



HUSKY ENERGY

THIRD QUARTER 2018 CONFERENCE CALL TRANSCRIPT

Date: Thursday, October 25, 2018

Time: 9:00 AM MT / 11:00 AM ET

Speakers: **Robert Peabody**
President and Chief Executive Officer

Jeff Hart
Acting Chief Financial Officer

Robert Symonds
Chief Operating Officer

Jeff Rinker
Senior Vice President, Downstream

Dan Cuthbertson
Director, Investor Relations

OPERATOR:

Please see the Advisories appearing at the end of the Company's October 25, 2018 earnings press release.

OPERATOR:

Welcome to the Husky Energy Third Quarter 2018 Conference Call and Webcast. As a reminder, all participants are in listen-only mode and the conference is being recorded. After the presentation, there will be an opportunity to ask questions. To join the question queue, you may press star, then one on your telephone keypad. Should you need assistance during the conference call, you may signal an Operator by pressing star and zero.

I would now like to turn the conference over to Dan Cuthbertson from the Investor Relations Group. Please go ahead, Mr. Cuthbertson.

DAN CUTHBERTSON:

Thanks, and good morning. With me today are CEO Rob Peabody, COO Rob Symonds, CFO Jeff Hart, and other members of the Management Team. After we discuss our third quarter results, we'll take your questions.

The call will include forward-looking information. The advisories in this morning's news release and in our annual filings on SEDAR and EDGAR describe the associated risk factors and assumptions.

All the numbers are in Canadian dollars and before royalties, unless otherwise indicated.

Our Investor Relations Team will be available after the call to answer any specific modeling questions.

Now, over to Rob Peabody to start the call.

ROBERT PEABODY:

Thanks, Dan, and good morning. As you see from our results, we delivered another strong quarter with a substantial increase in funds from operations and in net earnings, compared to the same period a year ago. Our strategy continues to prove itself. Our integrated model, combined with our high netback Offshore business, is generating increasing funds from

operations and free cash flow. In addition, our net debt metric are now 0.6 times annual funds from operations, which is well below our target.

Before we get into details on the quarter, I'd like to speak to the offer we made to acquire all the outstanding shares of MEG Energy. This transaction will create a stronger Canadian energy company, offering numerous advantages to both MEG and Husky shareholders. MEG shareholders will receive a substantial premium with immediate cash value and upside potential in the combined company. The deal will immediately meet and exceed the 2020 financial targets MEG set for itself, while advancing our own five-year targets.

One of the things we've learned over the past 80 years, if you're going to be a successful heavy oil or bitumen producer in Canada, you need to have a high level of integration. The combined company will deliver production of more than 410,000 barrels of oil equivalent per day, with about 375,000 barrels per day of combined heavy processing, upgrading and committed transportation capacity.

Three items to highlight: First, utilizing our strong balance sheet and low-risk profile, the combined company will deliver substantially more free cash flow per share. This can be used to increase cash returns to shareholders and reinvest in a rich portfolio of low-cost, higher margin projects. Second, we expect to maintain our investment grade credit rating. Third, it gives MEG shareholders a lower cost of capital and an opportunity to participate in Husky's quarterly cash dividend.

Husky is uniquely positioned to deliver strong value to MEG shareholders. The combined company's production will have access to our extensive export pipeline network, our refineries and our upgrader, which insulate us against location and quality differentials. In short, we can immediately deliver the value MEG shareholders were looking for over the next few years, but with significantly less risk. We are confident the proposed MEG offer is in the best interest of Husky and MEG shareholders, employees and stakeholders. We remain prepared to engage with MEG's Board of Directors to complete the transaction as soon as possible. We encourage MEG shareholders to tender their shares.

Now, let me touch on a few highlights from Husky's third quarter.

The benefit of our physical integration was demonstrated again with the majority of our production receiving global pricing. We were essentially unaffected by the wide differentials seen in the quarter. Funds from operations were more than \$1.3 billion, or a 48% increase over last year. Free cash flow was \$350 million. Net earnings were \$545 million, up threefold from a year ago.

On the operations side, production from the Rush Lake 2 thermal project started this month, six months ahead of schedule. We're building these 10,000 barrel a day projects very efficiently. The timeline for Dee Valley has also moved up, with first oil expected in the fourth quarter of 2019, six months sooner than the plan we laid out at our Investor Day in May.

In the offshore, gas demand in China remains strong, and we are making progress advancing the 29-1 Field at Liwan. In Indonesia, the BD Project is consistently achieving our gross daily target, with higher than expected liquids production. In the Atlantic, at the West White Rose Project, the base slab for the concrete gravity base has been completed, work is now underway on the column and the topsides are taking shape in Texas.

In summary, as we advance our portfolio of low-cost, higher margin projects, we continue to deliver on our five-year plan.

Jeff will now take you through our Q3 financial results.

JEFF HART:

Thanks, Rob. Although location and quality differentials widened this quarter, our physical integration eliminated any associated negative impact on our financials. This was due to solid contributions from our upgrader at Lloyd, our U.S. refining and storage capacity, and our ability to send crude to higher value markets through our existing export capacity.

Funds from operations in the quarter were more than \$1.3 billion, driven by two main factors, the Downstream and Asia-Pacific. The Downstream business generated \$580 million in EBITDA, with an additional \$206 million from our Infrastructure and Marketing segment. We took advantage of discounted crude from Midland, using it for about half of our Lima crude feedstock, and we continue to benefit from our 75,000 barrels a day of committed capacity on the Keystone Pipeline. In China, Liwan achieved production of just over 370 million standard

cubic feet per day. Average sales gas prices at this project were CAD\$13.14 per mcf, with liquids pricing averaging \$76.13 per barrel. EBITDA was \$781 million, with netbacks of \$65.45 per boe.

I'd point out the \$1.3 billion in funds from operations doesn't include any business interruption insurance related to the Superior refinery. During the quarter, we accrued proceeds of \$110 million for asset damage and repair costs, which we expect to collect in the new year. While we haven't yet accrued proceeds for business interruption, these payments are also expected to begin in 2019.

Our CapEx of \$968 million was largely directed toward our series of Lloyd thermal projects and the West White Rose project, and we expect to end the year with capital spending of approximately \$3.3 billion, due to our increased working interest in the 29-1 Field and the additional drilling we undertook in Western Canada on our oil and liquid rich plays.

Free cash flow was \$350 million in the quarter and \$1.1 billion year to date. We continue to return cash to shareholders, with the Board approving a quarterly dividend of \$0.125 per common share.

We exited the quarter with net debt of \$2.6 billion, including \$2.9 billion in cash, representing 0.6 times net debt to trailing 12 months' funds from operations. We also had \$4.3 billion in undrawn credit facilities.

In terms of operating costs, total Upstream operating costs in the quarter were \$14.68 per boe, compared to \$14.12 per boe a year ago. This increase is due, in part, to lower production in the Atlantic region, which has a large fixed cost component. Our overall operating netback was \$31.30 per boe. For our thermal production, op costs averaged \$12.04 per barrel, resulting in a netback of \$30.63 on barrels from Lloyd, Tucker and Sunrise. In the Downstream, we realized margins of \$29.19 at the upgrader, and our U.S. refineries realized margins of US\$17.52 per barrel, which included a pre-tax FIFO loss of US\$0.34 per barrel. Our Lloyd Value Chain netback for heavy oil production was \$55.21 per barrel, a 50% increase over \$36.87 per barrel a year ago, and this demonstrates that even with the wide heavy differentials, we are receiving global pricing, as are other segments of our portfolio.

Before I hand it over to Rob Symonds, I want to say a few words about the proposed MEG transaction. The balance sheet of the combined company will remain strong, with net debt at the end of 2019 expected to be approximately one times 2019 funds from operations. We also expect to maintain investment grade credit ratings. The MEG deal is accretive across the board to free cash flow, funds from operations and earnings. The combined company will have \$200 million in annual financial, operational and other synergies, resulting in additional free cash flow. This acquisition will build on the progress we've already made in lowering the oil price needed to break even on earnings.

Thanks. Rob Symonds will now update you on our operations.

ROB SYMONDS:

Thanks, Jeff. Production averaged 297,000 boes a day in the quarter and will be coming in at around 300,000 to 305,000 boes a day for the full year. This is due to several factors, including maintenance on the once-through steam generators at the Sunrise energy project. We've also slowed the pace at CHOPS well optimizations. We're replacing this production with third-party barrels impacted by the differential, running them through our refining and transportation system. There was also a five-day impact at Liwan due to the super typhoon Mangkhut, which passed directly over the platform, but did not cause any damage. In the Atlantic, we're still working to address the high water cut at a recent infill well, resulting in weaker than expected production in that region. We expect to exit the year with production at around 320,000 boes a day. We've provided detailed guidance information on our website.

Rush Lake 2, which began production earlier this month, is now contributing to the Integrated Corridor. It is currently producing about 3,000 barrels a day and is on the way to ramping up to its 10,000 barrel a day capacity by the first quarter of 2019.

Dee Valley is coming along very much like Rush Lake 2. We now expect to see first oil before the end of 2019, which is six months sooner than we anticipated at Investor Day. Modules have all been delivered to site and the once-through steam generators have been assembled. Work on the mechanical and electrical systems is underway, and building construction has begun. Drilling on the second well pad is completed. We're really hitting our stride with these projects. The modular design is contributing to efficiencies and improved construction timelines.

Work at our other thermal projects is also progressing nicely. At Spruce Lake Central, drilling on the first well pads was completed during the quarter and construction of the central plant is underway. First oil is set for 2020. At Spruce Lake North, site clearing is underway, with first production expected around the end of 2020. We continue to progress two additional previously sanctioned thermal projects, with the goal of being on production in the second half of 2021. So, in addition to Rush Lake 2, which is now online, we have another 50,000 barrels a day of production in the queue from thermal projects over the next few years.

Turning to Tucker, we completed a three-week turnaround in the quarter and are now ramping back up. In fact, just three weeks after restarting, Tucker has hit peak daily rates of over 30,000 barrels a day.

At Sunrise, we told you last quarter that production would be flat quarter-on-quarter, and gross volumes averaged 49,400 barrels a day in Q3, reflecting steam limitations due to the maintenance on the once-through generators. Nine out of 10 generators are currently running and all 10 will be back online later this quarter. Sunrise is currently producing about 53,000 barrels a day. We still have the 10 infill wells drilled earlier this year to come on later this quarter.

As one of the top in-situ thermal producers, we see MEG's assets complementing our existing portfolio and further strengthening our Integrated Corridor business, adding quality, low-cost production. MEG's Christina Lake development will be an excellent fit. It has consistently produced above its design capacity and below its design steam/oil ratio. One of MEG's greatest strengths is its people, the operational expertise of its employees and their proactive approach to technology and innovation of valuable assets. Together, we can apply our combined expertise across a wider set of top-tier properties.

Now, taking a look at our Resource Plays, we accelerated our drilling program in the Ansell and Kakwa areas, going from an 18- to a 25-well program. Fifteen wells have been drilled to date and 13 completed. In the Montney formation, four wells have been drilled in the Wembley and Karr areas, with three completed. This is part of a program of up to eight wells in the region this year.

Turning next to the Downstream business, total throughput averaged 351,000 barrels a day. This included the impact of the turnaround at Lima which started in mid-September. We'll also be doing work related to our Crude Flexibility Project during this turnaround, which will allow us to process up to 40,000 barrels a day of heavy by the end of next year. Lima and Toledo averaged 234,000 barrels a day. Canadian refining and upgrading throughput was about 117,000 barrels a day, with EBITDA of some \$240 million. In the U.S., gasoline, diesel and jet fuel sales were about 200,000 barrels a day. At our Superior Refinery, work to winterize the site is underway. We have appointed an engineering contractor to oversee design work for the rebuild. We anticipate normal operations will resume some time in 2020.

In the Offshore, as mentioned earlier, strong demand in China was reflected in sales gas volumes at Liwan of 370 million standard cubic feet per day, and this included a five-day production impact due to the super typhoon. The BD Project is consistently achieving our gas sale targets of 100 million standard cubic feet per day and are generating higher liquids production. Turning to the Atlantic, the base slab for the West White Rose Project has been completed. The focus is now on building up. Slipforming for the column started a couple of weeks ago and we expect to hit 46 metres, almost half the length of a football field, before pausing for the winter. We will then resume the concrete pour in the spring. At the same time, construction of the topside is underway in Ingleside, Texas, and is about 10% complete, and work on the living quarters in Argentia, Newfoundland, is about 45% complete. North of the White Rose Field, we're evaluating the results of the successful A-24 exploration well and we plan to spud an exploration well south of the field by the end of this year.

All in all, we're making steady progress on all of our projects, while our Downstream business continues to deliver strong financial results.

Thank you. Now, back to the Operator and we will take your questions.

OPERATOR:

Thank you. We will now begin the analyst question and answer session. Any analyst who wishes to ask a question may press star and one on their touchtone phone. You will hear a tone to indicate you are in queue. For participants using a speakerphone, it may be necessary to pick up your handset before pressing any keys. If you wish to remove yourself from the question queue, you may press star and two. One moment, please, while we poll for questions.

Our first analyst question is from Prashant Rao from Citi. Please go ahead.

PRASHANT RAO:

Good morning, and thanks for taking the question. I guess I'll start with the MEG M&A bid and maybe take it head-on. I sort of wanted to ask about the background environment for consolidation in Canada, both in terms of this deal, in terms of how competitive you could see it becoming, or some of those dynamics from perhaps third-parties who would be interested in MEG assets. Then, just more broadly speaking, are we seeing the start of a broader consolidation wave within the Canadian energy play, and how, maybe with some color on that, as to where we are in the pricing cycle for Canadian heavy?

ROBERT PEABODY:

Okay, this is Rob, Rob Peabody. I guess, just broadly on the bigger picture, I'd just say that I see this deal as relatively unique because of the way these assets fit together with our Midstream and Downstream and add to the whole integrated play. As I said in my comments, you know, we've been in the heavy oil/bitumen business for about 80 years one way or another as a company, and one of the things we've noticed is pure play Upstream heavy oil/bitumen companies can work when they're small, but at a certain scale they tend to ultimately have to become integrated. If you look at the major companies in the Oil Sands now in Alberta, the vast majority of the production is now produced by a number of companies that are integrated and that is their model. Husky happens to be the most integrated. That means adding some additional Upstream production kind of is most applicable to us, I guess you could say. So, I think we're pretty unique in the way we can add value through this transaction. I can't comment on others' intentions, but I think most of the peer companies that I've heard talk are kind of just focused on improving operations and had done some previous A&D that they're still in the process of sort of working their way through. So, whether it's the start of another one, I don't know, but I guess I would just focus on the fairly unique aspects of this deal.

PRASHANT RAO:

Thanks, Rob, I appreciate that, and just one follow-up then on the heavy oil pricing, sort of a two-parter. One, your price realization there was—at least from where we expected versus

where the market—was a bit stronger, and so wanting to know is there anything we should be reading into that in terms of what you might be doing, levers you might be pulling for stronger price realization on your heavy production. Then, two, just broader thoughts on—we've seen a blowout, obviously, related to the refining maintenance season here in the United States and expect that to contract back, you know, in terms of differential, as we get through Q4, but, structurally speaking, how does the roadmap look from here and what's really needed to move a differential to where it's something that's a bit more stable, as you look out to the first half of 2019?

ROBERT PEABODY:

Okay, I think—I don't know exactly your before and after calculations on the heavy oil realizations, but one of the advantages we have in Lloydminster is the way we run our heavy oil production into our integrated Midstream and upgrading facilities, which—and, frankly, they're closer to market than some other suppliers. Just optimizing that whole picture, we can generally, between quality and logistics, get a little higher sort of netback than average, I guess.

In terms of the differential and outlook for that, I think we can say it's going to be absolutely volatile, that's one thing, and standing back from it a little bit, I would just say that I know there's been a lot of refinery outages, which certainly is contributing to the big blowout in the differential, but I still think pipelines are the key driver in that, and I'm not as optimistic as some you're going to see major relief on that just because of the refinery turnaround season changing. I think, if the oil can get down there, it's still being processed. The problem is it can't get down there. Given those constraints, I think we're really looking for some relief with rail capacity first, probably next year, helping. I don't know if that'll help the absolute differential. It'll help some producers get a little better margin. Then, with Line 3 coming on, if enough people get onto the rail, then I think by the end of next year, with Line 3 coming on, then you might see a little bit more relief. Again, the numbers would suggest by the time that comes on we still have a kind of a net too much production coming out of Western Canada.

So, even as we studied this MEG deal, we have taken a fairly—I guess you could call conservative, but we are assuming that high differentials continue, certainly, the rest of this year, all of next year, all of the year after that, and then we start seeing some structural relief from some of these pipelines, if they come on according to the kind of current schedule, which, for the close industry watchers, you'll know is always a very uncertain expectation, they've

tended to go backwards, but I'm hoping that XL, probably the next option after Line 3 gets debottlenecked, will come on, maybe a little later than its current plan, but hopefully will still come on in that sort of timeframe, so we start seeing some relief somewhere out in the two- to three-year time period.

PRASHANT RAO:

Okay, thank you for that thorough answer, I appreciate it. I'll turn it over.

ROBERT PEABODY:

Thanks.

OPERATOR:

Our next analyst question is from Paul Cheng with Barclays. Please go ahead.

PAUL CHENG:

Hey, guys, good morning.

ROBERT PEABODY:

Hi, Paul.

PAUL CHENG:

Rob and Jeff, maybe I missed it. Did you comment the reason behind the capital budget increase for this year?

JEFF HART:

Yes, it's Jeff here. Yes, we did. A couple things as we went through script there that we talked about is really we expanded some drilling on our oil and liquids rich plays in Western Canada, and the other factor is the increased working interest on the 29-1 Field in Asia, we had assumed 50% and it's a 75% working interest Husky share now.

PAUL CHENG:

Mm-hmm. Rob, given the recent WCS price, have you guys—I know that you slowed down the Sunrise and CHOPS, but do you have actually any shut-in?

ROBERT PEABODY:

What I'd say there is we're not blowing our brains out to drive production in Western Canada heavy at the moment. It doesn't seem the right environment to be prioritizing volume over sort of netbacks and earnings and cash flow. It's more a case of not pursuing some of the opportunities we might have pursued in other times to avert decline, particularly in things like the cold side of the business and that, where it doesn't make a lot of sense to do that right now.

PAUL CHENG:

Right, but you did not actually go in and shut the well, because, I mean, at \$20 WCS, the netback is probably \$5.00 or so, pretty close to some of your more high-cost, cash variable costs, I would presume.

ROBERT PEABODY:

Yes, some of it is certainly getting close, but we do monitor that carefully and make sure we're not running things at a negative cash margin.

PAUL CHENG:

Okay, and maybe in the Marketing, in your I&M, I was surprised that your third quarter result is not even much better, comparing to the second quarter, given the differential got wider further, so is there any reason why that is not even a better result there?

ROBERT PEABODY:

I don't have anything offhand, Paul. Actually, the result was pretty strong. Probably, we may not have—I don't know, in I&M, like, quarter to quarter, I don't have the number in front of me, but I know it performed very strong in this quarter and continued to deliver in a pretty high—

PAUL CHENG:

Oh, don't take me wrong, yes, a strong quarter, it's roughly about the same as what you did in the second quarter, but the third quarter differential is certainly much wider, so I guess my question is that is there any—

ROBERT PEABODY:

Oh, one thing about that, Paul, is sometimes some of that lags, too, by the way. There's pipes involved and there's—you know, you put the stuff in and it comes out 90 days or 60 days later,

things like that. So, some of the big run-up in differentials that we saw just at the latter part, that'll probably come in the fourth quarter. So, I think that might be the step-change, that you're kind of saying where is that. I think it's probably still in the pipes.

PAUL CHENG:

Okay, and after the MEG, assume that you will be successful, on a pro forma basis, what will be your net exposure to the WCS discount? I mean, you probably will move from a slightly positive benefit to a somewhat negative, but how big is that? Is there any sensitivity you can share?

ROBERT PEABODY:

Yes, I mean, what we're going—again, if you go back to our Analyst Presentation, we're going to have about 400 barrels a day of blend, heavy and bitumen blend, and we're going to have about 375,000 barrels between upgrading, refining and committed pipeline capacity to take that away. So, you're right, we go from where we are today, actually, a little bit short heavy relative to our Downstream and Midstream capacity, to a place where we're about 375,000 or 400,000.

Now, we are, I would point out again—and, of course, this includes the completion of the Crude Oil Flexibility Project at Lima, which, by the latter part of next year, after the turnaround next year, will add 30,000, take it from 10,000 to 40,000 barrels a day of heavy processing capacity there. At the same time, while Superior is down at the moment, modifications are also being made to increase heavy capacity there by 5,000 barrels a day. At the same time, we have other options in our portfolio we haven't yet pulled the trigger on, including the one we talked about before we bought Superior, which is adding an asphalt unit to the upgrader in Lloydminster, which still looks like a good project, but we just have delayed pulling the trigger on that sort of project until we understand how these pipelines are likely to be resolved, and we're hoping we'll get a fair bit of information over the next six to 12 months as to how that whole situation is going to unfold.

So, to your point, we're a little bit short on the Upstream now, we move to be a little bit long on the Upstream post the MEG acquisition, but it's also important, as MEG's pointed out several times, to know that the MEG acquisition does come with some pipeline capacity from Midwest down to the Gulf Coast. You still have to get it to the Midwest, so that would be subject to pro-rating, but there is some credit you can take for that, as well.

PAUL CHENG:

Rob, on the MEG deal, what is the next step or what's the timeline, or is it really nothing is going to happen until January, then you would decide what is the next step?

ROBERT PEABODY:

Well, you know, as far as the MEG deals goes, we feel we've provided a full and fair offer that represents, I think, a great opportunity for MEG to maximize value to get to the targets that they talk about, but at pretty low risk, and we stand ready to kind of engage with MEG at any time they want to, to try to get this concluded even quicker than that process would be, and that's the process, if there's kind of no engagement and we just take it to the final wire and then mid-January there's a deadline for tendering their shares, and that's—so, that's the way it'll play out if there isn't engagement. As I say, we stand ready to engage. We think it's a great offer for both MEG shareholders and Husky shareholders.

PAUL CHENG:

Right. Just curious. It seems MEG came out and rejected it, since then, have you guys had any conversations with them at the Board level, at the C-suite level?

ROBERT PEABODY:

Essentially, you know, we stand ready to engage. That hasn't happened yet. That doesn't surprise me, by the way. I mean, there's a bit of a—I don't want to say "dance," but there is a little bit of things that go on in these things. It is incumbent, I'm sure, on their Board to understand if there's any potential for competing offers, or anything like that, before they move forward down the process. So, we're ready to talk to them whenever they're ready.

PAUL CHENG:

Thank you. Then, just a quick one. Maybe tomorrow, either you or someone from your team, can you give me a call. I'm still not sure I fully understand how the \$70 million of the synergy benefits with MEG is going to be unique, so if someone can walk me through that, that's great. Thank you.

DAN CUTHBERTSON:

Yes, no problem. That's a question we get quite often. So, we'll get back to you with some specifics there.

OPERATOR:

Our next question comes from Matt Murphy with Tudor, Pickering, Holt.

MATT MURPHY:

Good morning, and thanks for taking my question. On the conventional heavy side, obviously quite challenging in the current environment, as we've talked about. I'm just wondering how we should think about base declines there. If you guys aren't deploying material capital, is the 20% to 25% range reasonable there?

ROB SYMONDS:

Yes, Matt, this is Rob Symonds. I would suggest that's the right number to use, yes.

ROBERT PEABODY:

Yes, but it's important to say that's the right number to use on the cold production, which is a very small fraction of total heavy production.

ROB SYMONDS:

Yes, if you think about the cold, the cold is about 40,000 to 45,000 barrels a day, so, think about, yes, 20%, 25% on that. I mean, there are some—there's some nuances in there, the horizontals are a little different, but as an overall number, that's a good number for you.

ROBERT PEABODY:

I guess the other thing I'd say is that's the base decline, and while we're not, as I used the word, blowing our brains out on this, we are doing some interventions there, so the decline there, that won't be the decline you see in that production. It's just that we're not doing some of the more heroic sort of stuff you could be doing there.

MATT MURPHY:

Got it, thanks. Then, on Rush Lake 2, you guys mentioned achieving nameplate there in Q1 of '19. I'm just wondering how we should think about your marketing of those barrels given, obviously, current tightness in the system. Are these expected to be sold into the spot market at Hardesty or is there some slack in your system there to allow smoother egress? Thanks.

JEFF RINKER:

Yes, this is Jeff Rinker. I think, as Rob mentioned earlier, we're still, as we sit today, a little bit short heavy oil transportation and marketing capacity, and so we are often buying third-party barrels, so these will just replace third-party barrels that we otherwise would have purchased.

MATT MURPHY:

Got it. Thanks, guys.

OPERATOR:

Our next question comes from Jon Morrison with CIBC Capital Markets.

JON MORRISON:

Good morning all.

ROBERT PEABODY:

Good morning, Jon.

JON MORRISON:

I realize that you're well hedged from the Canadian heavy and light oil differentials, given the matching of your Upstream and Downstream operations, particularly on the physical side, but given that much of the margin capture is largely going to accrue through your Downstream and Midstream assets, how do you think about the optionality that you have around more aggressively curtailing some of your heavy production volumes and just redirecting third-party volumes through those assets, rather than continuing to produce Upstream assets that obviously are at a fairly suboptimal pricing for you guys?

ROBERT PEABODY:

I guess—I mean, Jeff spends lots of time every day thinking about that, and at the margin, clearly, we decided to, you know, as I say, not aggressively work to maintain those volumes while we can do quite well purchasing the third-party barrels, but it is important to also understand that when it comes to all these thermal projects, and things like that, they're not—you just can't turn them on and off without potentially doing some significant damage to the reservoir. So, we take a little more of a long-term view on the way those operate. They're still making some money, not as much as we would like them to make, but we're still able to make some profits, and it's quite important that we don't do anything that negatively affects the

reservoir over the longer term, because these are, of course, extremely long-life assets, they'll be running decades from now. That's what we're optimizing sort of, not damaging anything, and just at the margin kind of optimizing the third-party equity split.

JON MORRISON:

Is it fair to assume that on the CHOPS side, as well, then, when you talk about curtailing everything other than some base workover work, again, it's really just driven by if a well goes offline and you believe it's optimal to bring it back on from a reservoir perspective, that's what underpins the decision to spend that capital, versus just leaving it off until prices improve?

ROB SYMONDS:

Yes, Jon, this is Rob Symonds. There's a lot of pieces that go into that. Indeed, there's a reservoir piece, but we also do have quite a fixed cost basis on some of these assets, you need to be careful that you don't shut it in. Unless you can get rid of the fixed costs, you don't necessarily improve your situation. So, we're very deliberate on each one, looking at the cash income associated with those. But, I think, to Rob's point, the philosophy is not going to change, and the philosophy is we're not changing heavy oil production in this environment.

JON MORRISON:

That's helpful. Can you talk just at a high level about your broader appetite to try to manage the diff from an industry perspective, and if we were to start to see the industry broadly taking steps to try to improve supply and demand out of Canada, is that something that you guys would be willing to participate in, and does it become more important as you think about internalizing those MEG volumes as you get closer to the transaction closing, should it go forward?

ROBERT PEABODY:

Sure, I can talk to that. I mean, first and foremost, I've heard some people talk about this as being a bit of a market failure. I think this is anything but a market failure. The market's doing exactly what you'd expect it to do and it's doing the right thing, it's trying to clear the market. The failure is in a whole bunch of other parties, including the industry, we'll put everybody in the same bucket, who haven't taken appropriate action to head off what has been probably the slowest train crash, or something, I've ever seen. Coming from about 10 years out, you could see it coming, and yet we walked right into it as a nation. So, a pretty sad statement on Canada.

But, you know, we're committed to being—we're a committed, I guess you could say, capitalist-free enterprise company, and we think the right answer to these sort of problems are market-based solutions. Now, clearly, if we do nothing, what'll happen is the market will continue to clear and, frankly, I suspect the differential will come in a bit from where it is today eventually, because people will start shutting in that have the highest sort of production costs and really have no choice, and when enough people shut in, the differential will come back to some equilibrium point that allows people to—the remaining people to continue to produce profitably, or at least just profitably.

So, I think that's certainly our philosophy and we're not planning to do—we certainly wouldn't support anything that's not a market-related solution. Now, one market-related solution, I think that I could support, maybe with a—because, in the broadest scheme, I think it would work for both the industry and government, is the idea of trying to get some additional rail capacity in, in the near term, because, frankly, the government will make a really good return on that if they do it, because they're also losing out on royalties and taxes, and things we need to build hospitals and schools, and things. So, I think it is a useful thing to consider. It has merits there even for the government, because they can actually create a return around the investment, and, certainly, from industry investing in some of that makes a lot of sense, too.

JON MORRISON:

That's helpful, and obviously I don't view it to be industry's doing. However, unfortunately, they're set to resolve the problem that they didn't necessarily create. Can you just talk broadly about the trends you're seeing in the Canadian oil storage market right now? Because, obviously, apportionments are high, that's causing the diff to blow out, but third-party data would show Canadian storage actually declining in the last month. Is your view that those barrels are just moving into private storage, isn't captured in some of the data that we can see, or what do you think is going on in the Canadian storage market right now?

ROBERT PEABODY:

Do you want to talk to it, Jeff? I don't think we have a strong view on that, to be honest. I mean, our sense is Canadian storage is filling up, that's our sense, but I don't have hard data on that. I'm actually surprised if the hard data is suggesting that it's emptying out. Did you have anything you want to add to that?

JEFF RINKER:

I can only comment on what we're doing. We're finding it, obviously, very useful right now to have contracted storage that we have, because this gives us—you know, assets give you optionality, right, and being able to achieve actually improved value, even compared with what the index-to-index prices would suggest, having access to dedicated storage capacity, obviously, is a key to that, and so we're finding having the storage capacity we have in Hardesty, in particular, is very useful right now in the current market environment.

JON MORRISON:

Last one just for me. Just in terms of the acceleration of the drilling program on the NGL side, is it fair to assume that the decision to dial up the program is largely driven your need to fill the Corser plant or was it largely wellhead economics and rates of returns telling you that it still makes sense to be more active there than you were originally thinking?

ROB SYMONDS:

Jon, it's not specific to the Coarser plant, it's very much about liquids, in a number of areas. The Ansell area is one. We're looking at the whole Spirit River STACK, looking for a bit more liquids, not necessarily always the Woolwich. Likewise, Kakwa. Wapiti, again, we're actually going for an oil play, not so much liquids rich in Rainbow. So, increased drilling is—now we have an opportunity, rig continuity is always helpful for us to keep the good rigs that we have running, and so we're having an active fourth quarter and we'll see the benefits of that primarily into Q1 of next year.

JON MORRISON:

I appreciate the colour. I'll turn it back.

OPERATOR:

Our next analyst question is from Mike Dunn with GMP FirstEnergy.

MIKE DUNN:

Thanks. Good morning, gentlemen.

ROBERT PEABODY:

Good morning, Mike.

MIKE DUNN:

Good morning. Most of my questions have been answered, just maybe if I can, on the non-thermal heavy/medium oil, production guidance is down for the year. I was surprised that, given the activity reduction, the cap ex guidance wasn't reduced. Are there other projects going on not related to production that caused that guidance not to go down?

ROB SYMONDS:

There's obviously a base level of maintenance, tanks, and so on, that's in there. There is some incremental capital going into a polymer flood that we haven't slowed down as a result of this, because that polymer flood won't come on until next year, and obviously that's the primary reason why you don't see a capital reduction.

MIKE DUNN:

Sure, great, and then maybe if one of you gentlemen could walk us through maybe—I think, conceptually, we get it, but with regards to how many barrels you can nominate on, let's say, the Enbridge Mainline System and how you benefit from being able to nominate as both an Upstream producer and a Downstream refiner, are you essentially able to nominate the majority of your refining capacity in terms of volumes, so that when you get apportioned on all of your Upstream and Downstream nominations, you're still getting all your Upstream volumes out?

JEFF HART:

It's Jeff here. There's a couple of factors when you look at our Infrastructure and Marketing segment and Downstream. Number one, I'll comment, is we do have the firm takeaway capacity on Keystone just to hold that, which generates value for us and provides a firm offtake from the Basin. Number two, and you're referring to the Mainline, ultimately, on our U.S. refinery, the access there, we nominate based off of what we can process through on the crudes, and ultimately that gives us Downstream uses that we can nominate to on top of our outlets from Western Canada. So, that's the colour we can really provide on that, but, really, having storage and Downstream infrastructure you can nominate into does help.

JON MORRISON:

Okay. Then, would it be fair to say then, even with, let's say, 40% apportioned on that Mainline, you'd still end up with capacity in excess of your Upstream volumes?

ROBERT PEABODY:

Well, in aggregate, I think is important say, and that's what we've seen in the last quarter, is in aggregate, including the 75,000 that we have on Keystone, including our ability to nominate into the Mainline, and keeping in mind including the fact that we have an upgrader sitting in Lloydminster and a refinery, an asphalt refinery sitting in Lloydminster, where most of those—most of the products, other than the synthetic crude that also goes down the Mainline at one level or another, most of those products say in Western Canada. So, when you put all that together, we manage to handle all our production.

JON MORRISON:

Great. Okay, thanks, that's all for me.

ROBERT PEABODY:

Super.

OPERATOR:

Our next analyst question is from Greg Pardy with RBC Capital Markets.

GREG PARDY:

Thanks. Good morning, everybody.

ROBERT PEABODY:

Good morning.

GREG PARDY:

Just a couple quick ones for me, and this is a just-to-be-sure question, but on the Canadian light sensitivity then, no exposure with you guys, just to be sure?

ROBERT PEABODY:

Canadian, sorry, what?

GREG PARDY:

Yes, Rob, I'm just referring to the light-light, so anything vis-à-vis Edmonton.

JEFF HART:

We wouldn't have really any exposure in Edmonton. I mean, the light production that we do produce, in essence, is the synthetic crude we have coming out of the upgrader, but that would be fundamentally it. We have very little light crude in Western Canada, so you've got the synthetic, and then also, to think about how we manage the infrastructure, as well, is we'll play—it's not just integration, we'll also manage the optionality, and depending what the light crude prices are in Western Canada versus light crude in the U.S., we can balance out with what we'd export on Keystone and balance that out of what would go down to the U.S., as well. So, we can manage both light and heavy exposures with our takeaway capacity.

GREG PARDY:

Okay, terrific, and then just the second one is with respect to Superior. I know you mentioned it'll be back up in 2020, and I know it's a rebuild, but any enhancement there that we should be thinking about with respect to either heavy processing or distillation capacity?

ROBERT PEABODY:

Greg, maybe I'll just—essentially, it's going to be a rebuild of the FCC, fundamentally, and part of the crude unit. Even before this incident occurred, of course, we had a plan in place to increase heavy capacity at the unit. So, that's the major increase in heavy. I think we're also looking at—we may, in the end, find that in the course of the rebuild that there's—you always knew where there were a few bottlenecks in the process, and if a vessel has to be replaced in it and it had a little bit of a bottleneck thing, it's quite a simple thing to upsize the vessel slightly, or something. Of course, all of those things we have to talk to our insurers about, it's very important that we keep them on side with what we're doing. So, we're looking at little things we could potentially do, but we're going to keep them quite little. We're going to fundamentally be looking at replacing in kind, although, you know, clearly, what's replaced will be modern technology, because you don't go out and replace sort of in kind with old technology. So, in the end, it will be a bit more modern facility when it's finished.

GREG PARDY:

Got it. Okay, thanks so much.

OPERATOR:

Our next question is from Phil Gresh with J.P. Morgan.

PHIL GRESH:

Yes, hi, good morning. I just wanted to ask about the outlook for 2019 production. I know it's early to give a specific outlook, but I was just referring back to your slides that you gave with the MEG presentation, where you had guided to greater than 410,000, and I think MEG would be about a 100,000 run rate in '19, so that would imply maybe like 310,000 for you guys. I know there's a reduction in the guidance for this year. So, I guess, was that all kind of contemplated already in what you put out there?

ROBERT PEABODY:

No, I mean, I think what you're picking up is something else, which is we don't know when the closing date for MEG is going to be, so we just kind of made—you know, we made some assumptions about it closing some time maybe towards—some time in the first quarter of next year, but at the current schedule, it wouldn't be closing January 1. So, we aimed off of it on production because we know it might be not a—the annual number may be affected by that.

PHIL GRESH:

Okay, okay. I guess, is there any colour maybe on moving pieces you could talk about? I know you've talked about some of it on thermal and whatnot, but anything you can share?

ROBERT PEABODY:

I don't think—I mean, I think we will come out—I mean, one of the things we'll see—I mean, normally, we would come out with full production guidance in December. We're just re-evaluating that. Clearly, if we think this transaction is going to close, then we will—we might push that back a little bit, so we can get a really good handle on exactly two things, what exactly MEG will be able to produce and also when the deal closes, and then we can put out some fairly detailed guidance.

PHIL GRESH:

Okay, and then just the second question is on the Upstream operating costs. I know you guided to about \$13 to \$13.50 for the year. The summer has some seasonality to it, but you were

above \$14 a barrels, I think, each of the past two quarters. So, I just wanted to get your sense on these trends on these Upstream operating costs and how you feel about those heading into the end of the year.

ROB SYMONDS:

Yes, I think—Phil, this is Rob Symonds. Clearly, the disappointing results on the Atlantic infill well are driving unit costs up. A lot of fixed costs, of course, in those Offshore facilities. So, as I look at that going forward on operating costs, I think we're certainly going to be at the top end of that range that we talked about on a full-year basis.

PHIL GRESH:

Okay, thanks.

OPERATOR:

Our next question is from Neil Mehta with Goldman Sachs.

EMILY CHIENG:

Hi, this is Emily on behalf of Neil.

ROBERT PEABODY:

Hi, Emily.

EMILY CHIENG:

Hey. I had a couple of quick questions, one on the CapEx outlook. I know you guys raised CapEx by about \$200 million this year. I just wanted to see what that implied for the next five years. I think you guys put out CapEx guidance of \$3.5 billion, on average. Does this imply any sort of upward pressure?

ROBERT PEABODY:

No, not really, I wouldn't draw that conclusion. Again, when we get our guidance and we put this all together, we'll come out with new capital guidance, but I don't read through that situation as changing the overall outlook for capital over the next five years.

EMILY CHIENG:

Got it, that makes sense. Then, the second one is just on the asphalt plant that you guys are looking at, previously sanctioned. I guess the question is where do you expect asphalt margins to sort of shake out in the next couple years, particularly in sort of 2020 and beyond? I guess, how do you weigh up covering heavy Canadian oil exposure versus potentially weaker asphalt pricing in an IMO 2020 world?

JEFF RINKER:

Yes, I think—this is Jeff Rinker. I think, directionally, IMO 2020 is bearish for asphalt, just how much, though, is really difficult to tell. Asphalt tends to move a lot more with materials pricing and GDP growth and infrastructure spending, and all that kind of stuff, which we think that, actually, North America, in general, has a bit of a deficit built up in infrastructure that has to be closed at some point of time, and so that makes me, actually, longer term, a bit more optimistic about the asphalt prices holding up.

The good news here is, of course, we don't need to take a decision on building the new asphalt plant right away, we've got some time before that becomes a decision that's right in front of us. Rob mentioned six to nine months, as we see how the pipelines, the outlook develops. But, yes, we think it's a good option for us, but we don't have to pull the trigger on the option for a little bit of time yet.

ROBERT PEABODY:

I'd only add one thing to that, which is important. As we kind of migrate the asphalt business forward, we are already a fairly—you know, there's kind of the wholesale produce-it-at-a-refinery sort of part of the business, then it's the sort of supplying-it-to-end-users sort of part of the business, and one of the things we—we do a lot of supplying to end users in the asphalt business and that's kind of a growing part of our business strategy. The margin, when you look at the margin we pull out of our asphalt business, a significant enhancement to that margin is around sort of what I would call the end user market side of the business. So, when we say we're one of the top asphalt producers in North America, that's a key part of our business, is sort of taking it further down the value chain there.

EMILY CHIENG:

Make sense. Thank you very much.

OPERATOR:

Our next question is from Harry Mateer with Barclays.

HARRY MATEER:

Hi, good morning. You guys have been pretty clear about commitment to investment grade ratings since the MEG offer came out. I'm just wondering if you can put a slightly finer point on it. Do you view mid-Bbb ratings as sort of a floor below which you're not willing to go, or should we just think of the commitment as generally just investment grade, but you don't want to put a specific notch on it?

JEFF HART:

It's Jeff here. I'll break it out in context of the statements from both Moody's and S&P, and obviously there's a process to go through with them, but, fundamentally, I think both came out, as expected, from a credit negative perspective just in a statement, but I think if you look at Moody's and you go through the statement just fundamentally, subject to doing the work with them, I think we can do that and expect to affirm our current rating of Baa2, and in S&P's case, the view is—from their view at this point, there's a lot of ambiguity that they'll just sit on right now, is it'll be a one-notch max down to Bbb. I think there's a path forward—our desire is to maintain Bbb+ and Baa2, and I think we have a path forward for both, and I think coming out and looking at the statements of both Moody's and S&P, I think we're in a good place to do that.

HARRY MATEER:

Got it. So, mid-Bbb ratings are important to you?

JEFF HART:

Yes, absolutely.

HARRY MATEER:

Okay. Great, thank you.

OPERATOR:

This concludes time allocated for the question and answer session. I would like to turn the conference back over to Mr. Rob Peabody for any closing remarks.

ROBERT PEABODY:

Thanks. Thanks, everyone, for joining us this morning. I think the summary is we continue to deliver on our five-year plan and have already achieved our free cash flow target for the year that we set out at Investor Day. With the physical integration of our Upstream and Downstream businesses, we are unaffected by location and quality differentials, as demonstrated by the last quarter, and we expect that to continue as we go through the year, and that's all backstopped by our committed export pipeline capacity, as well as our upgrading and refining infrastructure. With most of our production tied to global pricing, we have stability in our funds from operations and are improving our ability to generate free cash flow. I guess, finally, our proposal to acquire MEG allows us to accelerate delivery of our 2022 targets. It'll generate more free cash flow that can be directed towards cash returns to all shareholders and invested in our expanded growth portfolio. Our website has more information about the offer and why it makes sense for the shareholders of both companies.

So, thanks again for your questions and joining us this morning.

OPERATOR:

This concludes today's conference call, you may disconnect your lines. Thank you for participating and have a pleasant day.

LEGAL ADVISORIES

NO OFFER OR SOLICITATION

This document is for informational purposes only and does not constitute an offer to buy or sell, or a solicitation of an offer to sell or buy, any securities. The offer to acquire MEG securities and to issue securities of Husky Energy Inc. (the “Company”) is made solely by, and subject to the terms and conditions set out in, the formal offer to purchase and takeover bid circular and accompanying letter of transmittal and notice of guaranteed delivery.

NOTICE TO U.S. HOLDERS OF MEG SHARES

The Company has filed a registration statement covering the offer and sale of the Company’s shares in the acquisition with the United States Securities and Exchange Commission (the “SEC”) under the U.S. Securities Act of 1933, as amended. Such registration statement covering such offer and sale includes various documents related to such offer and sale. **THE COMPANY URGES INVESTORS AND SHAREHOLDERS OF MEG TO READ SUCH REGISTRATION STATEMENT AND ANY AND ALL OTHER RELEVANT DOCUMENTS FILED OR TO BE FILED WITH THE SEC IN CONNECTION WITH SUCH OFFER AND SALE OF THE COMPANY’S SHARES AS THOSE DOCUMENTS BECOME AVAILABLE, AS WELL AS ANY AMENDMENTS OR SUPPLEMENTS TO THOSE DOCUMENTS, BECAUSE THEY CONTAIN OR WILL CONTAIN IMPORTANT INFORMATION.** You are able to obtain a free copy of such registration statement, as well as other relevant filings regarding the Company or such transaction involving the issuance of the Company’s shares, at the SEC’s website (www.sec.gov) under the issuer profile for the Company, or on request without charge from the Senior Vice President, General Counsel & Secretary of the Company, at 707 8th Avenue S.W. Calgary, Alberta or by telephone at 403-298-6111.

The Company is a foreign private issuer and is permitted to prepare the offer to purchase and takeover bid circular and related documents in accordance with Canadian disclosure requirements, which are different from those of the United States. The Company prepares its financial statements in accordance with Canadian generally accepted accounting principles, and they may be subject to Canadian auditing and auditor independence standards. They may not be comparable to financial statements of United States companies.

Shareholders of MEG should be aware that owning the Company’s shares may subject them to tax consequences both in the United States and in Canada. The offer to purchase and takeover bid circular (or any applicable supplement) may not describe these tax consequences fully. MEG shareholders should read any tax discussion in the offer to purchase and takeover bid circular (or any applicable supplement), and holders of MEG shares are urged to consult their tax advisors.

A MEG shareholder’s ability to enforce civil liabilities under the United States federal securities laws may be affected adversely because the Company is incorporated in Alberta, Canada, some or all of the Company’s officers and directors and some or all of the experts named in the offering documents reside outside of the United States, and all or a substantial portion of the Company’s assets and of the assets of such persons are located outside the United States. MEG shareholders in the United States may not be able to sue the Company or the Company’s officers or directors in a non-U.S. court for violation of United States federal securities laws. It may be difficult to compel such parties to subject themselves to the jurisdiction of a court in the United States or to enforce a judgment obtained from a court of the United States.

NEITHER THE SECURITIES EXCHANGE COMMISSION NOR ANY STATE SECURITIES REGULATOR HAS OR WILL HAVE APPROVED OR DISAPPROVED THE COMPANY’S SHARES OFFERED IN THE OFFERING DOCUMENTS, OR HAS OR WILL HAVE DETERMINED IF ANY OFFERING DOCUMENTS ARE TRUTHFUL OR COMPLETE. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

MEG shareholders should be aware that, during the period of the offer, the Company or its affiliates, directly or indirectly, may bid for or make purchases of the securities to be distributed or to be exchanged, or certain related securities, as permitted by applicable laws or regulations of Canada or its provinces or territories.

FORWARD-LOOKING STATEMENTS

Certain statements in this document are forward-looking statements and information (collectively, “forward-looking statements”) within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as “will likely result”, “are expected to”, “will continue”, “is anticipated”, “is targeting”, “is estimated”, “intend”, “plan”, “projection”, “could”, “should”, “aim”, “vision”, “goals”, “objective”, “target”, “scheduled” and “outlook”). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: general strategic plans and growth strategies; production expectations; and the anticipated benefits that may result from a combination of the Company and MEG;
- with respect to the Company’s thermal developments in the Integrated Corridor: expected timing of ramp-up to design capacity at Rush Lake 2; expected timing of first production at Dee Valley, Spruce Lake North and Spruce Lake Central; expected timing for two additional 10,000 bbls/day projects to be brought online; expected overall production from new thermal developments; and timing for infill wells at Sunrise to come on production;
- with respect to the Company’s resource plays in the Integrated Corridor, drilling plans; and
- with respect to the Company’s Downstream operations in the Integrated Corridor: the expected timing of completion of the crude oil flexibility project at the Lima Refinery, and the increase in heavy oil capacity expected to result therefrom; and the expected timing of resumption of normal operations at the Superior Refinery and timing for receipt of insurance proceeds.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company’s forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate, including the ability to obtain regulatory approvals and meet other closing conditions to any possible transaction, and the ability to integrate the Company’s and MEG’s businesses and operations and realize financial, operational and other synergies from the proposed transaction. Those assumptions and factors are based on information currently available to the Company about itself, MEG and the businesses in which they operate. Information used in developing forward-looking statements has been acquired from various sources, including third-party consultants, suppliers and regulators, among others.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company’s Annual Information Form for the year ended December 31, 2017, offer documents and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon

management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

NON-GAAP MEASURES

This document contains references to the terms “funds from operations”, “free cash flow”, “net debt”, “net debt to funds from operations”, “net debt to trailing funds from operations”, “EBITDA” and “operating netback”, which do not have standardized meanings prescribed by International Financial Reporting Standards (“IFRS”) and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measures is used to enhance the Company's reported financial performance or position. These measures are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. There is no comparable measure in accordance with IFRS for operating netback.

Funds from operations is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, cash flow – operating activities as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Funds from operations equals cash flow – operating activities plus change in non-cash working capital.

Funds from operations was restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

Free cash flow is a non-GAAP measure, which should not be considered an alternative to, or more meaningful than, cash flow – operating activities as determined in accordance with IFRS, as an indicator of financial performance. Free cash flow is presented to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures and investment in joint ventures.

Free cash flow was restated in the first quarter of 2018 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the addition of investment in joint ventures. Prior periods have been restated to conform to current presentation.

The following table shows the reconciliation of net earnings to funds from operations and free cash flow, and related per share amounts, for the periods indicated:

(\$ millions)	Three months ended			Nine months ended	
	Sep. 30 2018	Jun. 30 2018	Sep. 30 2017	Sep. 30 2018	Sep. 30 2017
Net earnings	545	448	136	1,241	114
Items not affecting cash:					
Accretion	23	25	27	72	84
Depletion, depreciation, amortization and impairment	672	639	673	1,929	2,235
Exploration and evaluation expenses	-	7	1	7	6
Deferred income taxes	156	138	52	371	1
Foreign exchange gain	(6)	(2)	(3)	(7)	(5)
Stock-based compensation	40	33	11	94	20
Gain on sale of assets	-	-	(2)	(4)	(33)
Unrealized mark to market loss (gain)	(22)	(26)	31	(134)	(1)
Share of equity investment income	(18)	(26)	(12)	(53)	(60)
Other	(2)	19	9	19	8
Settlement of asset retirement obligations	(45)	(22)	(23)	(116)	(91)
Deferred revenue	(25)	(25)	(9)	(70)	(11)
Distribution from joint ventures	-	-	-	72	25
Change in non-cash working capital	(35)	(199)	3	(600)	61
Cash flow - operating activities	1,283	1,009	894	2,821	2,353
Change in non-cash working capital	35	199	(3)	600	(61)
Funds from operations	1,318	1,208	891	3,421	2,292
Capital expenditures	(968)	(708)	(511)	(2,313)	(1,475)
Investment in joint ventures	-	-	(12)	(40)	(72)
Free cash flow	350	500	368	1,068	745

Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Net debt is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

The following table shows the reconciliation of total debt to net debt as at the dates indicated:

(\$ millions)	Sep. 30 2018	Jun. 30 2018	Sep. 30 2017
Short-term debt	200	200	200
Long-term debt due within one year	388	394	-
Long-term debt	4,964	5,015	5,236
Total debt	5,552	5,609	5,436
Cash and cash equivalents	(2,916)	(2,583)	(2,486)

Net debt	2,636	3,026	2,950
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Net debt to funds from operations is a non-GAAP measure that equals net debt divided by FFO. Net debt to funds from operations is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

Net debt to trailing funds from operations is a non-GAAP measure that equals net debt divided by the 12-month trailing FFO as at September 30, 2018. Net debt to trailing funds from operations is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

EBITDA is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with IFRS, as an indicator of financial performance. EBITDA is presented in this document to assist management and investors in analyzing operating performance by business in the stated period. EBITDA equals net earnings plus finance expenses (income), provisions for (recovery of) income taxes, and depletion, depreciation and amortization.

Operating netback is a common non-GAAP measure used in the oil and gas industry. This measure assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

All currency is expressed in this document in Canadian dollars unless otherwise indicated.