FINAL TRANSCRIPT

Enerplus Corporation

Q3 2022 Results Conference Call

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CORPORATE PARTICIPANTS

Drew Mair
Enerplus Corporation — Manager, Investor Relations

Ian Dundas
Enerplus Corporation — President & Chief Executive Officer

Wade Hutchings
Enerplus Corporation — Senior Vice-President & Chief Operating Officer

Jodi Jenson Labrie
Enerplus Corporation — Senior Vice-President & Chief Financial Officer

CONFERENCE CALL PARTICIPANTS

Greg Pardy
RBC Capital Markets — Analyst

Jeoffrey Lambujon
Tudor, Pickering — Analyst

Travis Wood
National Bank Financial — Analyst

Jamie Kubik
CIBC — Analyst

PRESENTATION

Operator

Good day, ladies and gentlemen, and welcome to Enerplus' Q3 2022 results conference call. At this time, all lines are in a listen-only mode. Following the presentation, we will conduct a question-and-answer session.

If at any time during this call you require immediate assistance, please press *, 0 for the Operator.

This call is being recorded on Friday, November 4, 2022.

I would now like to turn the conference over to Drew Mair, Manager of Investor Relations. Please go ahead.

Drew Mair — Manager, Investor Relations, Enerplus Corporation

Thank you, Operator, and good morning, everyone. Thank you for joining the call.

Before we get started, please take note of the advisories located at the end of our third quarter news release. Our financials have been prepared in accordance with US GAAP, our production volumes are reported on a net-after-deduction-of-royalty basis, and our financial figures are in US dollars unless otherwise specified.

I'm here this morning with Ian Dundas, our President and Chief Executive Officer; Wade Hutchings, Senior VP and Chief Operating Officer; Jodi Jenson Labrie, Senior VP and Chief Financial Officer; and Shaina Morihira, VP, Finance.

Following our discussion, we will open up the call for questions.

And with that, I will turn it over to Ian.

Ian Dundas — President & Chief Executive Officer, Enerplus Corporation

Well, good morning, everyone. Thank you for joining us today.

Our positive operating momentum this year continued through the third quarter. Total volumes were up 15 percent from the second quarter with liquids production of 20 percent, outperforming our forecast. We expect the strong production to continue through the end of the year and are guiding the Q4 volumes of 105,000 to 110,000 BOE per day, including liquids production of 64,000 to 68,000 barrels per day.

This guidance takes into account the Canadian production we divested in the fourth quarter, and so while total production in Q4 looks broadly flat to Q3 at the midpoint, there is some underlying growth, which is offsetting the divestment impacts.

This outperformance has taken our annual production forecast higher, and we have increased our 2022 production guidance. This guidance update points to an increase in annual liquids production by 1,000 barrels per day at the midpoint.

Although we continue to experience cost inflation, our efforts to drive workflow efficiencies and our strategic approach to procurement have helped to dampen the inflationary impacts to our business this year. As a result, we continue to operate within the previously stated 2022 capital spending guidance. We have set our '22 capital spending at $430 million from our previous range of $400 million to $440 million.

A combination of production outperformance, cost control, and strong oil and gas prices we're realizing is driving a robust free cash flow profile. In the first nine months of 2022, we have generated almost $570 million of free cash flow. This has allowed us to reduce our net debt by almost 40 percent and return over $270 million to shareholders through share buybacks and dividends through the end of

September. And with the compelling free cash flow profile forecast in the fourth quarter, our debt reduction and return-of-capital initiatives are on track.

Between the end of September and November 2nd, we repurchased 2.7 million shares for a cost of $44 million, bringing our total share repurchases for the year to approximately 8 percent of our outstanding shares. And, as announced yesterday, we have increased our dividend by 10 percent, effective with the December payment.

Moving on to divestments. Earlier this week, we closed the previously announced sales of certain assets in Canada for a total consideration of C$140 million prior to closing adjustments. And on Wednesday of this week, we announced the sale of our remaining Canadian assets for C$240 million, again, prior to closing adjustments. With these transactions, our Canadian divestment process will be concluded for a total consideration of C$385 million before adjustments.

I want to thank our current and former staff for their professionalism in managing these assets with such a commitment to safe, responsible, and efficient operations.

I'll leave it there for now and turn the call over to Wade for an operational update.

Wade Hutchings — Senior Vice-President & Chief Operating Officer, Enerplus Corporation

Thanks, Ian, and good morning, everyone.

Total third quarter production grew to just under 108,000 barrels of oil equivalent per day, including about 68,000 barrels per day of liquids. These robust quarterly volumes were driven by an active completions program during the second and third quarters and well performance that has exceeded our expectations. Volumes were further supported by strong performance in our base production wells.

Over the course of the last two quarters, we brought 32 gross wells on production across five pads in North Dakota with eight of those wells occurring in the third quarter. High-quality locations and our ongoing completions optimization have driven solid production rates across this year's program. Our 2022 wells have averaged approximately 2,300 BOE per day per well on a peak consecutive 30-day basis.

We're very pleased with this year's performance. These pads are in well-established areas, which we would consider 10 percent to 15 percent above our average quality, and they've been exceeding this. However, these are still somewhat early time production results, and we're, therefore, not changing type curves or assuming this performance sustains in our forward program. But these results are encouraging, and they are driving very strong 2022 performance.

In terms of remaining completions activity in North Dakota for the year, we anticipate bringing five operated wells online in the fourth quarter along with some non-operated activity.

Moving on to inflation. We have continued to experience upward cost pressure, primarily in our capital program. Previously, we had been forecasting $6.5 million for total well cost in North Dakota in 2022, inclusive of drilling, completions, facilities, and the first lift system. Our latest projection is that we will average $6.9 million per well this year.

As we look ahead into 2023, we expect to see another 10 percent increase to our well cost with steel followed by sand and other consumables and then labour and other service costs being the most significant items leading to higher anticipated cost.

Lastly, turning to our non-operated Marcellus position. We participated in 10 wells, which were brought on production during the quarter with an average working interest of 13 percent. Well performance continues to be solid with peak consecutive 30-day production rates of over 30 million cubic feet per day per well. We expect an active fourth quarter in terms of wells coming online in our Marcellus position, which is projected to drive natural gas production growth for us in the fourth quarter.

I'll leave it there and now pass the call to Jodi.

Jodi Jenson Labrie — Senior Vice-President & Chief Financial Officer, Enerplus Corporation

Thanks, Wade. I'll start with our realized prices during the third quarter. In the Bakken, we realized a sales price premium to WTI of $2.41 per barrel. Bakken crude continues to be strongly bid, and the premium pricing is supported by significant excess pipeline capacity in the region and strong prices for crude oil delivered to the US Gulf Coast.

With Bakken oil prices continuing to trade at a premium to WTI, we have strengthened our 2022 Bakken oil price differential guidance to $1.25 per barrel above WTI.

For natural gas, our realized Marcellus price was $0.99 per Mcf below NYMEX in the quarter, and we are still on track to meet our 2022 guidance of $0.75 per Mcf below NYMEX as we transition into cooler winter weather during the fourth quarter.

Operating costs were $10.47 per BOE in the third quarter, an increase from the prior quarter, largely attributable to higher-planned well service activity and an increased liquids production weighting in the third quarter. We anticipate operating costs will trend lower in the fourth quarter, partly as a result of the recently closed Canadian asset divestments, which had higher operating costs than our corporate average. As a result, we have left our full year guidance unchanged at $10 per BOE.

We recorded current tax expense of just under $8 million in the third quarter. And, based on the current commodity price environment, we continue to expect 2022 cash taxes of 2 percent to 3 percent of our adjusted funds flow before tax.

Our third quarter adjusted net income was $208 million, and adjusted funds flow was $356 million. With capital spending at $114 million in the quarter, we generated free cash flow of $241 million, which we allocated towards debt and returning capital to shareholders.

We reduced net debt by 28 percent quarter over quarter and ended September with net debt of $391 million. We returned $123 million to shareholders in the third quarter, including $11.5 million in dividends and $112 million, or 7.9 million shares, repurchased. We plan to continue buying back shares under our current framework of at least 60 percent of free cash flow and have a robust return-of-capital plan for the remainder of this year.

In total, from January through early November this year, we have returned $327 million through share repurchases and dividends, which includes our announced December dividend.

Earlier this week, we announced the sale of our remaining Canadian asset, which is expected to close in December. This was part of our previously announced plan to continue to focus the portfolio on our strategic position in the Bakken. The proceeds from the divestment will accelerate the deleveraging of our balance sheet in 2023, giving us additional flexibility to support our plans to return at least 60 percent of free cash flow through dividends and share buybacks.

Lastly, during the third quarter, we entered into new 2023 natural gas hedges to support the strong free cash flow profile of our Marcellus asset. We've added costless winter collars at approximately $6.25 by $18 per Mcf and costless summer collars at approximately $4 by $7 per Mcf.

I'll leave it there, and we'll turn the call over to the Operator and open it up for questions.

Q&A

Operator

Thank you. Ladies and gentlemen, we will now begin the question-and-answer session. Should you have a question, please press *, followed by the 1 on your touch-tone phone. You will hear a three-tone prompt acknowledging your request, and your questions will be polled in the order they are received.

Should you wish to decline from the polling process, please press *, followed by the 2. If you are using a speakerphone, please lift the handset before pressing any keys. One moment, please, for your first question.

Your first question comes from Greg Pardy of RBC Capital Markets. Please go ahead.

Greg Pardy — RBC Capital Markets

Yeah. Thanks. Good morning. And thanks for the rundown. The questions I had are mostly on the financial side. I mean the operations look great. Just given the strength of the balance sheet and the pace at which you're deleveraging, what would the appetite be for a substantial issuer bid either later this year or next year?

Jodi Jenson Labrie

Yeah. Thanks, Greg. It's Jodi. We've stated previously that the substantial issuer bid is opportunities, a tool in the toolkit, and we would continue to consider this. Right now, the normal course issuer bid actually gives us a lot of flexibility to buy back our shares, and, as we mentioned, we're committed to returning at least 60 percent of our free cash flow through 2023. So I think we won't comment on potential timing, but it's definitely a tool that we can use.

Greg Pardy

Okay. Thanks for that. And then the second question, just more technical. So I understand the cash tax position this year. In terms of maybe as a percentage of pretax FFO for next year, is your thinking that you're still sort of an 11 percent, 12 percent range, give or take, in terms of cash tax in '23?

Jodi Jenson Labrie

I'd say that might be a little bit high at this point. I'm just basing that on how commodity prices are shaking out this year as well as current strip prices. So I think if you use strip pricing at this point, it's probably in that 8 percent to 9 percent range for next year.

Greg Pardy

Okay. Great. And last question for me. You mentioned what the, you know, just in the basin differentials were to TI in the Bakken in the quarter. Where are they currently? $4 or $5?

Jodi Jenson Labrie

No. Maybe that might be Clearbrook. So then you have to take a couple bucks off that for transport. So I would say it's probably $2, plus $2 to $3 in the basin right now.

Greg Pardy

Okay. Terrific. Thanks very much.

Jodi Jenson Labrie

Thank you.

Operator

Thank you. Once again, ladies and gentlemen, if you do have a question, please press *, 1 at this time.

The next question comes from Jeoffrey Lambujon of Tudor, Pickering. Please go ahead.

Jeoffrey Lambujon — Tudor, Pickering

Good morning, everyone. Thanks for taking my questions. My first one is just on the solid Q3 y'all delivered, particularly on the productivity front. And I apologize if I missed this earlier in the call, but just looking at how strong quarter-to-quarter liquids growth was in comparison to your prior expectations, I was wondering if you'd talk a bit about the components there, both in terms of performance and timing.

If there are any comments you can share on how you're seeing the program evolve into next year, whether in terms of how productivity might compare or in terms of how activity might be allocated to where you've been active recently versus developing other areas of your core.

Wade Hutchings

Yeah. Thanks for the question, Jeoffrey. This is Wade.

The key drivers for the Q3 liquids and total volume performance really, the biggest driver has been recent well performance. So we highlighted this last quarter, but that fairly large tranche of wells that came online in the second quarter continued to perform strongly into Q3 and throughout Q3. And then we brought on a few new wells in Q3 that also are performing strongly.

So that's the biggest driver. We also saw really good up-time performance in our base business, and that helped us with volumes in the quarter as well.

In terms of thinking about how that would translate into next year, I'll comment on two components; one would just be overall performance, and then the mix of wells.

So as we noted last quarter, we noted again this morning, these wells have exceeded our expectations. And on average, these pads that we brought online in the second and third quarter this year have been even higher quality than our average pad. And so we expected them to be strong, but they've even exceeded our expectations.

We're not baking that into our forward-type curves or forward performance. We're going to continue to use the same kind of optimization methods on the upcoming year's program that we did on those. So we feel like we still have an opportunity to continue to improve, at least in kind of short-term initial production performance. But again, we haven't baked that in for next year. We wouldn't really guide people to do that.

In terms of next year's program, it is an important year for us in that we will be shifting to a more diverse mix of locations that we'll be bringing online. So next year we'll have several pads from the Dunn County area, we'll still have a core of the programs in our core Fort Berthold program, and then you may even see us bring wells on in the eastern side of Williams County.

So next year will be a bit more diverse than this year. But we still feel like it'll be a strong program.

And then maybe just let me come back to this optimization question. We really have spent a lot of time as subservice and production operations teams looking at how can we optimize every well that we bring on. And so we've gotten a very customized approach to every pad and every well in terms of tweaks to the completion design, the landing zone, the spacing, particularly paying attention to existing offset producers that we operate or that someone else operates around us. And we think that's having a positive impact on our well performance.

Jeoffrey Lambujon

Great. That's fantastic detail. Thanks for that.

And then as my follow-up, also, as we think about next year just given the moving pieces on the volume side related to the success y'all have found on asset sales, how are you thinking about volumes overall next year relative to this year on a pro forma basis?

And then given the dynamic service and inflation environment that we all know about, as you work with service providers unlocking in contracts and pricing for next year, any refresh thoughts on how that'll impact year-to-year budget expectations at this point?

Drew Mair

Hey, Jeoff. It's Drew. I might just jump in there on the production question. No. No change to how we're thinking about the growth, the 3 percent to 5 percent growth from our liquids, but we do think about that on a divestment-adjusted basis. So you really need to back off the, you know, call it 6,000 BOEs a day that we've sold this year and then reset expectations. So directionally, it's going to look very similar to that 3 percent to 5 percent growth we talked about. But yeah. Just more of a divestment-adjusted number now.

And capital, do you want to take that, Wade? Sorry. I'm blanking on the capital question. What was that, Jeoffrey?

Jeoffrey Lambujon

Yeah. Just as you work with service providers on locking in contracts and pricing, just wanted to see if there's any new thoughts to expect on the budget year to year or next year or if we should wait until February and year-end earnings to get more colour on that.

Wade Hutchings

Certainly, we'll give you more colour, certainly at the start of the year, but we can comment a little bit on what we're seeing today. As we noted in our prepared comments, we do anticipate seeing capital costs driven up a bit next year, maybe on the order of 10 percent relative to where we'll average on well costs for 2022.

And I'll make just a couple of component comments. In terms of securing the critical services to deliver next year's program, we feel like we're already very well positioned. The two rigs that will run next year, we've actually had on contract since 2021, and we've got those priced, given the pricing environment that we were in at that point. Now this year, we've added a little bit of labour cost to those contracts just to reflect current conditions, but we'll roll into 2023 with two well-functioning rigs at what we feel like are pretty attractive pricing.

The frac crew that we'll use next year is already secured. It's the same company vendor that we've used since 2021. And the contract is one that we signed in late '21. Again, we've adjusted it up a bit to reflect inflationary conditions, but those two key components, we feel very good about in terms of both having the services secured but also good about the performance of those crews.

Two other components on the—one is steel. Steel has been one of the bigger drivers of the inflation we saw in our well costs this year, and it likely will be the key component for next year. We benefitted a lot in 2022 by having, essentially, pre-bought over half of the year's casing program at the end of 2021. And as that purchase kind of was used up, we've then been in almost a quarter-by-quarter mode, given the way steel prices have continued to escalate.

And so that's where we're at today. We'll just see what happens to steel prices next year in terms of, will they moderate and even roll over? But certainly, a key component of that 10 percent increase for next year is baked in because of what we think we're seeing on the steel side.

And then on sand, we've got all of the sand we need for next year secured. And it'll be a mix of in-basin sand and sand transported in. But we feel like we're well positioned for that as well.

Jeoffrey Lambujon

Perfect. That's exactly what I was looking for. Thank y'all.

Operator

Thank you. Once again, ladies and gentlemen, if you do have a question, please press *, 1 at this time.

The next question comes from Travis Wood, National Bank Financial. Please go ahead.

Travis Wood — National Bank Financial

Yeah. Thanks for taking my question here. I'll have two. First, on the operation side, I think you've done a pretty good job of laying out why you're seeing kind of improved results sequentially. But if you think back to the Bakken data that you guys highlighted back I think last spring, are you doing anything different since then?

And you showcased a lot of big improvement in terms of the completions and drilling side of the equation kind of over that five-year window. Should we expect that type of scale compression and cost advantage on kind of a per unit basis through into '22 numbers? And then ideally into '23 in terms of how you're continuing to push technology in different completions and drilling design into '23 as well?

Wade Hutchings

Yeah. Thanks for the question, Travis. In terms of what might be different relative to the investor day on our approach to development, I would say it's just been a continual evolution from that point. As we've noted this year, in addition to drilling and bringing online really high-quality pads in strong areas of our core position, we have continued to perfect or optimize the individual pad and well development configuration.

So what I mean by that is taking a look at the existing producing wells in the pad or in the unit that we're developing, because most of the units we're developing do have some existing wells already there. And then, of course, these aren't islands. There's wells offsetting these units, either our own or other operators. So we've taken that all into account with a fairly well-calibrated, subservice model around original oil and gas in place and then design how many new wells we want to put in that unit, how far away from each of the producing wells they should be, how far spaced from each other they should be, how many are optimal for the Middle Bakken and then the Three Forks. And then we actually vary the simulation design for each of those wells based on those conditions.

And so that, we feel like has really done a good job of avoiding any impacts from depletion that we would see if we just went with a more standard design. And then we've also continued to optimize how we flow the wells back and the timing of the first artificial lift and how we design that. And so we think all of that is contributing, certainly a bit, to the well performance that we've been seeing.

We will continue to do that. As we move into next year's program and beyond, we would anticipate that we'll be able to continue to find some optimizations. I think that the new dynamic for 2023 and beyond is we will be bringing wells online across the much bigger part of the Williston Basin. Our past several years' history has been almost exclusively in the Fort Berthold core position. And next year, as I noted, we'll have some wells in Dunn County, and over time we'll have some more in Williams County.

In terms of the technology application, I would say those who bet that there won't be any new technology efficiencies have been wrong for the last several years. So I'm pretty confident we'll keep finding those.

I think the things we're most excited about today are leveraging the ESG power management package we have on one of our rigs where we've upgraded the engines. We've got a battery pack, and we're able to actually displace a fair amount of our diesel costs by being able to leverage CNG as a fuel source in those operations. I think you'll see that kind of activity continue for us. We'll expand that into more and more of our operations where we can. I think the use of this in-basin sand is going to be helpful from a logistics and even potentially technology perspective as well.

Travis Wood

Okay. Thanks. That's great colour. Thanks for going over that again.

And then second question, probably for Jodi here, you commented on kind of balancing the NCIB with the SIB. Using the language of kind of at least 60 percent, if we start to see that expand through '23, is there a case that variable dividends or special dividends come into play given how you guys think of value in the stock and kind of intrinsic value on the buyback side?

Jodi Jenson Labrie

Yeah. Thanks, Travis. For sure. At this point in time, we continue to view buybacks as the best capital allocation choice for us today given the discount we see between our shares and our intrinsic value. But we remain open-minded to alternatives for returning capital. And if the stock keeps working, maybe there comes a point where we see less of a disconnect with this intrinsic value, and we would be open-minded to using other mechanisms such as variable or specials as you mentioned.

Travis Wood

Thank you very much. That's all.

Operator

Thank you. The next question comes from Jamie Kubik of CIBC. Please go ahead.

Jamie Kubik — CIBC

Yup. Good morning and thanks for taking my question. Maybe just to continue on to the questions around the block, and I mean, historically, there's been quite a bit of shaped volumes in Enerplus to start the year versus the exit. Are any of the well designs in areas that you're drilling going to affect how the shape of '23 should look? Or should we just expect it to look similar to what we've seen in the past? Thanks.

Wade Hutchings

It'll be similar, Jamie. Yeah. Just the nature of it, there's a little bit of a frac window there. This window will be two months or so, and we'll start bumping towards the end of January and into February. So there'll be a dip.

Jamie Kubik

Okay. And then maybe just in the total return to shareholders, the dividend, obviously, at a fairly small amount in that bucket. How should we think about that component of the return bucket versus the buybacks? I know Jodi just commented on that a little bit, but can you talk a little bit more about how you're thinking about the dividend?

Wade Hutchings

Yeah. I guess a few comments. A stable, growing, rock-solid dividend is an important part of the business. I don't think it's the most important part of an oil company's cap working profile these days. You can see that because we want it to be defensible in volatile commodity times. And so think about growth and think about that continuing.

Obviously, with the cash flows we're dealing with right now, we got a lot more going on. And as Jodi said, I guess we've approached it a couple of ways. We'll be responsive to the market, and we'll pay attention to market conditions, and we'll pay attention to if any of these differential structures get capitalized differently.

Right now, we don't really see that, and so we're anchoring it on mathematics. And we see a really powerful opportunity in our stock. We get the compounding effect of that. Over time, will we evolve it? We might. And again, it's going to depend upon valuation of the stock, I think.

Lots of people are thinking about these things right now. Again, we don't see any discernible trends other than it seems like we're being rewarded for this behaviour. And we see a lot of value underpinning the stock right now. So it's going to continue.

The questions around SIBs, and yeah. Clearly, that's sitting on the shelf ready to use if we need to use it. And we'll keep paying attention to this.

Jamie Kubik

Okay. That’s good colour. Thank you. I’ll turn it back.

Operator

Thank you. There are no further questions at this time. Please continue.

Drew Mair

All right. Thank you, everyone. Appreciate your time today. A very busy reporting day, busy reporting week. I hope everyone enjoys the weekend. Thank you. Bye.

Operator

Ladies and gentlemen, this does conclude the conference call for today. We thank you for your participation and ask that you please disconnect your lines.