same period last year, but none of our take-or-pay gas sales contracts being in dispute during the quarter.

Nominated contractual gas sales for the second quarter of 2020 reached a low point of 156 million standard cubic feet per day in April and recovered to 185 million standard cubic feet per day in June. The demand beginning to recover after the country-wide lockdown related to COVID.

In the second quarter, we continued to execute our capital plan with no significant cut to our 2020 capital budget. We also continued to deliver on our return of capital to shareholders via the continuation of our quarterly dividend program with no cut. Unlike the majority of oil and gas companies operating here in Colombia, we did not suspend capital spending during the second quarter, but rather took advantage of the opportunity to secure a second drilling rig at a significant discount, along with a deep discount for the current drilling rig under contract. As I mentioned, we also continued to issue our quarterly dividend with no cut.

Production operations during the second quarter ran smoothly with no major interruptions. Drilling operations suspended on March 26, 2020, due to the national lockdown were resumed on May 27, 2020, after the lockdown was lifted. Biosecurity protocols in accordance with local and federal guidelines and laws have been implemented in all of our operations and offices, the priority being placed as always on the safety and health of our employees and contractors.

Finally, in a major show of confidence in the stability of Canacol's business model, our syndicated lenders extended our existing $30 million term debt facility at a lower interest rate than before and extended as a further $121 million in new low-interest term and revolving credit during a period where many oil and gas producers have their borrowing bases re-determined and cut.

I'll now turn the presentation over to Jason Bednar, CFO, who will discuss our second quarter financials in more detail. When he's done, I will provide detail on the outlook for the remainder of 2020.

Jason Bednar
Thanks Charle. Q2, 2020, was another strong quarter for Canacol both operationally and financially as we continue to execute our plan and drive our growing natural gas business forward. Focusing on the second quarter of 2020, financial highlights include revenues increasing 14% to $54 million compared to $48 million for the same period in 2019, adjusted funds from operations increasing 22% to $31 million from $26 million, EBITDA increasing 9% to $40 million from $37 million, and net income increasing 843% to $18 million from $2 million.

As Charle already outlined, sales volumes declined from Q1 levels, due to lower demand, however, thanks to the large pipeline capacity expansion project completed in late August 2019, and its related new take-or-pay sales contracts that came into force in the second half of last year, we still reported a 22% increase in funds flow from operations relative to the same period in the prior year, and with capital expenditures constrained slightly by COVID-related restrictions, we were able to generate $19.2 million in free cash flow before interest and dividend payments.

That's only slightly lower than Q1 and substantially higher than any quarter before that. That free cash flow supports our unchanged quarterly dividend that was initiated in the fourth quarter of last year, which currently represents an annual yield of approximately 5.8% with the last dividend paid in July. And the free cash flow also supports continued improvement in our leverage ratios. Our net debt to EBITDAX ratio is reduced from 2.3 times at June 30, 2019, to 1.8 times at June 30, 2020.

Our operating netback decreased 7% to $3.63 per Mcf in the three months ended June 30, 2020, compared to $3.88 per Mcf in the same period of 2019. The decrease is due to a lack of premium spot premium spot market gas sales, as a result of the lower demand driven by COVID-19 economic downturn. That decrease is partially offset by a reduction of operating expenses per Mcf to $0.25 per Mcf for the three months ended June 30, 2020, compared to $0.31 per Mcf for the same period in 2019.

As expected, increased gas sales allowed us to substantially decrease our operating costs on a per-unit basis. Given the COVID quarantines, we did defer some routine maintenance work in Q2 to the latter half the year, which effectively reduced Q2 opex and increased second half OpEx to some extent. Also notable is the decrease in royalty expenses to $0.64 or 14.1% in Q2 down, from $0.72 or 15.9% in Q1 of 2020. This results from the reduced sales in Q2 and our ability to shift production between blocks, allowing us to produce a higher percentage of that production from Esperanza block, which has a lower royalty rate. It is worth noting that we maintained strong operating margins of 80% during the quarter.

Relative to the first quarter of this year, we were actually able to increase our operating net back and margin very slightly despite significantly lower sales volumes, which I think, again, speaks to the strength of our business and the value of our sales contracts, in particular. We recorded net income of $17.7 million for Q2 2020, compared to $1.9 million for the same period in 2019.

Unlike Q1 of 2020, where we saw a large devaluation of the Colombian peso and recorded a large non-cash deferred tax expense, the peso strengthened in the second quarter of 2020, which allowed us to post an $11.6 million deferred tax recovery. Should the peso strengthen further throughout 2020, our net income would reflect further deferred tax recoveries. I'll also mention that the modest peso hedge we had in place expired on July 31, 2020, and the company now have no hedges in place.

Our cash and cash equivalents increased from $41.2 million at December 31, 2019, and from $49.2 million at March 31, 2020, to $58.5 million as at June 30, 2020. The financial strength and stability of our operations is giving us increased financial flexibility. As such we've been able to re-profile a portion of our existing debt as well as add a couple of other important pieces as announced last week. I won't go through the full details of everything we did, which is in the press release released last week as well as our financial statements and summarizes on the slide, but I will highlight some noteworthy achievements and give some insight as to the rationale for them.

So first of all, we were able to re-profile our existing $30 million term loan that we entered in December 2018, which allowed us to buy the Jobo 2 gas processing facility, and that's operated and lowered our OpEx at the same time. The facility carried an interest rate of 6.875%.

In June of 2020, as the first amortization payments were coming due, we renegotiated the rate down to approximately 4.5% to push out the first amortization payment to December of 2021. This 18-month extension adds approximately $16 million of additional liquidity to corporations through to the end of 2021, based on principal payments alone.

The second piece related to a new $46 million revolving credit facility, which is at approximately 5% interest rate, if and when drawn. Although Canacol landed Q2 with approximately $59 million of cash and can fund its capital and dividend programs with existing cash flows, we thought it prudent, given the favorable rates, to add to our financial flexibility.

Third and lastly, we negotiated a $75 million bridge term loan at approximately 4.5%, which resides inside the company that will build the Medellin pipeline. The first $25 million will be drawn shortly and will be used to fund expenditures such as engineering and environmental pruning through to June 2021. The remaining $50 million could be used to order long lead time items, such as pipe, when the timing is appropriate.

We anticipate that during the term of the bridge, Canacol will divest between 75% to 100% of the shares of this subsidiary to an equity partner, while maintaining up to a 25% working interest in the ownership of the pipeline project. Once the equity partners in bank syndicate agreements have been signed and any applicable conditions precedent have been met, we anticipate the long-term funding will be advanced, and the bridge will be repaid in its entirety.

These three debt deals come at a time when many North American oil and gas producers seem to be rolling over their debt without any significant improvement in terms. I think we can be proud of what we've achieved operationally, which underpins our ability to lower our cost of capital in this way and to secure substantially increased financial flexibility.

I think it's fair to say we're seeing our cost to capital decline as market participants come to understand the value of our business. On the debt side, that is reflected in these new terms and the expanded debt capacity, along the equity side, it is reflected in a very stable share price compared to many other oil and gas producers.

During 2020, the company plans to use its excess cash to, number one, maintain our quarterly dividend payment, which has been set at $0.052 Canadian a share, which is approximately a 6% dividend yield at current share prices, totaling approximately $13.5 million for the first half of 2020. Secondly, to continue to repurchase common shares of the corporation under our normal course issuer bid, when we feel it is right to do so.

In closing, our Q2 financial results were very strong and relatively stable, despite the challenges that the coronavirus pandemic presented. Now, we are in an increasingly enviable position of financial strength with flexibility to wrap up investment levels, when we think it makes sense to do so.

At this point, I'll hand it back to Charle. Thanks, everyone.

Charle Gamba
Thanks, Jason. The stability provided by our fixed term take-or-pay gas sales contracts have allowed us weather the financial effects of this pandemic up to this point. We've maintained our growth strategy and have not cut capital spending in a significant way. We've also maintained robust cash flow and operating margins, and it also maintained our return of capital shareholders to the continued issuance of a quarterly dividend, which we did not cut.

With respect to the remainder of 2020, we reiterate the gas sales guidance of between 170 and 190 million standard cubic feet per day. Due to the two-month delay in the drilling program related to the lockdown, anticipate drilling 9 of the planned 12 exploration development wells in 2020 with the remainder being pushed into 2021.

With respect to the capital budget, delays related to the lockdown and the above mentioned reduction of the drill count, anticipate paying approximately $108 million as opposed to the original $114 million. Currently we're drilling the Porro Norte-1 exploration well, located approximately 25 kilometers to the north or Pandereta field, located on our 100%-operated VIM-5 E&P contract. Porro Norte-1 is targeting a four-way anticlinal structural closure defined on 2D seismic potential gas-bearing reservoirs include the Tubara, Porquero, and Cicucco sandstones and limestones.

We're currently completing the Pandereta 8 well, and we'll then be mobilizing the other rig to the Pandereta 4 development well, which will test the potential western extension of the Pandereta field. We expect results from both wells in September.

Finally, I want to thank the entire Canacol team as well as our contractors, lending partners, and clients for their support and hard work during these very uncertain times.

We're now ready to answer any questions that you might have.

QUESTIONS AND ANSWERS

Operator
Thank you. We will now begin the question-and-answer session. To ask a question, you may press

star, then one, on your touchtone phone. If you are using a speakerphone, please pick up your handset before pressing the keys. To withdraw your question, please press the star, then two. At this time, we will pause momentarily to assemble our roster.

The first question will come from Gavin Wylie with Scotiabank. Please go ahead.

Gavin Wylie
Yes. Thanks, guys. Two quick questions for me. So, just looking for an update on what you're seeing in the spot market for Colombian gas pricing. As the economy has been slowly reopening, you've noted that gas demand, I think, got as low as maybe down 20% year-over-year back in April. I believe that was recovered to maybe only down about 5% year-over-year in June, July. Again, just wondering if you can give us a sense of what you're seeing in the spot market as we are still dealing with those record low hydropower reservoir levels?

Second question is just on production. Given the volatility that we've seen through the last couple of months, just wondering if you can give us what either July has averaged or what you're seeing quarter-to-date relative to the 165 million cubic feet a day that you averaged in June. That would be great. Thanks.

Charle Gamba
Thanks, Gavin. With respect to spot pricing and demand, we're entering in August, which will continue through to December a typically strong cycle of gas demand historically. These are the stronger months for gas demand, related to hydroelectric reservoir conditions. So, we're seeing as I think you've indicated good recovery of demand, and spot pricing of course is tagging along right with demand. So, as demand continues to increase, we see spot pricing coming back up away from those lows that we experienced in April and May certainly.

With respect to production, July and August, we're certainly well within the range of our published guidance, which would be between 170 to 197 million standard cubic feet per day. So, we're in pretty good shape.

Gavin Wylie
Are there any specifics that you'd be willing to give on the pricing that you're seeing, just either what July average for spot market sales, or on a dollar per Mcf basis?

Charle Gamba
No. We're not going to give any specific spot pricing. Just to say that as demand is recovering, spot price is increasing off Q2.

Gavin Wylie
Understood. Thanks, guys.

Operator
The next question will come from Josef Schachter with Schachter Energy Research. Please go ahead.

Josef Schachter
Good morning, everyone, Charle, Jason, and congratulations on a very nice quarter in these difficult times. Going back to the spot sales, the clients that are taking more gas, is it a few key clients that are taking more gas, or is it across the board that you're seeing pick up in demand? I'm just wondering if it’s related to individual customers or is it just an industry issue whereas the recovery of activity and business activity than it's picking up right across the board.

Charle Gamba
Yes. Thanks, Josef. Thank you for that question. Good to hear you. Spot sales are following sort of the traditional pattern. As you know, the majority of our gas sales goes to thermoelectric power generation companies located on the Caribbean coast, and that's where the majority of our spot sales typically go.

So, those would be to either existing clients that we have existing take-or-pay contracts to that require additional gas, which they buy on the spot basis, or to other clients that we do not have take-or-pay contracts with, other thermoelectric power plants that require gas.

So, I would say that the majority of spot sales, as always, go towards thermoelectric power plants. We're also selling spots into the regular industrial and manufacturing markets as well as demand has picked up there as well, but by and far, the large majority of spot sales traditionally goes to existing and other electric power clients.

Josef Schachter
Okay. Could you then go into what's going on in terms of the coronavirus, the reopening process of schools reopening, industry reopening? Are there any guidelines in terms of timeline for when that pace will pick up?

Charle Gamba
So, country-wide the lockdown was lifted in May, which allowed us to resume our drilling operations, for example, in the departments where we have those activities. There are still currently local quarantines within some of the major cities, the major cities for example of Bogotá, Medellin, and Cali. So, certain sectors of the city are currently under lockdown. For example, in Bogotá, approximately one-third of the city is under quarantine, about 1.7 million people affected by that quarantine. They've sort of been rotating the lockdown on a sector basis through the city.

All of those lockdowns certainly in Bogotá will end on August the 26th, but country-wide the lockdown was lifted in May. Hence, the majority of manufacturing and industrial, mining, thermal power generation has resumed in the majority of the country.

With respect to schools, for example, the schools are still virtual. There's no announcement of a plan to open schools anytime soon for return of students.

Finally, with respect to air travel and transportation, the federal government along with the local governments have started to reopen local airports for local air travel. And it's anticipated that international air travel will resume on September 1st, so that is essentially scheduled.

The coronavirus itself reaching daily records of cases. So, still very much on the uptick here in Colombia, with respect to the lockdown generally being lifted across the country.

Josef Schachter
Thank you for that answer. The last area for me is, you still have the Colombian oil numbers at 245 barrels down from 342 in the prior year. When do you see that being sold or off the books and no longer part of the business operations?

Charle Gamba
That oil production comes from our last remaining oil field, which would be the Rancho Hermoso Field, strangely enough our very first oil field in Colombia proves to be our very last field. We were in a sales

process for that that asset. We had concluded a negotiation with the party late last year, but that sales process fell apart basically, and as a result, we continue to operate that field, which at this current time is still economic, believe it or not. We're still receiving positive netbacks, and we're making positive netbacks even at the lowest point of oil production. It is a very mature oil field.

We will continue with our efforts to try and sell that asset. And in the meantime, we will continue to operate that field at the minimum operating type conditions.

Josef Schachter
Super. Thank you very much, and congratulations again for the good quarter.

Operator
Once again, if you'd like to ask a question, please press star, then one.

The next question will be from Harry Malcolmson, investor. Please go ahead.

Harry Malcolmson
Thank you. In the corporation's press release in November, it said that, with respect to the Medellin Pipe Project, the corporation anticipates executing a take-or-pay sales contract with a major utility during the current month of November. Then, in December, you indicated that the execution of a definitive agreement to construct a new gas pipeline will be undertaken. Or what are your targets for the 2020 year?

At this point, it's apparent that those expectations were not realized, and I note that you have undertaken a workaround arrangement, which is constructive in the circumstances. I'm unclear, however, with respect to this pipeline, why the investor group that participated in the first pipeline consortium, it was reluctant, presumably, to participate in a further on. Basically, what are the factors that resulted in those reservations? And in particular, was that a concern about LNG projects that might impact the economics of the second pipeline? Thank you.

Charle Gamba
Thanks, Harry, for those questions. Yes, with respect to the pipeline project in Medellin, we do have a long-term take-or-pay gas sales contract negotiated with the primary offtaker there. There were several events in Medellin at year-end, which impacted the execution of that contract, primarily a change in the mayor of Medellin, who has some authority with respect to contract execution. So, there's a change in there basically, and then, the client essentially with along with every other major client here in Columbia was faced with the challenge of COVID, which they're still essentially faced with today.

So, the process has been very slow, but I will say that number one, there is a take-or-pay sales contract negotiated to both parties' satisfaction. Number two, we continue in discussions with that client working towards the execution of that contract in the near term.

All of the investors in the project, the consortium that we have formed and the investors we have attracted to this project, along with our banking support, are fully aware of the status of these negotiations and comfortable to the point of moving forward in the financing that Jason just outlined.

With respect to the other pipeline operated in Colombia that you referenced, we do have a number of parties who are interested in participating in the EPC contract, which will be responsible for the construction of that pipeline, including several national pipeline operators. So, I hope that answers your questions, Harry.

Harry Malcolmson
Thank you

Operator
Our next question will be from Nicolas Erazo with CrediCorp Capital. Please go ahead.

Nicolas Erazo
Hi, everyone. Good morning. Hope you guys are all well. Just one question about the deferred delivery you guys posted on the press release in July. We saw it in the report of July that the additional nominations for deferred delivery were around 12 to 14 Mcf per day, but on the second quarter report yesterday, there is a figure of undelivered natural gas and LNG nominations of about 19 million cubic feet per day.

So, just to get to know what we are missing there, because on the press release of July, we expected between 12 million and 14 million, and now the report says about 19 million. So, just to get an understanding of that figure, please.

Jason Bednar
Sure. I can certainly answer that. It's a great question, because it is a bit confusing. So, I'm going to start at the 19 million. As you know, people historically, they can defer a portion as long as they pay for it, and they typically have 12 months to come and collect that gas.

With COVID times, as we described in the previous quarterly conference call, we allowed people to defer additional volume. So, that gross amount of deferral was indeed the 19 million that is in the MD&A and discussed here today. If we go back to the first part of the question as people take their nominations in that 12-month cycle, they can then again defer some further nominations during that period. So, the gross nomination deferrals for Q2 was 19 million, but 6 million actually collected their gas, leaving the net deferrals at the 13 million. I hope that's more clear.

Nicolas Erazo
Perfect, Jason, and just a follow-up. Given that the take-or-pay contracts have been sort of changing and given the flexibility you guys have made, which is great progress, what main changes besides the ability to defer volumes has been made on these type of contracts, meaning the take-or-pay contracts in terms of prices, in terms of tax effect against the U.S. dollar to be fixed or something? We know that's something that has been changing a little bit in the couple of months.

Jason Bednar
Okay, yes, great follow-up questions. So, none of the prices have been changed. These are contracts. They're essentially set in stone. As we've said there has been no instances of force majeure, as we explained on the last call. Force majeure simply doesn't apply, and the contract prices are what they are.

We have allowed some people to defer them. Also, on this particular topic, if you looked at our financial statements, there's about $15 million in deferred revenue; $5 million of that has actually been prepaid and not even nominated at this stage. For one reason or another, some of our offtakers simply prepay us for a full year of gas, which means the remaining $10 million has been what I described.

Also involved in this equation is the notion that we told certain offtakers when we allowed them to defer volumes that they had to take all of their contractual downtime for the year. A typical offtake contract has about 6% downtime embedded in it to allow the offtakers to do things like plant turnarounds. Not everyone's going to take all 6% but if they chose deferral, they would have to take all their downtime during the period that they deferred. So, in one specific instance, one offtaker took all of their downtime days during the period of Q2.

Nicolas Erazo
Understood, Jason. Really helpful. Thank you.

Operator
Again, if you have a question, please press star, then one.

The next question will be from Ricardo Sandoval with Bancolombia. Please go ahead.

Ricardo Sandoval
Hi, everyone. Thank you for the presentation, and congratulations for the results. I have just one question at the moment and it's about EPM. I just want to know what happened with EPM's Board of Directors? I guess what happened in Medellin during this week with the Board of Directors of EPM and how this would affect the negotiations of contracts for Medellin Pipeline. I understood that EPM was one potential client for you. So, I would like if you comment something about it. Thank you.

Charle Gamba
Hi, Ricardo. Thanks for the question. Yes, EPM is certainly one of the potential clients in Medellin with respect to sales contracts for the new pipeline. We are all aware of the issues, internal issues currently affecting EPM. However, they are the largest public utility in Colombia, a very sound financial structure, and obviously require a long and steady supply of gas for the coming decades. So, I would say that once they are through their internal structuring, I expect business will be returned to normal, and they will continue to be a significant potential client for us in Medellin.

Ricardo Sandoval
Okay, thank you.

Operator
Thank you. At this time I'm showing no further questions from the phone. So, I'd like to now turn the Q&A session over to Carolina Orozco, who will handle any submitted questions.

Carolina Orozco
Thank you, operator. We have one question from John Clark. "What are the service dates for power plants on Medellin Pipeline?"

Charle Gamba
Okay. So, I think I've already discussed the Medellin Pipeline and where we're at with that project at the moment. With respect to the power plant, the power project, which we are participating with Celsia here in Colombia, the El Tesorito Power project. It's a 200-megawatt electric power plant that will be constructed approximately seven kilometers to the south and west of our Jobo treatment facility.

The project is ongoing. The EPC contract was awarded in June. All environmental permits have been received by the consortium and the project is on schedule for December 1, 2021, start date. Our interest in the project, of course, is primarily related to the gas sales contract that we have with the consortium. So, that's the update on the El Tesorito Power project.

Carolina Orozco

The next question is from Daniel Garguilo from BTG Pactual. “In second quarter 2020, we saw spot volumes affected by the nationwide lockdown but somehow offset by greater demand from power thermal generators, due to weak hydrology. But in the last couple of months, hydrology has been rapidly recovering which should reduce demand from gas power plants in the spot market. In that sense, I would like to know the potential implications in terms of pricing of this lower demand from generators.”

Charle Gamba
Well, we did see unusually strong from thermoelectric power consumption in the second quarter in what is normally a fairly wet period of time, when thermal demand is quite low. however, if you look on a historical basis at sort of peak gas demand in the coast, the lowest demand months are in fact second quarter months, April, May, and June, and then gas demand starts to pick up noticeably through the second half of the year beginning August through December.

So, we're actually entering historically a fairly strong part of the demand cycle on an annual basis where we see overall demand including thermal demand historically being at its highest point historically through August through December. So, I would say that what was very uncharacteristic this year, the unusually high thermal demand during April, May, and June, which is normally a very low period of demand historically.

As I mentioned a little earlier, from one of the speaker's questions, the spot pricing is intimately related to demand. So, if demand follows its historical path of strengthening through the second half of the year, we should see spot prices react accordingly. If demand is weak, due to COVID or any other macroeconomic factors, we would expect to see spot prices be equally as weak. So, I think at this point in time, we're pretty much forecasting our range of guidance 170 to 197, based on historic demand coupled with the effects of coronavirus, and spot pricing certainly is expected to be in sync with demand. So, if demand is strong, spot pricing will be good; if demand is weak spot pricing will be weak.

Carolina Orozco
The next question is from James Branch. “Is there any execution risk to getting investors in the new pipeline?”

Jason Bednar
Perhaps I can answer that, Charle. So, I’ve probably said on previous calls, the pipeline is split into two components, one being debt, one being equity. We've had multiple, ongoing discussions for the better part of a year with respect to that split. At this point in time, I expect the pipeline will be funded by approximately 30% equity and 70% debt.

If I look at the debt side, we've been working with two large banks, which I expect to be the leads on that. Even pre-COVID times, I had term sheets on my desk with respect to conditions precedent and interest rates, etc. In the ongoing discussions, I don't expect that to change. So, I feel the debt side will come together, and we've had abundant interest.

On the equity side, it's expected to be private equity that will put up the equity component with Canacol, of course, owning up to 25% of the equity. There has been abundant interest and continues to be abundant interest in that. Obviously, different private equity firms have different IRR hurdles, and obviously, we are looking to work with those that have the lowest IRR hurdles, as the lower their expected IRR, the lower the pipeline tariff would be to Canacol and, hence, the higher the net back we would get on our delivered gas to EPM and the other offtaker.

So, I've seen no decrease in the amount of interest, and I've actually seen arguably an increase in the interest in this particular project.

Carolina Orozco
Next question is from Daniel Duarte from Corficolombiana. “Good morning and thank you for taking my questions. What is the total estimated cost of the Medellin Pipeline Project? What is the average gas sales price or just the take-or-pay contract?”

Charle Gamba
The total cost for the pipeline, it's an approximately 300-kilometer long, 20-inch pipeline extending from our gas-producing facility at Jobo, which is located in the department of Cordoba, and it will connect into Medellin City Gate in the Department of Antioquia. The first phase construction is a plan to not include much in the way of compression. So, the first—

Operator
Pardon me. This is the operator. It appears his line has disconnected at this time. We'll get him connected as soon as we can. Thank you so much.

Jason Bednar
Carolina, if you maybe want to focus on some of the questions that are more financial and directed my way, I can carry on.

Carolina Orozco
Sure. So, we received some questions from Luis Carballo from UBS. The first one is, “I'd like to understand better your netback outlook for the next quarters.”

Jason Bednar
Okay. So, with respect to netbacks moving forward, let's just go through the components of the netback, if we can. Obviously, the largest component with respect to netback is going to be the sales price. So, if interruptible demand continues to—and I'll cover off a couple questions that I see on my screen here. What is our average contracted price for the Medellin? That would be $4.72 net of transportation. So, obviously, the interruptible sales price can move that average up or down, and at times it certainly moved it up. Obviously during Q2 it moved it down. So, depending on demand recovery, there's still a bit of a question mark with respect to what that top line revenue number would be net of transportation.

The next component, of course, would be royalties and in Q1, we saw a royalty rate of 16%. Obviously, we did approximately $202 million of sales. In Q2, doing reduced sales, we were able to shift some of that production or produce more on a percentage basis rather from the Esperanza block, which has lower royalties, which I touched on earlier during my presentation.

So, in Q2, the royalty went down to 14%, once again, whereas Q1 was 16%. So, once again the royalties are probably would end up in that 15%-ish range, which would be $0.68 to $0.70 essentially.

The final factor, of course, would be operating costs. So, we can see in Q1, while we were producing large volumes, our operating costs were $0.22. In Q2, when we produced less volumes, the operating costs were $0.25. The operating costs are largely fixed, being the cost to operate the Jobo gas plant. The less volume you put through there, the higher the OpEx on a per-unit basis

So, those are the components. I will say that we have averaged historically going back to Q1 of 2018 as was on one of the slides earlier, anywhere between 78% to 81% operating margin. I don't expect that to change significantly through the latter half of the year. So, those things are all really dependent upon the interruptible sales markets and the price assumption that you may want to use for that.

Carolina Orozco
Charle is now back in the line, so I'm going to read again the question he was answering. "What is the total estimated cost of the Medellin Pipeline Project?"

Charle Gamba
The total estimated cost of that project, 300-kilometer-long pipeline project, is around $400 million for the phase 1 cost, which will not include much compression.

Carolina Orozco
The next question is from Luis Carballo from UBS. "Can you please share some update about the new pipeline?"

Charle Gamba
Yes. I think we've covered that topic here.

Carolina Orozco
Okay. The last question from Luis Carballo from UBS is in terms of demand. "You mentioned about the lockdown scenario. Being on the ground, what is your expectation about full natural gas demand recovery with the new rules released by the government?"

Charle Gamba
I expect demand will be highly dependent upon the course the virus takes going forward in Colombia, specifically if there is an inability to lower the incident rates or the contagion rate. There might considerably be a requirement for another lockdown, for example, to contain the virus. We hear a lot about first and second waves, and Colombia is very much in the midst of the first wave, with cases increasing on a daily basis reaching new record highs on a daily basis.

So, the outlook with respect to the trajectory of the virus remains quite uncertain, and I think quite important with respect to the demand in general and economic recovery. If the virus continues on this path, and if there is indeed a second wave, I expect that we will see a demand hit.

If this wave is controlled and a second wave, so to speak, does not materialize or is also controlled, then I expect demand to recover. That would be my thinking, so highly dependent upon what the federal and local governments do with respect to lockdowns in response to the course of the coronavirus.

Carolina Orozco
Finally, we have time for one last question from Mario Falbaum from First New York. "Coal, fuel, electricity is being decommissioned in many countries. Do you expect any move in Colombia to decommission plans?"

Charle Gamba
Thanks for that question, Mario. Yes, there are a few remaining coal-fired thermoelectric power plants, primarily on the coast, and Colombia of course is a signatory to the Paris Climate Accords, and Colombia has strict goals with respect to CO_2 emissions and targets for 2020. So, the federal plan with respect to the plan for energy that the government unveiled in January this year, includes the gradual cutting out of coal-fired thermoelectric power plants and a substitution of that with natural gas.

Eventually, of course, by the 2050 government plans to have a significant percentage of the energy matrix being supplied by renewable forms which would include wind and solar. So, natural gas will play an important part in a transition away from coal and oil-fired power generation towards eventually an energy matrix dominated by renewables and gas will, as I mentioned, sort of fill the in-between period from 2020 to 2050 in that transition that the government has mandated.

CONCLUSION

Carolina Orozco
With this, we conclude our conference call today. Thank you, all, for participating in our second quarter conference call. Please join us again in November for our third quarter 2020 conference call. Have a great day.