HUSKY ENERGY

FOURTH QUARTER 2017 CONFERENCE CALL AND WEBCAST TRANSCRIPT

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Speakers:

Robert Peabody
President and Chief Executive Officer

Jonathan McKenzie
Chief Financial Officer

Rob Symonds
Chief Operating Officer

Dan Cuthbertson
Director, External Communications and Investor Relations

OPERATOR:

Welcome to the Husky Energy Fourth Quarter 2017 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.

At this time, I would like to turn the conference over to Dan Cuthbertson, Director, External Communications and Investor Relations. Please go ahead, Mr. Cuthbertson.

DAN CUTHBERTSON:

Thanks, and good morning. I'm here with CEO Rob Peabody, CFO Jon McKenzie, COO Rob Symonds, and other members of our Senior Executive team. They'll provide an overview of our fourth quarter and annual results and then take your questions.

Today's call will include forward-looking information. The associated risk factors are described in this morning's news release which you can find on our website and in our annual filings on SEDAR and EDGAR.

All figures mentioned today are in Canadian dollars and before royalties, unless otherwise stated.

Please contact our Investor Relations team directly if you have specific modeling questions. Rob will now kick off the call.

ROBERT PEABODY:

Thanks, Dan. Good morning, everyone. I'm pleased to say that Husky's Board of Directors has approved a quarterly cash dividend of $0.075 per common share in conjunction with our fourth quarter results. It will be paid on April 2, 2018. The dividend is amply covered by our free cash flow generation and underpinned by our low debt levels. The Board has taken this action in light of the continuing strength of our balance sheet, our steadily increasing free cash flow and earnings which have been driven by our repositioned asset base, and the current price environment.

Our deep portfolio of higher return investment opportunities continues to further reduce our cost structure and sustaining capital requirements, contributing to increasing our funds from operations as well as our free cash flow. This has been the result of a very deliberate focus on driving down the oil price we need to break even as a company. The oil price required to fund our sustaining capital requirements and pay the current level of dividend is about US$35 WTI.

We have now seen eight quarters of steadily improving funds from operations. In 2017, we realized $1.1 billion in free cash flow, excluding the acquisition of the Superior Refinery. Using a US$55 WTI oil price assumption, we expect to match or beat that this year.

In regards to the strength of our balance sheet, our net debt is now less than 1 times trailing funds from operations, well below the target in our five-year plan.

Turning now to our 2017 highlights, we delivered on the targets we set for the first year of our five-year plan, and in some areas exceeded them. We generated $3.3 billion in funds from operations, up 50% from $2.2 billion in 2016. We surpassed our anticipated free cash flow target by more than $250 million. Our capital spending came in at $350 million lower than originally planned while accelerating the timetable for several projects including the Rush Lake 2 thermal project and a couple of wells in the Atlantic region.

Our average proved reserves replacement ratio was 167% excluding economic factors. This exceeded the target of our five-year plan, which is to average more than 130% per year. The physical integration and transportation capacity of our business are key factors in contributing to our results. They largely eliminate our exposure to widening Canadian heavy oil differentials.

Our Integrated Corridor business includes 110,000 barrels a day of Canadian refining and upgrading capacity. In addition, we have significant transportation capacity, giving us the ability to get our products to our U.S. refining asset. These include our fixed long-term commitment of 75,000 barrels per day on the existing Keystone Line, as well as access to the Enbridge Line out of Canada. In addition, we have committed capacity on Flanagan South and the Southern Access Line. This gives us routes to the U.S. markets where there are significantly lower discounts to heavy oil.

On top of the pipeline access, we have about 5 million barrels of crude storage capacity along the Integrated Corridor, providing further flexibility to manage the volatility in prices and differentials.

In terms of production, we averaged 323,000 barrels of oil equivalent per day in 2017, which was within our guidance despite asset sales in Western Canada which were not included in our original forecast.

The Western Canada sales program is now complete, and we are set for strong Upstream organic production growth, averaging about 7% per year through to 2021.

This divestment program that we did in Western Canada was just one of the steps taken over the past few years to structurally transform and improve the cash and free cash flow generating ability of our asset base. Since the program began in late 2015, we've sold about 52,000 barrels of oil equivalent per day, and this production had operating costs of around $17 per barrel of oil equivalent to produce and as well further investments in these assets didn't meet our hurdle rates as a corporation. We've replaced these legacy barrels with lower cost production. Average operating cost for our new Lloyd Thermal projects are around $8 per barrel, and Thermal production is no contributing about 121,000 barrels per day to our total production. That represents about 40% of Husky's entire Upstream production base and the average operating cost for all that production is around $10 per barrel.

Drilling down a bit further into our results, year-over-year Thermal production increased by 22% with a significant contribution from the steady ramp up at Sunrise and our strongest production to date at Tucker. Two more Lloyd Thermal projects were sanctioned, meaning we'll be bringing on an additional 60,000 barrels a day of new Lloyd heavy oil production beginning in 2019 through to 2021.

Turning to the Downstream business, we achieved record throughputs in 2017. Utilization rates for our U.S. refineries notched up to a new high at around 99% in the third quarter. We purchased the Superior Refinery and with that purchase we increased the size of our U.S. Refining business to nearly 300,000 barrels a day, and all of that is benefitting from the recent changes in U.S. tax legislation.

In the Offshore, we saw strong gas demand in China with the Liwan Gas Project achieving our best ever quarterly production rate. Liwan generated EBITDA of approximately $770 million in 2017.

The 29-1 field has now been sanctioned. The first of three planned wells is scheduled to start in the fourth quarter of this year, and these three wells, just to remind you, add to the four wells that were previously drilled on this project. First gas is planned for 2021.

Offshore Indonesia, the liquids-rich BD Project in the Madura Strait continues to ramp up towards its full gas sales target.

Looking now at the Atlantic Region and West White Rose, construction activities are underway for the wellhead platform. First oil is set for 2022 with net peak production of 52,500 barrels per day Husky interest when this reaches its full production levels. This project benefits from our ability to tieback to existing infrastructure, resulting in incremental operating costs of only $3 a barrel over the first decade.

All in all, we finished 2017 on a stronger and leaner note. We recorded improved funds from operations and free cash flow. We lowered our average per barrel operating cost and further reduced the oil price needed to breakeven on earnings and cash flow.

Now I'll hand it over to Jon who will take us through our full year and fourth quarter financial results.

JONATHAN MCKENZIE:
Great. Thanks, Rob. Starting with the fourth quarter, net earnings were $672 million and this includes a deferred tax recovery of CA$436 million due to changes in the U.S. corporate tax rate. Adjusted net earnings were $665 million and this figure includes adjustments for impairments, write-offs and gains.

I'll just take a moment to explain the anticipated impact of the recent U.S. tax changes on Husky. At the highest level, we're not expecting to be cash taxable in our U.S. business until 2020. We anticipate total cash tax reduction of CA$75 million per annum starting in 2020.

Meanwhile, funds from operations for the quarter were a little over $1 billion which included a pre-tax FIFO gain of $71 million. This was a year-over-year increase of 57% and in line with the planned trajectory we outlined at Investor Day.

Capital spending was $745 million and we generated free cash flow of $294 million excluding the Superior acquisition.

Average production was 320,000 boe per day and this compares to 327,000 boe per day in the fourth quarter of 2016, reflecting the wrap-up of the asset disposition program.

Just a side note that our production in Q1 2018 will reflect the closing of the last of these asset sales in the fourth quarter which amount to about 17,600 boe per day of oil and gas production. It also takes into account the end of the Wencheng PSC in November. Husky's share of the light oil production from this asset in Q4 averaged 2,600 barrels per day.

We saw good performance from our Asia Pacific operations with the highest ever gas sales production at Liwan and the addition of the liquids-rich BD Project in Indonesia. Liwan gas sales averaged CA$13.40 per Mcf with liquids pricing of $67.92 per barrel. With OpEx of only $4.72 per boe, we achieved a netback of $68.47 per boe.

Overall, the realized price from our Upstream production was $46.69 per boe, up from $39.90 in the year ago period. Operating costs in the Upstream continue to trend down. They were $13.20 per barrel, down from $13.92 last year at this time. Upstream operating netbacks were $30 per boe compared to $22.32 in the fourth quarter of last year.

In the Downstream segment, upgrading and refining throughputs averaged 387,000 barrels per day which includes contributions from the Superior Refinery following its acquisition in early November. This compares to 350,000 barrels per day in Q4 of 2016. Superior has raised our total upgrading and refining capacity to about 400,000 barrels per day which includes 190,000 barrels per day of heavy oil processing capacity. It's also contributing significantly to higher free cash flow over the five-year plan that we set out at our Investor Day.

Our funds from operations reflect the value generated by these integrated Downstream assets. Our Lloyd Value Chain, for example, captured netbacks of $43.92 per barrel in the fourth quarter compared to $28.83 from this Upstream production alone.

The Sunrise Value Chain generated $37.39 per barrel in total netbacks versus $16.50 from this field alone.

The Chicago 3:2:1 crack spread averaged US$20.28 per barrel. This compares to US$10.59 per barrel in the fourth quarter of 2016. Average U.S. realized refining margins were US$14.71 per barrel, which included a pre-tax FIFO adjustment gain of US$2.40 per barrel. This compares to US$9.86 per barrel a year ago, which included a pre-tax FIFO adjustment gain of US$1.43 per barrel.

At the Lloyd Upgrader, synthetic crude prices remained strong at $73.91 per barrel, and we saw margins of $20.65.

Downstream EBITDA was $471 million in the quarter, which is up 107% from the fourth quarter in 2016.

As Rob mentioned, our long-term transportation capacity and integrated business structure largely eliminates our exposure to Canadian heavy oil differentials. As a result, even with the widening light-heavy spreads in December, our funds from operations were similar to that in October and November as our Downstream assets benefit from the lower feedstock costs. We are well positioned to process our products in Canada or move our heavy barrels to where the light-heavy oil differential is not as large.

Now turning to our annual highlights, in our guidance for 2017 we targeted overall Upstream operating costs to settle into the $14 to $15 range per barrel. These have actually come in a bit lower, averaging $13.93 per barrel, and we’re looking to reduce that number even further to the range of $13 to $13.50 this year.

Upstream operating netbacks were $25.25 per boe compared to $16.19 per boe in 2016.

Funds from operations were up 50% year-over-year to $3.3 billion compared to about $2.2 billion in 2016.

Free cash flow was $1.1 billion which is more than double the $493 million in the previous year.

Net earnings were $786 million and adjusted net earnings were $882 million for the year.

Net debt at the end of the year $2.9 billion. This included the Superior Refinery acquisition and is below 1 times net debt 2017 funds from operations. Significantly contributing to our overall lower debt is the reduction of our working capital requirements through 2017.

All of these figures are available on our website so you can measure our progress against the targets that we laid out at our Investor Day in May.

Meanwhile, our financial flexibility remains strong. There are no major long-term maturities until June 2019. At year end we had $2.5 billion in cash and more than $4 billion of unused credit facilities, and we are maintaining our strong investment grade credit ratings today.

Looking ahead to 2018, as mentioned in our guidance call in December, we're targeting production to average in the range of 320,000 to 335,000 boe per day, and that our planning price assumptions of US$55 WTI and $2.50 AECO, and a Chicago 3:2:1 crack spread of about $15 per barrel, we expect to generate funds from operations in excess of CA$4 billion, and free cash flow of over $1 billion.

Now I'll turn the call over to Rob Symonds to talk about our Q4 operational progress.

ROB SYMONDS:
Thanks, Jon. I'll begin with the Integrated Corridor business. Our thermal bitumen production averaged 121,000 barrels a day including Lloyd, Tucker and Sunrise, with combined operating costs of $9.83 per barrel. At Lloyd, construction is continuing on the central processing facility at Rush Lake 2 and we have completed drilling a dozen well-pairs. The next Lloyd Thermal in the queue is Dee Valley where we expect to begin construction in the second quarter. This will be followed by Spruce Lake North and Spruce Lake Central. All three projects are scheduled for

first oil in 2020. In December, we announced the sanctioning of the next two Thermal projects, Edam Central and Westhazel. We're planning to bring both online in the second half of 2021.

Collectively, with these six projects, we will be adding 60,000 barrels a day of Lloyd Thermal production in the 2019 to 2021 timeframe.

At Tucker, steaming on the new 15-well pad began in the fourth quarter and first oil is expected in the next few days. Average production was 22,600 barrels per day in the quarter and we remain on pace to meet our production target of 30,000 barrels a day by the end of this year.

At Sunrise, the original 55 well pairs are producing within our target range of 800 to 900 barrels a day and are now running with an SOR of 3.1 to 3.2. All of the additional 14 well pairs are now on production and ramping up as scheduled. Average year-to-date gross production is 46,700 barrels a day compared with 46,000 barrels a day in Q4 of 2017.

We recompleted a few of the original Sunrise wells in January and February. As such, we're not anticipating production at the project to change materially during the first quarter. We do expect to return to our upward trajectory in the second quarter and remain on track to reach 60,000 barrels a day at the end of the year.

Turning to our resource plays, we've wrapped up our 16-well drilling program in the Wilrich, at Ansell and Kakwa, and we're moving ahead with a 17-well program this year. Three Husky Wilrich wells that were brought on production in the fourth quarter ranked within the top 10 performers in Alberta in December. They're continuing to outperform our expected type curve. One well peaked at over 19 million standard cubic feet per day in November. Current sales gas production from all four wells is exceeding our plans, currently about 25 million standard cubic feet per day.

In the Montney Formation, we drilled three liquid-rich gas wells in the fourth quarter at Wembley and started up two oil wells at Karr.

In the Downstream business, our throughputs included 78,200 barrels a day at the Lloyd Upgrader which had a capacity utilization of 97%. Synthetic crude oil sales averaged 56,500 barrels a day during the fourth quarter with 6,100 barrels a day of diesel.

Throughputs at the asphalt refinery averaged 30,000 barrels a day, 100% utilization.

In the U.S., quarterly throughputs averaged 267,500 barrels a day including 22,000 barrels a day from Superior averaged in the quarter. Superior ran at about 37,000 barrels a day following our acquisition in November. Total gasoline and diesel sales increased some 244,000 barrels a day in Q3 to 252,000 barrels a day in Q4. December came in at 278,000 barrels a day with the full month's contribution from Superior.

We have a fairly light turnaround year in 2018 and you can see the details in this morning's press release.

In our Offshore business, starting first in the Asia Pacific region, Liwan gas sales averaged a record 361 million standard cubic feet per day in the fourth quarter, with a 177 million standard cubic feet per day net to Husky. Associated liquids from Liwan was 7,300 barrels a day Husky's share, bringing Husky’s total production to some 36,600 barrels of oil equivalent per day.

In Indonesia, the liquid-rich BD project is ramping up, albeit at a bit slower pace than we would have liked. This is due to lower demand from industrial end users. Sales gas volumes in Q4 was 17 million standard cubic feet per day net to Husky. Customer demand is building in the region and we’ve connected a second delivery pipeline. We expect to hit our production targets by the end of this year.

In the Madura Strait, we're advancing the next phase of shallow water developments at the MDA-MBH and MDK field. We plan to start drilling seven wells at MDA-MBH in the first half of this year with first gas anticipated in 2019.

In the Atlantic Region, production operations on the SeaRose FPSO were suspended for 10 days in early January at the direction of the offshore regulator. We took a number of actions, including organizational changes and improvements to our local emergency response procedures and ice management plans. The SeaRose is now back to full rate.

At the main White Rose field, the development well drilled in the third quarter of last year was brought on production in Q4. Drilling was also completed at a second well at North Amethyst and that well is expected to be brought onstream by the end of March. We have another well planned at the main White Rose field is scheduled to come online in the third quarter of 2018. Each of these wells is expected to add 3,500 barrels a day at peak production Husky working interest. We plan to bring on an average of two wells per year to help offset natural decline rates in the Atlantic Region until we begin operations at West White Rose.

Meanwhile, we are planning to pour the first concrete for the wellhead platform at West White Rose during the second quarter. We're targeting first oil in 2022 and expect to ramp up to gross peak production of 75,000 barrels a day in 2025, which will be 52,500 barrels a day net to Husky.

Thank you, and now I'll turn the call back to the Operator so that we can 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, then one on their touch-tone telephone. You will hear a tone to indicate you're 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, then two. One moment, please, while we poll for questions.

The first question comes from Benny Wong of Morgan Stanley. Please go ahead.

BENNY WONG:

Yes, thanks. Good morning, guys. Just wondering how you guys are determining the $0.075 quarterly dividend is appropriate. If my math is right, it looks like it's about 15% your earnings payout and I think that might have been alluded to being the case before. How should we think about the growth potential of that going forward? Would to pace it with your production growth or does the earning and cash flow metric make more sense.

ROBERT PEABODY:

Yes. Thanks, Benny. I mean I think we establish the dividend pretty much in line with the comments I made earlier last year which were, really, we're looking to re-establish a competitive but modest dividend as a starting point with the idea as we continue clearly to drive down our earnings breakeven, continue to improve the structure of the Company, we would look to be able to grow that over time. That really is kind of at the broadest level is how we thought about just the level we initially established it at.

BENNY WONG:

Great, thanks for that. Just wondering if we can get an update of Superior Refinery you guys recently acquired. Have you guys learned anything new since taking it over, and if you can remind us, how much heavy can you run through that facility, and if there's ability to increase that over time.

JONATHAN MCKENZIE:

Yes. Hi, Benny. It's Jon McKenzie. The refinery since we acquired it on November 9 has run well and we've been very pleased with the acquisition. As we alluded to I think on previous calls, this refinery currently runs in a blocked operation where we run 100% heavy or we run a lighter crude slate, and we're switching back and forth.

When you think about this refinery, we can run somewhere between 20,000 to 25,000 barrels a day of blended heavy through that refinery on a sustained basis, and then coming out of the turnaround in May we're looking to push that number up with a couple of projects that we would like to execute in that timeframe. There's been no surprises to date in terms of how this refinery has run and that speaks to the due diligence that we did through the process prior to acquiring this refinery, but it's been and I think it will continue to be a very good asset for us and we're very pleased with the acquisition to this point.

BENNY WONG:

Sounds great, and just a final one, if I may. I think it was recently announced that one of your partners that the Terra Nova project is maybe looking to sell its stake. I'm wondering if you guys would look at that, maybe at the right price, and does that project have any growth potential that might fit within your five-year plan? Thanks.

ROBERT PEABODY:

Thanks, Benny. I think I have to give the answer that we generally don't comment on M&A anyways. I mean we look at every opportunity that comes on to the market, clearly, but that's all I can say on that, I think, right now.

BENNY WONG:

Understood. Thanks, guys.

ROBERT PEABODY:

Thanks.

OPERATOR:

The next question comes from Neil Mehta of Goldman Sachs. Please go ahead.

EMILY CHANG:

Hi, guys. This is Emily Chang calling on behalf of Neil Mehta. Congrats on a great quarter. I think what we're sort of focused on is really the WTI/WCS pricing environment and we're well aware that Husky's are finding capacity drilling matches, you know, the Company's heavy oil production. As you think about your thermal projects coming online in the coming 12 months to 24 months, how do you think about expanding the refining business in order to remain protected against aligning spreads?

ROBERT PEABODY:

Thanks, Emily. Yes, I guess a couple of things just to add a little context to. Of course one of the interesting dynamics going on in the pricing market right now is that we talk about the heavy light differential, but it's kind of a Canadian heavy and then U.S. light differential because the heavy differential in the United States is actually not particularly wide. In fact, it's quite tight at the moment, partially because it's hard to get any of that heavy down from Canada.

As you point out what we like about our asset base right now is that we have the ability to move the crude from Canada into the United States and kind of get through that bottleneck that's really causing the problem in terms of price differentials. Certainly, as we pointed out, with our asset base plus the Keystone pipeline capacity we're able to do that, and of course Superior enhanced our ability to do that quite a bit as well because with all that extra refining capacity rate on the Mainline, the Enbridge Mainline into the U.S., it allows us to nominate through their nominating procedures at higher levels. All that is very good.

In terms of the longer term outlook for us, I mean at the moment we're in a good position. Going forward through to 2020, 2021 we kind of maintain that position and of course we have a number of projects underway to increase our heavy processing capacity in our system, including the COF project in Lima which will allow us to run more heavy crude in Lima.

So, we feel pretty good through to 2020, 2021. Clearly we are watching the situation on the pipelines carefully to see how this moves forward, feeling reasonably optimistic certainly on a number of those options. As it becomes clearer of what pipeline capacity's actually going to be in service, say in 2022, which I think will become clear fairly soon—in the next 12 months probably—it will be much clearer as to whether we need to look at further expansion opportunities, which also include the Lloydminster Asphalt Plant that we have the option to still move forward with, or whether or not we feel more comfortable that we'll have better conductivity to other markets and that the heavy light discounts will improve in a more structural way for the longer term. We'll weigh that as we kind of get clarity over the next 12 months how that goes, but in the meantime, until the time until about 2020, 2021, we are pretty well covered by our own asset base.

EMILY CHANG:
Fantastic, that's very helpful. Thank you.

ROBERT PEABODY:
Thanks, Emily.

OPERATOR:
The next question comes from Paul Cheng from Barclays. Please go ahead.

PAUL CHENG:
Hey, guys, good morning.

ROBERT PEABODY:
Good morning, Paul.

PAUL CHENG:
Number of maybe a modelling question for Jon first. Jon, on the year-end DD&A, is there any particular reason why they dropped so much sequentially from the third quarter?

JONATHAN MCKENZIE:

Yes. In the fourth quarter, Paul, we true-up our reserves and reserve additions in Q4 offset the DD&A cost in the quarter.

PAUL CHENG:

Is there any particular asset that you have true-up?

JONATHAN MCKENZIE:

The true-up was largely in the Heavy Oil area, so in the Lloydminster region.

PAUL CHENG:

I see, okay. That means that this will be a good baseline as we're heading into 2018.

JONATHAN MCKENZIE:

That's correct.

PAUL CHENG:

On the Upgrader, the transfer price for the heavy oil that you use as a feed, are those based on the spot price or based on the three-month price?

JONATHAN MCKENZIE:

Those are based on the fully blended market price for heavy oil at Lloydminster.

PAUL CHENG:

Is it the spot price or the three-month?

JONATHAN MCKENZIE:

It would be a combination of spot and monthly.

PAUL CHENG:

I see. I was a little bit surprised that in the infrastructure joint venture you actually record a loss. What triggered that loss?

JONATHAN MCKENZIE:

Yes, so what happened in the joint venture, it's a true-up that we do one in the fourth quarter for the Husky volumes that have gone through the pipeline. Because the Husky volumes were so strong through the first three quarters, they are entitled to some rebates in the fourth quarter; those all get recorded in the fourth quarter. It's a reflection of the performance through the first three quarters that gets trued-up in the fourth quarter.

PAUL CHENG:

I see so you said it is basically—okay. That means that we should assume that when we're looking that we should look at the full-year and sort of annualize it?

JONATHAN MCKENZIE:

That's right.

PAUL CHENG:

Say as a reasonable quarter.

JONATHAN MCKENZIE:

That's right, Paul.

PAUL CHENG:

Do you have a Superior profit contribution since November 7 that you can share?

JONATHAN MCKENZIE:

In the first two months of operations the earning contribution is pretty flat, Paul. The reason is we have to work off the inventory that we purchased from Calumet. That inventory has largely been run through right now, so there's a small contribution on the cash flow side. The earnings contribution is zero, but on a go-forward basis what you should be using on the cash flow side is about $100 million.

PAUL CHENG:

Okay.

JONATHAN MCKENZIE:

Obviously that's an annual number and that's a U.S. dollar figure.

PAUL CHENG:

Okay. When we're looking from the fourth quarter as a baseline into 2018, is your capitalized interest going to have meaningful changes? Also, do you have an estimate that what are cash tax that we should assume in 2018, and also for the next couple of years for that matter?

JONATHAN MCKENZIE:

I wouldn't expect a meaningful change in the capitalized interest outside of as we start to ramp up the spend on West White Rose. That will attract more capitalized interest. Then when you think about the cash taxes that we pay as a company in 2018, we're cash tax—we're taxable in three jurisdictions. We don't anticipate being cash taxable in Canada. As I mentioned in my presentation, we don't anticipate being cash taxable in the in the U.S. in 2018. We are cash taxable in China, and you should be using a figure of about 25% for that jurisdiction.

OPERATOR:

The next question comes from Joe Gemino of Morningstar. Please go ahead.

JOE GEMINO:

Thank you. How do you think about potential LNG projects off the west coast of Canada having any potential impact on your Indonesia or China natural gas operations?

ROBERT PEABODY:

Hi. This is Rob. I think the short answer to that is zero. The LNG market is a big global market. In the end, China is going to be—well, number one, just to be clear, the contracts we have in both of those jurisdictions are kind of effectively life-of-field contracts now with fixed gas prices.

JOE GEMINO:

Oh, great. One unrelated question to that. If there are further delays in some of the crude pipeline expansion projects, do you see yourself in a position potentially where you would delay any of your thermal growth projects?

ROBERT PEABODY:

No, not really. Again, as I say, we're pretty well covered for all the thermal projects we've already moved forward with at the moment, and i.e. the six that are in various stages of development and construction at the moment, so we're in pretty good shape there. Again, I think we're in a strategically advantaged position, I would say, relatively speaking, given that we have this large refining business in the United States and we have the production in Canada and we also have a big interest in the midstream. Yes, there's always things to manage but I think we're in a better position to manage it than many of our peers.

JOE GEMINO:

Great, I appreciate that. Thank you.

OPERATOR:

The next question comes from Mike Dunn of GMP FirstEnergy. Please go ahead, sir.

MICHAEL DUNN:

Thanks. Good morning, everyone.

ROBERT PEABODY:

Good morning.

MICHAEL DUNN:

Just a question on the Madura gas volumes. I think you mentioned that demand there's been slower than expected to pick up. Is that a logistical issue onshore or is it—and if not, I guess how should we be thinking about the variability that that might cause us through 2018 and 2019 you ramp up additional projects there? Thanks.

ROB SYMONDS:

Okay. Good, thanks. This is Rob Symonds. I think do we'd start out, Mike, just putting it in context, it's not unusual that the markets are a little slow on the uptake when we're bringing on new supply. I mean we certainly saw that at Liwan and Liwan we were protected by take-or-pay, and we are in Indonesia also protected a bit on take-or-pay. Q4, it’s about 40 million a day with the 6,200 barrels of liquid, which with our 40% share is 17 million and 2,400. I'd tell you today rates are more in the 50-plus range, so we are seeing that ramp up.

The second pipeline that I mentioned has allowed us to get to a second market, so that there was, if you like, a bit of an infrastructure constraint, but what we're seeing is the end users were a little behind what we anticipated, but they continue to take more. We expect that by the end of the year will be at full rates.

ROBERT PEABODY:

Yes, I'd add one other piece of context. Similar to China, Indonesia actually really needs more gas. This is more of a step change when you bring something on, getting it in place, getting new demand, but if you stand back from both Indonesia and China, they're both looking to rapidly increase the amount of gas utilization in a very big way, and they do see domestic gas production is still at the front of the queue in terms of what they want to use.

MICHAEL DUNN:

Thanks, Rob. Thanks, everyone.

ROBERT PEABODY:

Thanks.

ROB SYMONDS:

Thanks, Mike.

OPERATOR:

The next question comes from Dennis Fong of Canaccord Genuity. Please go ahead.

DENNIS FONG:

Hi, good morning. Earlier in your comment, you alluded to over $1.1 billion of free cash flow this year, or at least in terms of your current view for your operations. With respect to a $300 million plus or minus cash dividend, how should we think about the capital allocation of the remaining, call it, $800 million of excess free cash flow given that you already have a fairly strong balance sheet and there are some, but not a lot of kind of short cycle growth projects that you guys can target? Thanks.

ROBERT PEABODY:

Yes, okay. I mean, again, I'll maybe put it in a wider context and just say that, again, part of the value proposition is returning cash to shareholders and that's what the dividend is for, and hence we've moved forward with the decision to do that. Looking forward and we look at that different—we're going to consider all options to return cash to shareholders as we go forward. I mean in addition we'll look at—clearly, we'll always look at opportunities out there that are closely married to our strategy. There are a number of companies out there that are—there's probably more higher quality assets potentially available than there have been before that are very close to our strategy. That being said, they'd have to meet hurdle rates and everything else and we're not going to go crazy. We're looking at relatively modest things here. But as we look at excess cash building up, because we're through the normal dividend, we're not paying out all our free cash flow. We would look at number one as we alluded to earlier increasing the dividend over time, and certainly where we've established it we've wanted to leave headroom there to do that. Then, also, if you go back to the history of Husky, we have on occasions where there was kind of too much cash building up and that was getting to very low levels, the Board has taken a decision to pay special dividends; that's just the history. The other mechanism that's available there are share buybacks. We've been always a little careful with those because we're conscious that our float as a relative size isn't as big as some of our—some of the other peers, but that's certainly another tool in the toolbox.

DENNIS FONG:

Perfect, thank you.

OPERATOR:

The next question comes from Phil Gresh who's with JPMorgan. Please go ahead.

PHIL GRESH:

Hi, good morning. I guess if I were to follow-up on that last comment, is there is a level of debt that you—or cash that you are looking to have? Minimum cash or debt that you'd be looking to have, after which you'd think it'd be too low?

JONATHAN MCKENZIE:

Yes. Phil, it's Jon. Just in terms of, I'll answer the cash question first and then I'll pivot towards the debt.

There isn't a cash level that we target. With the cash balances that we have today, we're comfortable that we have no financing risk in 2019, 2020, so we've got a lot of options there with the $2.5 billion that we've got on the balance sheet today. Going forward, we don't necessarily target a cash balance; it's really a mismatch between the cash that we've accumulated and the maturity of our debt.

In terms of what we've talked about publicly in terms of a debt level, what we've said is we don't want to be in the position of having more than two times debt to cash flow at a $35 price, so the target that we've put out for the debt is something under $4 billion now. Today we're much less than the $4 billion. We are about $2.9 billion and that's after we acquired Superior. We really didn't anticipate being at this low level of debt at year end having made that acquisition. With a lot of the work that was done on the working capital on top of the operations, we find ourselves in a real privileged position, I guess, in terms of the net debt on the balance sheet.
What we think the assets can absorb with the capital commitments that we've made is something in that $4 billion range.

PHIL GRESH:
Okay, that's helpful. Thanks. Second question would just be on the capital spending front. Jon, I think I guess I've asked you this before, but how do you feel about the sustaining capital needs of the business today? As you look at that budget for this year and even beyond this year that you provided at the last Analyst Day, how would you frame that today based on the accomplishments you saw in 2017?

JONATHAN MCKENZIE:
Yes, so we're right on track with where we thought we would be at this time in terms of sustaining capital, and what we've put out publicly is a sustaining capital number of about $1.9 billion, and that breaks down to about $1.4 billion for the Upstream and about $500 million for the Downstream. As production continues to grow through this timeframe, we would expect that to come up marginally, and it may come up into the sort of the $2.1 billion range, sort of the end of the plan, but that's very comfortably covered by the cash flow that we generate at the bottom of the cycle. Today, as I mentioned, we would generate about $2.1 billion of cash flow at $35 which we consider to be the bottom of the cycle.

Once we've made all these investments in the business, that number grows to about $3.1 billion at $35 WTI, so the improvement in the business then throws up more free cash flow which can either be used to invest in the business, return to shareholders, increase the dividend, and the like. But the key that we're doing is really transforming the business to maintain a low level of requirement for sustaining capital and continuing to invest in assets that generate free cash flow at the bottom of the cycle.

PHIL GRESH:
Okay, thank you. For the free cash flow this year, the FFO of about $4 billion, I'm curious do you have a split as to how much you think is from Upstream versus Downstream?

JONATHAN MCKENZIE:
That’s a moving target.

ROBERT PEABODY:
Yes, it was quite interesting. I guess—this is Rob—the one thing I would add there it is a very moving target, it’s quite interesting. We always say that the integration of our Integrated Corridor there provides us a lot of protection, and it’s quite interesting when we run our own models where when the differential blows out and all these things happen. It can move a huge amount of the total cash flow and earnings from the Upstream to the Downstream along that Integrated Corridor, but the total number doesn't actually change that much. I mean, I guess the one interesting thing when we were running some of these things around Christmas was just that after the U.S. tax changes, we actually got a slight benefit from the big differentials because more income was showing up in the U.S. where the tax rate was a little bit lower than in Canada now. It’s kind of interesting, but we’re relatively, I guess, not worried about where that happens.

Then the other thing, of course, which is worth mentioning is our Asian business is now really generating a lot of cash flow, a lot of free cash flow and of course that's with fixed price contracts and everything is again giving us a lot of stability in this period of a lot of volatility in some of the other areas.

PHIL GRESH:
Sure, yeah. You tend not to get a lot of credit for your Downstream business, so I was trying to just tease that out a little bit.

ROBERT PEABODY:

I appreciate it.

PHIL GRESH:

On the differentials.

ROBERT PEABODY:

My head of Downstream is sitting at the table here and he's always telling me that too, and it's absolutely true. I don't think people appreciate that our Downstream is just as big as our Upstream now.

PHIL GRESH:

Last question would just be on the IMO 2020 standards. What's your view on it? Do you believe that this will be a—will there be a material change in differentials or diesel cracks that will come from this? Is there anything that you'd be looking to do to capitalize on that if you did believe that?

ROB SYMONDS:

Yes, this is Rob Symonds. IMO 2020, it's been around a while, of course, and we've been looking at it for a long, long time. We have, I think you've seen us positioning our assets with that in mind, particularly around the asphalt, the asphalt space. If you look at Lima, specifically, Lima we're already biased to diesel. It's more like a 2:1:1 than a 3:2:1, and certainly we expect that what the IMO rule is going to do is make coking capacity more valuable. We see that there will be incremental ULSD demand, and we can debate exactly how much people go to that versus putting in scrubbers and the like, but that will translate into higher cracks and increase the value of our diesel and jet. Overall, given the products that we make and the location of our refineries, we think we're probably likely net beneficiaries of the rule.

PHIL GRESH:

Okay. Thanks a lot.

OPERATOR:

This concludes the analyst Q&A portion of today's call. We will now take questions from members of the media. As a reminder, please press star, then one on your touch-tone phone to ask a question. If you wish to remove yourself from the question queue, please press star, then two. We will pause for a moment as callers join the queue.

The first question comes from Chris Varcoe, who is with The Calgary Herald. Please go ahead.

CHRIS VARCOE:

Hi, Rob. I've got a couple of questions, one is in light of the U.S. tax reform, I'm just wondering how you view the competitiveness of Canada and making investments in the Canadian oil patch versus the United States or other international opportunities.

ROBERT PEABODY:

Thanks, Chris. Yes, I mean it's hard to not be concerned about Canada's competitiveness right now, and it is something we're concerned with. I mean Husky has a real advantage in that we have choices we can make, and we continue to make them. Having the large U.S. refining business has proved to be very beneficial that way. But I'm concerned. I mean as many of my colleagues have also said, in many ways a tax is a tax is a tax and we're seeing lots of additional sort of taxes coming on in Canada, while at the same time the biggest competitor to the South, the big gorilla, is dropping taxes. It makes it hard to take investment decisions to put dollars into Canada because ultimately we are, like all companies, we have to go where the returns are at any given place.

I think the other area which is just as important as the tax side of it is the regulatory side of it, and again, it's not about specifically what the regulations say in many cases, it's just the amount of flux in the regulatory environment where there's just thing after thing after thing that is sort of like under consideration, potentially going to get changed, and that, and there's nothing that stops investment as firmly as just not knowing ultimately some of these key—how you're going to be regulated at the highest level. I mean, I have to sell these things to a Board and when they ask these questions like what is the tax level going to be and how does regulation affect this investment? When you say, "Well, we should know in a few year's time," they generally boot you out of the room.

I am concerned. I'm hopeful, but I'm concerned. Hopefully we'll wake up to the situation and we'll start taking some actions to remedy it.

CHRIS VARCOE:

My follow-up is just, what are your expectations for the heavy-light differential for this year, and I guess how does that shape your thoughts on the need for new pipelines coming out of Western Canada more generally?

ROBERT PEABODY:

Well, as I say first, I would say that in terms of Husky we're well positioned through to 2021. The second thing I would say is absolutely Canada needs to have more than one customer. That would be a smart thing for its oil, its oil that’s produced. As I tell people around here I have lots of friends that are Americans, but we do not have to be as generous as a country to the U.S. as we're currently being, and certainly if you’re Alberta we’re being extremely generous, and I don't think that makes a lot of sense. I'm certainly a strong proponent of getting the pipelines that are currently under consideration built because I think people sometimes don't relate to what we're really talking about here is also that the royalties and taxes that go into our hospitals, go into our schools, that allow us to take care of the elderly, all these things are put in jeopardy as a province and as a country when we're willing to discount our products in such a massive way to the customers. Canadians are generous, but this is getting a little carried away.

OPERATOR:

There are no more questions at this time. This concludes the question-and-answer session. I would now like to turn the conference back over to Mr. Rob Peabody for any closing remarks.

ROBERT PEABODY:

Well, thanks, everybody, for your questions. Just to sum up I’d say we continue to meet or surpass the target set out at the five-year plan that we shared with you at our last Investor Day. The structural transformation of our company is providing for increasing funds from operations and free cash flow, lower operating costs and better earnings and cash breakeven. Our physical integration and secure transportation access is contributing significant value to us and has largely eliminated our exposure to the Canadian differentials. Finally, our strong balance sheet and improved earnings and cash flow capability have led us to establish a cash dividend.

We'll be updating our five-year plan at our 2018 Investor Day at the end of May, so I hope a lot of you will be able to join us there, and thanks again for joining us today.

OPERATOR:

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