FINAL TRANSCRIPT

Enerplus Corporation

Second Quarter 2023 Results Conference Call

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PRESENTATION

Operator

Good morning, ladies and gentlemen, and welcome to the Enerplus Q2 2023 Results Conference Call.

At this time all lines are in listen-only mode. Following the presentation we will conduct a question-and-answer session. (Operator instructions)

This call is being recorded on Thursday, August 10, 2023.

I would now like to turn the conference over to Drew Mair. Please go ahead, Mr. Mair.

Drew Mair — 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 second quarter news release. Our financials have been prepared in accordance with the U.S. GAAP, our production volumes are reported on a net after deduction of royalty basis, and our financial figures are in U.S. 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 Garth Doll, VP Marketing. Following our discussion, we will open up the call for questions.

With that, I will turn it over to Ian.

Ian Dundas — Chief Executive Officer, Enerplus Corporation

Thank you, Mr. Mair. Good morning everyone.

Our second quarter results and updated 2023 outlook reflect our strong operating momentum and commitment to returning meaningful free cash flow to shareholders. Operationally, we're seeing excellent well deliverability and solid execution will leave us well positioned to deliver on our targets this year.

Our first pads brought online in the Little Knife area are supporting this improved production outlook and further demonstrate the depth and quality of our core Bakken acreage. Wade will dig deeper into the results we're seeing from these pads in his remarks.

Based on this performance, we've increased our 2023 production guidance by 1,000 barrels per day at the midpoint with total production now expected to be 94,500 to 98,500 BOE per day. During the first half of the year, we generated $137 million in free cash flow and returned $133 million to shareholders through share repurchases and dividends. And in July, we repurchased the remaining shares under our normal course issuer bid authorization, having bought back 10 percent of our stock over the trailing 12-month period. This was the second consecutive year of repurchasing 10 percent of our outstanding share count. As we indicated in our second quarter news release, we will be renewing the NCIB for another 10 percent of shares outstanding later this month.

Given our half-weighted investment profile with approximately 60 percent of our capital spending in the first half of the year and the resulting build in production, we expect to generate approximately double free cash flow in the back half of the year based on the current price environment. With the strong free cash flow outlook, combined with our low leverage ratio of 0.2x, we plan to continue with a robust return of capital plan through the balance of the year. We expect to return at least 60 percent of our second half free cash flow to shareholders, and on a full year basis, this is expected to result in over 70 percent of our 2023 free cash flow being returned based on current market conditions.

Share repurchases will continue to comprise the majority of our cash returns, given our view that the intrinsic value of our business is not adequately reflected in our share price and, therefore, the buyback continues to be accretive to shareholder value.

A significant reduction in our share count over the last two years has meaningfully enhanced our per share growth. Our production per share increased by 24 percent compared to the second quarter of 2021, and over the same period our net debt decreased by almost 80 percent. Although we anticipate the majority of our cash returns will be via the share buyback, we have also increased our quarterly dividend by 9 percent, effective with the September payment.

In summary, our outlook is strong. We're on track to deliver another year of solid execution and well performance from our Bakken development program. We have an attractive free cash flow profile, a competitive return on capital strategy, and our financial position remains rock solid.

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

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

Thanks, Ian, and good morning everyone. North Dakota production averaged approximately 69,000 BOE per day in the quarter, which was up 3 percent compared to Q1. We continue to run two drilling rigs in North Dakota and drilled 17 gross operated wells during the quarter. It was a very active quarter relative to completion and onstream activity. By the end of the quarter, we brought 23 gross operated wells online, which will help set up a strong ramp in volumes in the back half of the year.

Notably, we brought our first two pads on production in the Little Knife area. We have a slide showing each pad's performance in our updated Investor Presentation.

At our Hay Draw Pad we have six wells producing that have averaged over 100,000 barrels of oil per well in 70 days on production. At our Bice Pad, we have three wells online which have produced about 80,000 barrels of oil on average per well through 40 days on production. These are great results and continue to support our view our Little Knife inventory is very high quality.

Although we do expect variability as we further develop the Little Knife area, we are pleased to see strong early production results from these first two pads. We continue to ground our view of ultimate recovery with a unit-by-unit recovery factor model while also seeking to optimize the early production performance of each well.

We also completed four re-frac operations during the quarter. As previously noted, these re-frac candidates in our portfolio are producing wells we acquired in 2021 in Dunn County which were completed several years prior to that. These wells and the units they are in have relatively low recoveries; we think there is potential to increase these with a modern restimulation.

Three of the four wells have been online for more than 30 days post re-frac and have averaged a gross peak 30-day rate per well of over 500 barrels of oil per day and over 800 BOE per day on a three-stream basis. This compares to a pre-frac average rate of 30 to 40 barrels of oil per day. These initial re-frac results are positive and in line with our expectations, and while we monitor the longer-term performance, we are evaluating plans for additional projects next year.

In terms of third quarter activity, we expect to bring 14 to 17 net operated wells on production in North Dakota. This activity, combined with our second quarter completions, is projected to drive liquids growth of approximately 10 percent in the third quarter compared to Q2.

Moving on to the cost environment, overall the market feels more balanced today than the tightness we saw last year at this time. Broadly, our well cost performance this year has tracked expectations. Our total well cost estimate coming into the year was $7.8 million for a two-mile lateral, up approximately 10 percent year-over-year. We're effectively on pace to realize $7.8 million or just under that on average for the year based on the current cost environment. While we will stay away from making any definitive deflationary calls about 2024 at this point, we do think the market is in a more stable place today with potential tailwinds into 2024. We do continue to capture lower casing costs each quarter.

Turning to our non-operated Marcellus position, as expected we saw quarterly volumes decline sequentially by 14 percent to 154 million cubic feet per day, driven by the limited capital activity this year. As a reminder, we're allocating just 2 percent to 3 percent of our 2023 capital budget to the Marcellus.

Lastly, I'll touch on our emissions performance this year. As highlighted with the release of our ESG report in June, we're driving quite meaningful reductions to our GHG emissions intensity through flaring reductions and facility optimizations. We expect to achieve a 30 percent reduction to our GHG emissions intensity this year compared to last year—compared to 2021, and believe that we can achieve our 2030 reduction target as early as next year. We'll provide a progress update along with an updated long-term target in due course.

With that, I'll turn the call over to Jodi.

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

Thanks, Wade. I'm going to start with our price realizations.

In the Bakken, our realized oil price differential was $0.71 per barrel below WTI in the quarter. This was modestly weaker than our prior estimate and reflected lower prices for crude oil delivered into markets in both North Dakota and the U.S. Gulf Coast due to weak U.S. refining margins early in the quarter. However, U.S. refinery utilization recovered later in the second quarter, supported by resilient domestic product demand, and therefore on a full year basis, we expect our average Bakken oil price realization to be at par with WTI.

In the Marcellus, our realized natural gas price differential was $0.68 per Mcf below NYMEX, largely in line with our expectations and we continue to expect a full year differential of $0.75 per Mcf below NYMEX.

Our NGL realizations weakened in the second quarter, averaging just above $15 per barrel and include a significant propane component. Benchmark propane prices decreased considerably during the second quarter due to the strong U.S. domestic production growth that drove inventory levels well above the five-year average.

Ultimately, we generated $197 million of adjusted funds flow in the quarter. With capital spending of $181 million, our free cash flow was $16 million. Notwithstanding this lower free cash flow, our return of capital in the second quarter was $67 million, including $55 million of share repurchases and a quarterly dividend of $12 million. This resulted from accelerating a portion of our second half free cash flow into the first half of the year in order to level load our return on capital throughout the year. However, as Ian mentioned, we have increased our return on capital for the year and plan to return at least 60 percent of our second half free cash flow, resulting in over 70 percent of free cash flow returned during 2023 on an annual basis.

Current tax expense came in at $3.5 million in the second quarter, and we've lowered our full year current tax expense guidance to 3 percent to 4 percent of adjusted funds flow before tax to reflect the lower commodity pricing environment so far in 2023 compared to previous estimates.

Lastly, we narrowed our capital spending range by $10 million to $510 million to $550 million. Previously, it was $500 million to $550 million. A significant factor influencing our capital range is our Bakken non-op activity, and we've seen a fairly material amount show up so far this year. Ultimately, with the non-op activity levels we are seeing, we don't think it's likely that we will hit the bottom of our capital range at $500 million, so we lifted the bottom to $510 million.

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. (Operator instructions).

Your first question comes from Jeoffrey Lambujon with TPH & Co. Please go ahead.

Jeoffrey Lambujon — Analyst, TPH & Co.

Good morning everyone and thanks for taking my questions.

My first one, maybe first few are just from the really strong performance at Little Knife. I know you’ve all spoken to wells in the program there this year being highly competitive against what we've seen from you all in recent years from (inaudible), but just looking at the outperformance relative to the type well in your slide deck it really stands out, so I was hoping to ask a few on this one.

On the type curve and performance specifically, can you give us some context as to what was used to formulate that type well shown there in the charts, whether that's mainly reflecting productivity that you've seen from offset operators through the years there, if there's any risk in your adjustments to think about?

Then in terms of the performance, are there any factors that you'd point to as key drivers behind the productivity that you're showing there and that looks to sustain there as wells have continued to produce. Then I've got a follow-up on the long-term plan.

Ian Dundas — Chief Executive Officer, Enerplus Corporation

Thanks for the question, Jeoff. Maybe we'll hand that over to Wade to sort of give people some context on where the type well came from and other key drivers?

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

Good morning. Thanks for the question, Jeoff.

That type curve that we've had out there not long after the acquisition has been based on the offset producing wells that mostly are to the east of our acreage position. We certainly had a set of producing wells on the acreage that we purchased, but most of those wells have been online for 5-plus years and so those weren't really the anchor for the type curve, but they certainly had a bit of an influence.

So again, type curve based on analysis of a broad set of wells in that greater Little Knife area and certainly is an aggregate of those. Some wells obviously produced a lot more than that, some less than that, so ewe didn't really feel like it was a heavily risked type curve. We thought it was fairly representative.

Even though the early results from these two pads look a lot stronger, time will tell what the ultimate shape of the well performance is. What's clear though is that the early production performance has been better than what we thought it would be, better than, say, the average offset well used in the type curve. We're clearly quite encouraged by that.

The spacing that we've used in these first two pads is at the upper end of our six to nine well range. Both of these pads are spaced in the 9 to 10 well range, and so we're encouraged by the early performance of both the Middle Bakken and Three Forks wells that we've drilled in these units.

In terms of key drivers, ultimately, we would say that the rock properties are really great quality in the area of the two pads we drilled. We think that's fairly representative of that part of greater kind of northern half of our Little Knife area.

In terms of the stimulation approach, there's nothing materially new or novel there relative to what we've been doing this year in Fort Berthold. Our completion design continues to evolve over each year, but broadly speaking, we applied our standard completion recipe, standard kind of flowback recipe to these wells. As you said, quite encouraged by the early performance.

Jeoffrey Lambujon — Analyst, TPH & Co.

Okay. Perfect. That's great colour. Then on the long-term plan, can you speak to what the five-year outlook assumes on productivity out of Little Knife? If the type well shown in the deck is what's embedded in the outlook there, if there are changes year-to-year in the guide to be mindful of?

Then a somewhat of a follow-up to what you just mentioned on changes over time, variability over time, can you comment on your outlook for productivity as far as the near-term program in the Little Knife and just really the running room of wells that could have this level of performance? Thanks.

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

Yes. The underpinnings of that five-year plan, you should think about those type curves that we've shown in the appendix of our decks as the basis for that long-range plan.

Now, we update those on a fairly continuous basis based on well productivity from our own operations and from offset operators. But today, those type curves would form the basis for that five-year outlook.

In terms of Little Knife activity over the next five years, you should expect that it will continue to be an important part of our program each year. You've mentioned kind of competitiveness with Fort Berthold in your first question. As you can see from our type curves and even from our recent performance, we think the acreage we have in Little Knife competes on par quite strongly with the best of our best acreage in Fort Berthold.

Jeoffrey Lambujon — Analyst, TPH & Co.

Okay. Great. Appreciate the time.

Operator

Thank you. Your next question comes from Patrick O'Rourke with ATB Capital. Please go ahead.

Patrick O'Rourke — Analyst, ATB Capital

Good morning guys and congratulations on the dividend increase, and a solid quarter overall. Just kind of wanted to ask a couple of questions here, the first with respect to sort of view on the optimal capital structure and leverage here.

Obviously, net debt went up a little bit in the quarter, but I would infer from only a, call it 70 percent payout ratio, it comes down over the next few quarters. You're under a quarter turn debt to cash flow, so sort of where are you comfortable at current commodity prices? Where do you think it's optimal? Then how does that play into the potential for further return of capital beyond 70 percent going forward? I know you've talked about some of the puts and takes on that in the past.

Ian Dundas — Chief Executive Officer, Enerplus Corporation

Good morning, Patrick.

Let's talk about optimal capital structure. I think it's a general rule, less debt is better than more debt. Having a clean balance sheet, if you start looking at the flexibility, the optionality and what it means to the resilience of the business, I think a whole bunch of things point in that direction. The last few years, sometimes people run hotter balance sheets when debt's been inexpensive. Debt isn't free now, so I think people are paying more attention to that. So for us, very comfortable, continuing to pay down debt, comfortable going debt-free. You saw that last quarter. That strong balance sheet gave us flexibility to actually use the balance sheet a little bit to on a very temporary basis, support the return of capital plan. Now obviously, that's not a long-term plan. When we think about our return of capital framework, sustainability is the key word, the keyword that underpins it. If we get to a position where we're debt free, could that directionally put higher upward pressure on return to the capital plans? It could possibly. We won't have any debt to pay down, as an example, as a competing capital allocation choice, but the business is going to dictate how much capital we can sustainably return, have a sustainable business and continue to grow the business. Hopefully, that gives you a framework there.

We chose 60 percent originally because it was something that sort of made sense to us where we could generate free cash flow and pay down debt and it has worked really quite well through multiple cycles. Obviously, if we end up in a stout price environment and costs remain somewhat in check, you could see upward pressure on those payouts, or opportunities on payout.

Patrick O’Rourke — Analyst, ATB Capital

Okay, that's terrific. Maybe kind of moving over to the asset side of the equation, I think you guys did a great job unpacking sort of what's going on at Little Knife.

Maybe shifting over to those refracs, curious with respect to those wells how they would be currently booked and what sort of—I know it's early days, but how the refrac would look from a reserve bookings perspective. Would it be an acceleration of EUR, or would it be incremental, and how that sort of evolves in your five-year plan as well.

Ian Dundas — Chief Executive Officer, Enerplus Corporation

I'll hand that to Wade to give you some colour on how we're thinking about refracs and/or potentially just redrilling some of these units. Wade?

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

Yes. Thanks, Patrick. In terms of reserves, these wells that we've refracked certainly were in our system as producing wells. But the reality is they look like they have fairly low recoveries relative to other wells. Then even when you zoom out to the unit they're in, that whole unit looks like it's pre-refrac going to recover quite a bit less than what a normal unit would; hence, the motivation to put some more capital in those units. Today, we're testing refracs. It may be in some units, we decide to put more wells in those units.

But in terms of your reserve booking question, once we get a little bit more run time on these wells, any of the incremental recovery that we think we've achieved, that will essentially be a new reserve booking.

Then in terms of just a little bit more colour, today the early performance has been solid. The wells have reasonable initial production rates. We've been pleased to see the rates have hung in there, at least over the first 30 to 60 days. It's really important, though, for us to monitor those for another three to four months and that will really determine how truly economically competitive they will be. It's a pretty high bar for them to compete with the economics of a new well, but we still see the value in these as we leave them in our operational plan each year, provide some flexibility around how we run our pressure pumping crews and execute our annual program.

Patrick O'Rourke — Analyst, ATB Capital

Okay. Great. I might be the only person in the world that cares about these sorts of things, but given the wells or PDP, would they go into the bookings as extensions or as technical revisions on the positive side?

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

I'm not sure. I mean you've got to actually add the capital that you spent in, and so we'd have to get back to you on a specific technical answer to that question.

Patrick O'Rourke — Analyst, ATB Capital

Okay. No problem. Thanks very much.

Operator

Thank you. Your next question comes from Greg Pardy with RBC Capital Markets. Please go ahead.

Greg Pardy — Analyst, RBC Capital Markets

Thanks. Thanks for the rundown. Maybe just staying on the operating side of things, if we pivot over to Williams County, I'm just interested in what your level of activity and plans are there. Then I guess the other question is just the suitability of three-milers up in Williams. Any colour there would be great. Thanks.

Ian Dundas — Chief Executive Officer, Enerplus Corporation

Morning. Good morning, Greg. Wade, do you want to give Greg a bit of perspective on how we're thinking about the area?

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

Yes. In terms of activity, Greg, we actually have recently completed and brought onstream five wells in a pad on the eastern edge of our Williams County acreage. So some of those are included in the Q2 count and some will be in the Q3 count. We'll be able to give you an update on the performance of that pad next quarter. That's the only operated onstreams for the year planned in Williams County.

I think that ratio that you're seeing, kind of one pad for this year, you can think about that as potentially a proxy for what the next four or five years look like. We see that Eastern Williams area as—if you actually dive into the type curves we've got noted in the appendix of our decks—actually compete fairly well from an economic perspective with Fort Berthold and Little Knife. So I think you will continue to see us allocate some capital there.

One of the real important keys to that area in terms of unlocking more and more of the acreage as you move into kind of the central part of our acreage and then even to the western edge of our acreage, there is likely going to be three-mile techno. We're fairly confident that we can execute that kind of a technical program. What we've been working on is working through unit conversion, permitting to be able to change the previous original development in that area, which was mostly two-mile development into three-mile development. So yes, stay tuned on the progress we're able to make there.

Greg Pardy — Analyst, RBC Capital Markets

Okay. Then just to be clear then, the five wells that you would have brought on in the Eastern edge, those are just all standard two-milers.

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

That is correct.

Greg Pardy — Analyst, RBC Capital Markets

Okay. Thanks very much.

Ian Dundas — Chief Executive Officer, Enerplus Corporation

You're welcome.

Operator

Thank you. (Operator instructions).

Your next question comes from Jamie Kubik with CIBC. Please go ahead.

Jamie Kubik — Analyst, CIBC

Good morning and thanks for taking my questions here. Maybe just staying on the asset side of things here. Just can you shed a bit of light on the declines seen in the Marcellus in the quarter? I appreciate that it's a non-operated asset, but can you just add some colour around what's happening there on the decline side?

Ian Dundas — Chief Executive Officer, Enerplus Corporation

Yes, Jamie. It’s I'd say as per plan, as per forecast. Very little capital being spent on the asset, which is we're talking 2 percent to 5 percent of our total capital, so it's rounding to zero. Very, very few onstreams coming on, so we're seeing the decline profile off of the onstreams came on late, late in the year. As we think about the profile of the assets over the year, we think that the declines can start to moderate and sort of flatten out towards the end of the year.

When does it grow again? I guess as per gas price, I guess, that will sort of dictate the activity of the operators driving out there. I don't know if there's any more colour you're looking for, but it's sort of as per expectations now.

Jamie Kubik — Analyst, CIBC

Okay. No, that's helpful. Then you do talk about variability at Little Knife in the Bakken and the mapping contours that you have in your slide decks would point to possibly weaker well results as you drill further south. But do you expect that, that holds based on what you've seen so far, just given the strength in the northern part of the acreage? Can you just talk about how you expect it to vary as you delineate further parts of it?

Ian Dundas — Chief Executive Officer, Enerplus Corporation

Wade, do you want to provide a little more colour commentary there?

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

The most important geologic trend from north to south in Little Knife, Jamie, is that in the northern half, approximately, it's fairly clear that the Little Knife or that the Three Forks reservoir interval is not only quite productive, but also makes sense from an overall unit development perspective to include in the original development. I think you'll see if you look at offset operators, you'll see our operations will include Three Forks locations in each of those units we develop.

What's not as clear is as you move to the far south end of the acreage is, is it the optimal development approach to include Three Forks or not? That's the biggest technical question still out there.

In terms of actual well productivity, as we track offset production right along the eastern edge of our Little Knife acreage, we still see very strong Middle Bakken well productivity and Three Forks well productivity all the way through kind of the central portion of our acreage and the bit of well control that we have on the far south still looks solid, strong.

I don't know that we have a model that says the Middle Bakken will degrade in productivity, but we probably don't have as much well control at the far south end as we do at the north end.

Jamie Kubik — Analyst, CIBC

Okay. That's good colour. Then maybe just on the capital allocation side of things, debt reduction or debt levels at the range that they're at right now and then greater than 70 percent of free cash being returned to shareholders, as you guys mentioned, but how are you thinking about M&A and potentially adding additional inventory into your business? Can you just outline how you're thinking about that?

Ian Dundas — Chief Executive Officer, Enerplus Corporation

Thanks for that question, Jamie.

On some levels we're always thinking about it. We've got capability and financial capacity that gives us a lot of flexibility to add to the portfolio. When you look at the portfolio, there's no real holes in it. We've got ample inventory and everything we're thinking about bringing in, we think about how it's going to compete with what we've already captured, so the bar is probably higher than it has been in other years relative to that question.

For us, anything in North Dakota we pay attention to. At the core, we're looking for accretive activity that's going to bolster our NAV and build out that business and make money for people.

How do that in the context of this moment in time in the market? There haven't been a lot of deals out in North Dakota. There have been some. We would characterize as a lot of those as being relatively competitive. People that don't own Bakken typically want to own more of it or want to get in there, and it's a place where you can get some really good low-risk black oil.

So, I guess I'll sort of leave it with a final comment. The bar is higher than it's been before for us to do activity, but we're certainly in a good position if we saw something trade that can make our business better and make money for people.

Jamie Kubik — Analyst, CIBC

Okay. Thank you for that. That’s all for me.

Operator

Thank you. At this time there are no further questions. Please proceed with your closing remarks.

Ian Dundas — Chief Executive Officer, Enerplus Corporation

All right. Well, we appreciate everyone calling in on this last couple of weeks in the summer. Have a great rest of your week and maybe we'll see you in the fall. Thanks, everybody.

Operator

This concludes your conference call for today. You may now disconnect your lines. Thank you.