



HUSKY ENERGY

FOURTH QUARTER 2019

CONFERENCE CALL TRANSCRIPT

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

Rob Symonds
Chief Operating Officer

Jeff Hart
Chief Financial Officer

Jeff Rinker
Senior Vice President, Downstream

Dan Cuthbertson
Director, Communications and Investor Relations

Janet Annesley
Senior Vice President, Corporate Affairs and Human Resources

Operator:

Welcome to the Husky Energy Fourth Quarter and annual 2019 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, Director of Investor Relations. Please go ahead, Mr. Cuthbertson.

Dan Cuthbertson:

Hello and thanks for joining us on the call this morning. CEO Rob Peabody, COO Robert Symonds, CFO Jeff Hart, and other members of our management team are here to discuss our fourth quarter and annual results and then we will take your questions.

Today's call has forward-looking information and non-GAAP measures. The identification of forward-looking information and non-GAAP measures, the risk factors and assumptions pertaining to the forward-looking information and additional information pertaining to the non-GAAP measures are in this morning's news release and in our annual filings on SEDAR and EDGAR. All numbers are in Canadian currency and before royalties unless stated otherwise. A reminder to please save your specific modeling questions for our Investor Relations team to answer following the call.

Thanks very much and now Rob Peabody will begin the review.

Robert Peabody:

Thanks, Dan, and good morning.

As you saw from our news release this morning, this was a tough quarter. Funds from operations were \$469 million. At a normal run rate and with our Investor Day pricing assumptions, we could've delivered almost twice that amount.

While our upstream operations ran to plan, the biggest gap was in our U.S. downstream results. The shutdown at the Lima Refinery to complete the crude oil flexibility project lasted almost the entire quarter with an impact of about \$180 million on our funds from operations. Of that \$180 million, about \$90 million of this was expected due to the planned shutdown while \$90 million was due to the extension of the shutdown.

U.S. crash spreads were also very weak, resulting in an impact of about \$120 million.

The Keystone Pipeline outage in November and narrower location differentials, negatively affected our infrastructure and marketing segment by about \$50 million. We also incurred \$74 million in severance costs related to staff reductions that took place in October.

Looking at our annual results, we wrote off \$2.3 billion in after-tax impairments and other charges in the fourth quarter. Jeff will address this in a little more detail in his section.

On the operations front, we made good progress in 2019 on safety. This included reductions in our total recordable and lost time injuries and Tier 1 process safety incidents. This will drive more consistent operational performance as we accelerate our transformation to a High Reliability Organization. We have set a target to become top quartile in process and occupational safety by the end of 2022 as measured against global benchmarks. The progress we made on these metrics in 2019 gives us confidence that we are well on our way to achieving that goal.

As a safety-focused employer and as a business with operations in China, I'd like to talk about how we're responding to the virus outbreak. After the extended break for the Chinese New Year, our workers have returned to their offices. Our Asia Pacific facilities have continued to operate under strict health protocols throughout this period. We are continuing to monitor developments in all regions in which Husky operates to ensure the well-being of our staff and their families.

In terms of how this is impacting our Asia-Pacific volumes, typically our buyers take reduced volumes from the Liwan Gas Project at this time of year due to lower demand related to the Chinese New Year. This shortfall is usually offset later in the year when they take more than

their contracted rate. However, given the extended holiday, because of the precautions surrounding the virus, demand for Liwan gas was lower for longer than usual. In the past few days, however, we have seen an uptick in demand to full rates.

Overall, we made good progress in 2019 on the critical business milestones that we set out for the year. This was despite headwinds created by the government-mandated curtailments in Alberta and a slower than anticipated return to full volumes in the Atlantic region. Production of 290,000 barrels of oil equivalent per day was at the bottom end of our guidance. The annual capital expenditures were also at the low end of our guidance, and we maintained the strength of our balance sheet and stayed within our debt targets.

Annual funds from operations were \$3.3 billion compared to \$4 billion in 2018. This reduction is due to the following factors: the extended maintenance outages at the partner-operated Toledo Refinery, the extended shutdown at Lima that I spoke about earlier, the slow start-up of the SeaRose in the Atlantic region, which is now at full rates, the Alberta quotas, and of course, lower commodity prices when compared to 2018.

Touching on a few project highlights from 2019, starting with the Integrated Corridor . . . Our latest Lloyd thermal project at Dee Valley came online ahead of schedule in the third quarter, and we continue to advance three near-term thermal developments. Spruce Lake Central, and Spruce Lake North will start up later this year. Spruce Lake East will follow in 2021. All three projects are making good progress and are on schedule and on budget.

In the downstream at Lima, all the units are now running and we expect to ramp up to full crude rates by March. Heavy crude processing capacity has increased to 40,000 barrels a day, up from 10,000 barrels a day, providing the crude supply optionality that will lead to improved margins over time. We also closed the sale of the Prince George Refinery in the fourth quarter, which has further focused our Integrated Corridor business.

In the offshore business, starting with the Atlantic, production at the three White Rose drill centers was restarted in the first half of the year and the remaining two drill centers were brought online in August. The White Rose project is now 57% complete and we're continuing to see good project execution and productivity with first oil by the end of 2022.

In Asia, construction of the 29-1 field at Liwan continues to progress and we're on pace for first gas in the fourth quarter of this year. As these projects come on stream, they'll further grow our funds from operations. At the same time, their completion allows us to reduce our capital spending.

When we released our capital guidance a couple of months ago, we said we would reduce spending by \$100 million in 2020 and a further \$400 million in 2021 compared to our previous plan that we had set out in Investor Day earlier that year. We remain committed to maintaining this capital discipline with a priority on returning value to our shareholders through a strong dividend, while investing for margin growth. We're also advancing our work on carbon targets, and we'll update you on these later this year.

Now, I'll turn the call over to Jeff to review our Q4 financial results.

Jeff Hart:

Thanks, Rob.

I'll start with the asset impairments and other charges that we booked in Q4. The impairments were largely driven by lower commodity price assumptions and a reduction in future capital investments in the Canadian upstream business. They primarily impacted the book value of our upstream assets, including Sunrise, the White Rose field, and gas resource plays in Western Canada.

The other charges included asset derecognition at the Lima refinery associated with redundant equipment following the completion of the crude oil flexibility project. Excluding the impairments and other charges, we had net earnings of \$5 million in the quarter. In regards to net debt, we exited the year at \$3.7 billion and total liquidity is now \$5.7 billion in cash and unused credit facilities.

In terms of reserves, total proved reserves before royalties at the end of 2019 were 1.4 billion boe, about the same as the previous year. With the deferral of capital programs at Sunrise and Ansell, we had a probable reserves reduction of 395 million boe. The average three-year proved

reserves replacement ratio was 166%, excluding economic factors, and the proved reserves life index remains at 13.5 years.

Turning now to the fourth quarter. Funds from operations were \$469 million compared to \$583 million in the year-ago period. This was mostly due to the lower U.S. crack spreads and the extended Lima shutdown. Our operating costs at the refinery are largely fixed and there was little revenue contribution in the quarter. As a result, the U.S. refining segment had a negative operating margin of about \$170 million Canadian. And for context, the U.S. refining segment posted an average operating margin of \$190 million Canadian per quarter in the first three quarters of 2019. This means the delta in the quarter was about \$360 million. As mentioned earlier, we booked \$74 million in severance costs.

Turning to upstream operations, overall production was 311,000 boe per day in Q4 compared to just over 304,000 boe per day in Q4 of last year. These barrels received an average realized price of about \$46 per boe, compared to about \$25.50 in the prior-year quarter. The upstream operating netback averaged \$27.48 per boe compared to \$9.42 a year ago, reflecting higher realized pricing for heavy oil. Upstream per-unit operating costs were \$15.25 per boe compared to \$13.75 per boe at this time last year, due in part to higher energy costs and lower production.

The offshore business delivered an operating netback of \$61 per BOE.

The operating margin in the infrastructure and marketing segment was \$12 million compared to \$175 million in Q4 of 2018, and this was largely because of the tighter location differentials and the Keystone Pipeline outage in Q4 2019.

The U.S. refining and marketing margin was \$7.85 US per barrel of crude throughput, which included a negative pre-tax FIFO impact of 0.24 US per barrel. We also realized \$116 million in pre-tax insurance proceeds related to business interruption at the Superior Refinery.

Capital spending in Q4 was \$894 million compared to \$1.3 billion at this time last year. This includes rebuild costs at Superior of \$48 million, which are expected to be largely recovered from insurance. Looking forward, this year is expected to mark a step-change in our five-year capital program.

By the end of this year, we will have started up the 29-1 field and the Spruce Lake North and Spruce Lake Central thermal projects. In addition, the bulk of our spending at West White Rose will be behind us as the project advances towards first production around the end of 2022.

However, we expect a few headwinds in Q1. This includes the potential for a slower recovery in gas demand in China related to the virus. In Lima, we had an average throughput of 105,000 barrels per day in January. We're now at about 140,000 barrels per day as we continue to run off intermediates. We expect throughput to increase, but we'll still run off intermediates through March. Also, production at the partner-operated Terra Nova FPSO remains suspended.

Just a reminder that beginning next quarter, we will be adjusting the way we report our financial results to reflect the Integrated Corridor and Offshore segments. This will better align our reporting to the two businesses and provide for greater transparency and ease of modeling.

Finally, our priority remains maintaining capital discipline and returning value to our shareholders through sustainable dividend increases. We are maintaining the strength of our balance sheet. On top of that, we are continuing our strategic review of the commercial fuels and retail business. We are also continuing to pursue other opportunities to further reduce capital and expenses. This will see us through to next year when we expect to reach a positive free cash flow inflection point.

For this quarter, the Board is maintaining the current level of dividend at \$0.125 per common share.

Thanks. Now, I'll pass the call over to Rob Symonds.

Robert Symonds:

Thanks, Jeff.

Overall, thermal production from Sunrise, Tucker, and Lloyd averaged about 138,000 barrels a day net to Husky in Q4. This compares to 133,000 barrels a day in the same period last year. We have set a target to reach 90,000 barrels a day of Lloyd thermal production by the end of 2019 and we met this with the December average of 92,000 barrels per day.

In the area of thermal operating costs and emissions intensity, we've been active on several fronts. An artificial intelligence pilot program to enhance steam utilization at the Sandall project has been successful.

We've seen reductions in steam requirements of approximately 10%. Concurrently, production has improved around 2%, meaning greater operating profitability with less environmental intensity. This program is now being extended to Edam with plans to roll it out to all of our producing projects in Saskatchewan later this year. We also have pilots underway at Sunrise and Pikes Peak South that use non-condensable gases to lower steam to oil ratios. As we expand these programs, they will provide for increased production through the redeployment of the steam that is being freed up, further reducing the environmental footprint of our operations.

Another big milestone in 2019 was the startup of the Aberfeldy facility. This is our first full-field polymer injection project in Saskatchewan and will increase oil recovery from this heavy oil field. It's also the first of several potential longer-term, lower-cost EOR oil applications across our heavy oil business as we move forward from our legacy CHOPS production.

In the downstream, overall upgrading and refining throughputs in Q4 averaged just over 203,000 barrels a day compared to 287,000 barrels a day in Q4 of 2018. This included 79,600 barrels a day at the Lloyd Upgrader and 28,200 barrels a day at the Asphalt Refinery.

In the U.S., we saw combined volumes at Lima and Toledo of 91,700 barrels a day. This takes into account the full shutdown at Lima as well as extended maintenance at the partner-operated Toledo Refinery. With Lima now online, overall downstream processing capacity is 355,000 barrels per day, including 195,000 barrels a day of heavy oil upgrading and conversion capacity. Overall capacity will grow to 400,000 barrels a day when Superior comes back online around the end of 2021, with total heavy processing capacity of 220,000 barrels per day.

In Western Canada, during the fourth quarter, we started up six liquid-rich wells in the Montney formation at Wembley. In the offshore business, construction of the 29-1 field at Liwan is about 80% complete and remains on track to start up in Q4. All seven wells have been drilled and completed and the sub-sea flow lines have been installed.

Work is now underway offshore again, and next up is the installation of the control system connecting and de-watering the various flow lines. Once fully ramped up, this field will add about 9,000 boe a day to our Asia production.

Offshore Indonesia at the BD project, the FPSO was taken offline for two weeks in January for maintenance, but it's now back producing at full rates. In the Atlantic, overall net production was about 24,000 barrels a day in the quarter, inclusive of the impact of the partner-operated Terra Nova shutdown that occurred in late December. The West White Rose project is now 57% complete and remains on schedule.

At Argentina, the final quadrant of the concrete gravity base was completed ahead of schedule in the fourth quarter. We're preparing now for the main shaft slipform, which will start in the second quarter of this year. At Ingleside, Texas stacking of the individual decks is now underway. This was a major milestone that will allow the topsides construction to continue its upward progress. Combined, average net production for Asia in the Atlantic in Q4 was 70,000 boe a day. Husky working interest is up from about 64,000 boe a day a year ago.

As for our planned 2020 turnarounds . . . Along the Corridor, we will be completing a project in the second quarter at the Lloyd Upgrader to increase our diesel capacity to almost 10,000 barrels a day. This will take about six weeks. The partner-operated Terra Nova FPSO, in which we have a 13% working interest, is currently scheduled to be offline for up to seven months. We also have regular maintenance scheduled at Liwan and Sunrise in the second quarter and on the SeaRose in the third quarter. The details of all of these are available on our website.

Thanks.

Now, I'll turn the call back to the Operator for 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 touch-tone phone. You will hear a tone to indicate you're in the 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 while we poll for questions.

Our first question comes from Greg Pardy of RBC Capital Markets.

Greg Pardy:

Thanks. Good morning. Three quick ones for you. I guess the first is just on the severance charges. How much will that reduce your run rate G&A in 2020?

Jeff Hart:

Yes. Thanks Greg, it's Jeff here. We kind of think it will be split, but about \$50-60 million will be in SGA then we'll have savings in the other cost categories in the P&L, and that will total about \$75 million we'd expect in ongoing savings on a run-rate basis.

Robert Peabody:

That's kind of a piggyback on the charge.

Greg Pardy:

Okay. Okay yes. So, it's an annual number. Okay, great. When you take down the Upgrader, I guess Rob was mentioning it, whatever it is, six weeks or so, that'll just be a partial shutdown or is it more dramatic than that?

Robert Peabody:

I'll let Jeff Rinker answer that.

Jeff Rinker:

Hi, Greg. This is Jeff. We're taking the whole Upgrader down. We take the full Upgrader down once every four years, and we take one of the hydrocrackers down every second year, so this will be a full shutdown.

Greg Pardy:

Okay. Great. The last question is just on the reduced capital spend and so forth then just the impact on reserves on both the 1P and the 2P basis. Could you dig into that a little bit about where those changes were made and then what the implications are, if any?

Jeff Hart:

I'll break it out into two categories. We'll talk to the proved reserves and then just the probable impacts. If you look at proved . . . the reductions are really in the gas business and it's really reducing capital on Ansell and Kakwa. That's really driven by price and us cutting back the capital frame, maximizing free cash flow. On the probable side it is, again, if you look at the gas beside, it's the same thing Ansell and Kakwa, and then you'll see a similar impact or an impact in our bitumen product line and that's really cutting back future phases on Sunrise and focusing on free cash flow as well. So, it's really in those two areas and it's really capital reductions.

Robert Peabody:

Yes. The only thing I'd add to that, Greg, is again, as we know, those barrels have not really gone anywhere. It's just that under the reserve recognition rules, if you're not spending capital in the next five years, you have to derecognize them. So, that's the driver, of course, and then once you derecognize them, that flows back into your impairment calculations and how you value those reserves.

Greg Pardy:

Okay. Terrific. Thanks very much.

Operator:

Our next question comes from Benny Wong of Morgan Stanley.

Benny Wong:

Good morning. Thanks for taking my question. Rob, I want to thank you for the update and your prepared remarks around China on the coronavirus. There seems to be quite a bit of concern around your natural gas pricing contracts in the region, just given where regional gas and LNG prices have been moving. Can you maybe provide some perspective around that and if the perceived risk is warranted? I'm curious if you've had some dialogue with CNOOC around a situation.

Robert Peabody:

So Benny, I think clearly looking at the whole situation in Asia at the moment, although it does seem to be kind of spreading across the world, there are issues with total gas demand.

Although, as I said earlier in the call, we're actually almost pleasantly surprised at the moment that they have now ramped up to full rates, even a little higher than the normal full rate. So, we are seeing a bounce back in those volumes at the moment.

Again, the history here is we have a very strong relationship with CNOOC. The last time we got involved with CNOOC on discussions around this contract when there were major differences, I think both sides walked away feeling they got what they needed, which was we needed to preserve value and we were able to do that in those negotiations. We did, at the time, agree a small decrease in the gas price over time, but in return, they also offered us some things like extensions around Wenchang and things like that. So, value was preserved under the nature of the contracts. At the moment, we're just continuing to deliver the gas and we haven't really heard much from them.

Benny Wong:

Great, appreciate those thoughts. The second one is more around your retail sale process. South of the border there's a big refinery that's selling their retail business as well, and there's been recent headlines of interest of an overseas buyer. Just curious and just in general how your process is going and if you're seeing the same interest as well, understanding that the business asset might be a little bit different?

Robert Peabody:

Yes. I guess what I'd say there is—we've run an extensive process. We certainly did see interest from a wide range of buyers including overseas buyers. Until things are signed, we believe we're in the relatively late stages of that process and we'll update you when we have something specific to say.

Benny Wong:

Great, thanks. Just my final question and it's related to Jeff's prepared remarks. I think you mentioned you guys are looking at opportunities to further reduce capital. Just wondering if

you're able to provide some early sense of what you're looking at and sense of magnitude that we should be thinking about?

Robert Peabody:

Well, let me put that—I'll let Jeff if he wants to add in a second, but let me just give you the overall context. First, just clearly, when we put out our guidance at the end of last year, we did actually reduce our capex guidance relative to what we had said we were going to do at the Investor Day earlier in that year. We took our \$100 million out of 2020 and \$400 million out for next year, and again indicating that we would expect that the run rate capital level will drop on a more sustaining basis beyond 2021. So, we've already baked that into the plan.

We are of course, and I'm sure most of our colleague firms out there will be looking at capital programs again given what we're seeing with oil prices and margins, given the virus outbreak and all these things going on. So, what I'd assure you is we've done enough to understand we do have more capital flexibility. There is more room that we can reduce capex this year. We haven't finalized those plans, but our finger's over the trigger, I guess you could say, if they're required.

Then in terms of at the back of all this, I think there's always going to be a little bit of concern when things turn very south in the industry around the dividend. But, we're still feeling very good about our ability to sustain the dividend. Hence the Board's decision to continue to pay the dividend in current levels. That's on the back of a balance sheet that is still very strong in terms of the industry overall, the potential retail sale I spoke about earlier, and of course, this idea that we do have some potential additional capital flexibility if we need to go that way in the year.

Benny Wong:

Understood, thanks, Rob.

Operator:

Our next question comes from Prashant Rao of Citigroup.

Prashant Rao:

Hi, good morning. Thanks for taking the question. Rob, I wanted touch back on something you said there about the dividend program. Appreciating that there's been a leverage you can pull

for further capex reduction and the balance sheet being still fairly solid, how do you think about debt leverage levels from here, especially given that, I'm trying to ramp this in with the impairments which obviously reflect a lowered, a more conservative commodity price outlook. Is there room to take a little bit more incremental leverage? What's your comfort level as you move towards your targeted free cash flow, positive inflection points next year? Where could we see that go and how should we think about that with respect to the sanctity of the dividend?

Robert Peabody:

That's great. I'm going to let Jeff answer that.

Jeff Hart:

So, we finished the quarter here at around \$3.7 billion and the way to think about our target is, as we always say, two times net debt to FFO at the bottom of the cycle. That triangulates now with what we can generate at \$40 WTI is about \$4.5 billion in net debt. So, that's where we're comfortable, we'll manage around that because we don't want to do anything imprudent to the business and obviously, we've got the retail process going as well. So, we feel we've got the options there and we've got a few hundred million to half a billion or a little bit more room in the balance sheet. So, that's the way we're thinking about it and we'll manage in and around that.

Robert Peabody:

I think the only thing I'd add to Jeff's remarks is of course, and as we outlined at Investor Day next year, as you go through this year, we finished the COF project, which was a substantial spender of capex. We're going to finish two more thermals as we go through the year, one about the middle of the year and one towards the back end of the year. So, those will be out, 29-1 in China will be finished. So, all those turned from net capital consumers now to actually revenue generators.

If you look at the West White Rose project, next year and the year after are much less heavy spending years, because I kind of think of them as assembly years. We've largely built all the major components and then in 2021 they're all assembled, then in '22, they're deployed to the fields. So, those are much less spending years. So, we still see this inflection point in capital spending, where that is going to drop very significantly as we go from this year to next year.

As I say, I think we have some additional capital flexibility we can pull this year if we need to. But in any case, we're going to see a big inflection down in capital as we go into next year.

Between all those projects, we've got about another 30,000 barrels a day of production coming on-stream, effectively by the end of the year. We also have the COF project in Lima up and running. So, it gives us more flexibility, better opportunity to drive higher margins.

I guess the one other project that we didn't mention explicitly, but as part of the Upgrader turnaround, of course, we're going to finish the work on the diesel enhancement project that takes our diesel rates up at the Upgrader from about 6,000 to just under 10,000 barrels a day, and actually incrementally adds a little bit of capacity to the Upgrader's throughput as well. So, all those things are moving in the right direction.

So, I just want to give you a sense, as the Board's thinking about the dividend now, they're also saying, 'Look, we've got all these levers as we manage this year, and actually as we go to next year, we actually see a very big inflection point driven by lower capital spending plus all this additional production and margin enhancement projects coming on-stream.'

Jeff Hart:

Yes. To Rob's point, as you're looking 9 to 10 months and you've got two thermals on, and 29-1, so you're really stepping down that capital range. So, the risk profile is a little bit different.

Prashant Rao:

Okay. I appreciate the detail and answer from all of you. Next question I have is related—I touched upon on the commodity price outlook change. As it relates to the impairments, Rob, you talked already about some of the derecognition process in terms of reserves, and how that works. But, there are other two big levers here. One is commodity price when we think about an impairment, right? The other is really discount rate that's applied. So, to the extent that you could talk about or give some colour, how much of the impairments are purely a function of commodity price environment view and how much could be potentially the auditors even looking at discount rate assumptions on some of these projects you got ahead, particularly on the gas side?

Jeff Hart:

Yes. It's Jeff here, I'll talk to that. Broadly speaking, the vast majority of the impairments are really driven by commodity price. That's really the drive and that's the way people should be thinking about it, is the revision down in the long-term price lines. So, the discount rates, there's a bunch of accounting things that go on with that to make sure that it's a reasonable rate and reflects the cash flows of the individual assets. But, broadly speaking, is the way you should be thinking about is the vast majority is price.

Prashant Rao:

Okay, great. Just one last one for me. On the crude oil flexibility impairment, it looks like there were some redundant equipment that was—that's really impairment once you've come out of that now. Was part of that known that you might have some redundancies there or did you discover that as you went through the process?

Jeff Hart:

Yes, I'll talk that. As you go through and obviously this quarter, we did a lot, we're doing work on this past quarter, the distillation, the coker. What I'd say is individual small sub-components of the major units. As you're going through and pulling that out, is that point should derecognize and there's nothing to read into that other than just you can't have two sets of pipe on the book and the like. They're all sub-components of the major units.

Prashant Rao:

Okay. That's great. Thanks for your time. Appreciate it. I'll turn it over.

Operator:

Our next question comes from Phil Gresh of J.P. Morgan.

Phil Gresh:

Yes. Hi. Good morning. First question just on Superior in light of some of the recent news flow around the tower there. It sounds like you're still confident in the end of 2021 timing, but maybe you could just frame what happened there and how you feel. How confident you are in that timing still, and just where you are in the process. A little bit more on that. Thank you.

Robert Peabody:

I'll get Jeff Rinker to answer that. He's been close to that in the last few days.

Jeff Rinker:

Thanks. Yes. Hi, Phil. Thanks for the question. Yes. Just to look what happened. Last Thursday, the construction workers that were working on the project heard this loud noise that came from the FCC stack at the site. These are construction workers that are experienced, not really normally affected by noises. It was a serious noise and we took it seriously. We evacuated the area around the stack until we had a chance to inspect it and find out if there was anything wrong with the stack.

Subsequently, we've done visual inspection. We've done measuring the movement of the stack. We don't see anything at all wrong with the stack, but we are going to complete a thorough mechanical inspection of the stack to make sure that there is absolutely sure there's nothing wrong with it. So, that's going on.

We did pull the workers away from the site around the stack. We'll lose about a week of time in the field. This is not going to affect the overall project schedule though, because the critical path right now isn't in the field. The critical path is with fabrication of long-lead equipment and detailed engineering, which is happening in shops and offices around the country. We'll be back to work at the site soon, as soon as we have the stack secured with the crane and we don't expect to lose any time on the project. We're still on track for late 2021 start-up of the refinery.

Phil Gresh:

Okay. All right, thanks. My second question, I guess for Rob. I'm looking at the Analyst Day slides here from last year and just some of the 2020 specific data points and the guidance that you've provided back in December. If I look at the production and the cash flow, more the CFO, obviously you've changed your capex, but thinking about more of the production CFO in light of the 2019 performance in the fourth quarter shortfall. Is there anything from your perspective that you would be carrying through to 2020 or reading through to 2020 as a result of 2019, or this is mostly one-time transitory factors? Just any thought you can provide. Thanks.

Robert Peabody:

Yes. Thanks for the question. I see almost everything that happened in 4Q as one-time factors that departed from the norm. Hence, as I said, one of the things that—it's an obvious question for me to ask as well as I'm going through all this. One of thing I wanted to be clear in my mind was if you bridge back to normalize levels of funds flow from operations and that, what is the bridge? The bridge was really around the Lima downtime. As I said, we had planned for \$90 million of that. We got an extra \$90 million because it was extended. Then the lower U.S. crack spread was about \$120 million. At the moment crack spreads, they come up off the bottom, but there's certainly going up and down with this different views of the virus situation. It's too early to call the view that they're going to be lower throughout the year or something.

Severance costs were all one-off items, and the Keystone outage, the force majeure on the Keystone Pipeline, I'm hoping we don't see that again as well.

The other little thing that was in 4Q that we didn't explicitly bridge to in previous comments was just that, there's always a time lag as we see the differential narrowing or expanding in our operations the way the Integrated Corridor works. In this case, we saw the differential expanding, so we lost some of the income from the upstream, but of course, it didn't get replaced in the downstream.

In addition, because of the Keystone Pipeline outage, but even where some of that will flow through in the first quarter, we estimated that, of around \$20 million. It would have been larger except for the Keystone issue. Those all felt like one-off sort of issues. When I look back at the guidance for this year, I think it really comes down to price and margin at the moment that has a potential.

There is the Terra Nova offstation which was budgeted in the plan. It's budgeted for about seven months, so it is quite extensive in the budget for this year. We didn't expect it to be shut down for the first month or two prior to going off stations. We'll see if the operator's able to recoup a little bit about, but we're only 13% of that project, so it isn't a major impact one way or another.

I guess the answer to your question is there isn't any. It's really about price and we'll see how that plays out as we go through the year.

Phil Gresh:

That's really helpful. You obviously called out some first-quarter headwinds, but from your perspective, it sounds like nothing that would make you uncomfortable for the full-year outlook or guidance on production.

Robert Peabody:

I think on the fundamentals, like on the controllables, I'm feeling pretty good. I wish the year started a little bit better on the pricing front, but we'll see how that plays out.

Phil Gresh:

Okay, thank you.

Operator:

Our next question comes from Emily Chieng of Goldman Sachs.

Emily Chieng:

Hi, guys. Thanks for taking the time. Just maybe coming back to the capex piece of the equation, and just wanted to dig a little deeper into West White Rose. I believe when this was sanctioned, it was about a \$2.2 billion project net to Husky. Can you remind us exactly where we're standing in terms of spend so far, and how much maybe we should be budgeting for 2021 and '22, given that, I think we should be coming to the tail-end of spend there, please.

Robert Peabody:

Yes. Emily, what we've done here, let me first say one thing. The price of that project hasn't changed since our Investor Day last year. It hasn't changed in over a year, but it hasn't changed since the Investor Day last year. In fact, it's been tracking, if anything, slightly better than what we set out at the Investor Day last year. All the capital that we included, all the capital we put in Investor Day that we outlined at our Investor Day last year included the full cost of West White Rose along with the current estimates.

None of those estimates change on anything to do with West White Rose, and when we said in our guidance call this year that we were going to bring capital down from those levels by \$100 million and \$400 million next year, that also reflected the current status of West White Rose. So all those numbers are still current.

As I said, we're still—we believe and we'll look at the pricing environment this year, we know we have further capital flexibility if we need to pull it this year in order to just ensure we can preserve the funds from operations, in order to sort of bridge the dividend payments and maintain our debt levels as we move into next year when we should see much more room around the extra free funds from operation that we have to support the dividend.

Emily Chieng:

Got it. That's helpful. Thanks. Just one follow-up and this might be a little trickier to answer, but just on the I&M segment, can you quantify how much of the miss might have been due to the Keystone outage versus the differentials?

Robert Peabody:

Do you have that Jeff?

Jeff Hart:

I don't have the specific numbers up here, but basically, the way to think of it, the vast majority of it really is the quarter versus quarter, the narrow location differential. In order of magnitude, the outage did cost us money, but it really is the way to think about it is the location differential primarily, and then that was compounded by the outage.

Emily Chieng:

Got it, that's helpful. Thank you.

Operator:

Our next question comes from Mike Dunn of Stifel FirstEnergy.

Mike Dunn:

Hi. Thanks, everyone. Two questions from me, and apologies if I missed the details in the prepared remarks.

But, regarding the impairment at West White Rose, just looking for a bit more detail on that folks. Your partner had recorded an impairment on the asset in their Q4 report a few weeks ago. I believe what I understood from that was it was an increase to the post-startup cost assumptions for the project. I know that the impairment was based on 3P reserves, or the impairment test is based on 3P reserves, the possibilities aren't disclosed. So, just wondering if there's any changes to the 3P outlook for West White Rose?

Jeff Hart:

Yes. So, it's Jeff here. The colour on that is that the majority of it really is price — every company has their own process that they run. But for us, inclusive of White Rose—and I'll remind you, it's not just West White Rose, it's the existing lands and everything that runs through the SeaRose FPSO. So, you can't look at it in isolation and view it as just West White Rose. It really is the entire White Rose CGU, and the way to think about it really is price-related and price driven, and we haven't this year seen substantive movement in the reserves.

Robert Peabody:

Either any have approved or the probable. They are all very similar.

Mike Dunn:

Okay, thank you. Then secondly, I'm just wondering if you could provide an update, I don't have much of an update, with regards to the status of GHG taxes in Saskatchewan, and with the federal government's trying to apply those, any sense of what they might be for your Company if let's say if there was a similar policy to Alberta's. I think you're not paying those yet, but maybe if you can just provide an update there.

Robert Peabody:

I'll let Janet give you a brief answer on that. We can always get back to you with more detail.

Janet Annesley:

Yes. Hi, it's Janet Annesley here. So, Saskatchewan has a large emitters program, very similar to Alberta. Our facilities are covered under this large emitters program. We'd be very glad to follow up with you. I don't have the quantum of carbon taxes that we're paying if that's your question. But we can certainly walk you through the methodology that is applied to the facilities.

Mike Dunn:

Okay. Great, and then Janet, did these payments just start this year or were you subject to them prior to this year?

Janet Annesley:

They just started this year.

Mike Dunn:

Okay. Yes, I'll follow up with somebody later. Thank you.

Operator:

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

Matt Murphy:

Hi. Thanks. Good morning. Just wondering on the 29-1 extension, if you could remind us; one, I guess if the pricing structure has been settled, what sort of area code that it shook out in, or if perhaps it's still under negotiation. Any comments on where we should be thinking relative to existing pricing?

Robert Symonds:

This is Rob Symonds. So, 29-1, the pricing is fixed. I believe we put that out to you a little while ago. About 10% less than the numbers that you see from the existing contracts. It is set, it's signed, and so no issue from our perspective.

Matt Murphy:

Okay, thank you. I guess on Liwan as a whole, could you remind us when the current price contract or just general contract is due to end? I think 2021 is the timeframe, if I'm not mistaken.

Any thoughts on any discussions that you've held thus far with the operator of that project on potentially extending that contract longer-term. Thanks.

Robert Symonds:

So, that contract is a life-of-field contract. There is as you note a price reset point in, I believe the end of 2021, when we will go into a collared arrangement and I think again, what we've talked about historically is you should think about—and it's based on Guangdong City gate. As Guangdong floats, we will go down no more than \$2, and we will go up no more than \$2.

Matt Murphy:

Great, thanks very much.

Operator:

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

Our first question comes from Alex Bill of allNewfoundlandLabrador.

Alex Bill:

Hi there. Somebody asked my West White Rose impairment charge question earlier, but I'm wondering if you can provide more details on reductions in capital investment in Atlantic Canada as mentioned in the MD&A.

Robert Peabody:

Hi Alex. This is Rob. So clearly we're moving ahead with West White Rose, and so there's no significant reductions associated with that. As we went through last year, we did have some capital invested in a potential sort of Northwest White Rose, some early work around that. We actually pulled that back with the kind of commodity price assumptions we were looking at, at the moment. But the major capital investment we're rolling forward with is continuing.

Alex Bill:

My other question also regards the question on these statements from your partner on West White Rose made earlier this month regarding concerns over overspending at West White Rose.

Is that something you feel has been addressed from the switch to a sort of aggressive schedule basis to this cost-efficiency basis, or would you kind of contest the overspending description?

Robert Peabody:

Well, I think actually even our partner actually said they were satisfied that this was now progressing very well. I think their message was consistent with our message, which was that in the early days of the project, there was some low productivity in that, which we addressed when we kind of re-worked the schedule. Since then, we've been seeing actually excellent productivity by the workforce out in Newfoundland. We've been very happy with the crew on site in the progress we've been seeing. I know our partner shares that view as well.

So, that's where we are now. As I've said earlier, that the kind of cost estimate for the project hasn't changed in over a year, and from a Husky point of view, we've been—in all our analyst presentations and everything, we've been using the same price forecast for over a year.

Alex Bill:

Okay. Thank you.

Operator:

Our next question comes from Rod Nickel of Reuters.

Rod Nickel:

Hi. Thanks for taking my question. Rob, I'm just wondering if you can flesh out a little bit more about why Husky has, I guess, a more pessimistic view of oil prices being lower for longer than it did before. Then just secondly, Teck came out of course with some concerns this week about there being unresolved debate between climate change concerns and energy growth. Wondering if you can maybe give us your thoughts on that issue that they raised.

Robert Peabody:

Super. Okay. Well, I think in terms of oil price, I'd just say that we don't have a crystal ball. I've been in this industry a lot of years. Almost whenever everybody has a consensus view of oil price, it always turns out to be wrong. I guess the good news there is everybody's consensus view is low at the moment. In the past, low prices tend to be the solution to low prices.

We might be going through that again. But all we do with oil price is, when we set the numbers, we basically look at the forward strip. That's all we did when we looked at our guidance for this year. We looked at the forward strip and at the time, that was consistent with long-term flat Brent price of around \$60 and a long-term WTI, flat price of about \$55. So, that's what we used, but I wouldn't want anybody attaching too much importance to our view of it because I haven't seen much fidelity in anybody's views of being able to predict this stuff.

In terms of the Teck decision, I think the only comments I'd make there is, companies cannot control commodity prices. But regulatory processes are in the government's control and governments should make every effort to ensure that companies in any industry don't invest significant dollars in project applications only to be derailed by policy or political uncertainty at the very last moment.

We've seen a whole string of projects here, to some extent in the U.S., but worse in Canada, where people have proponents to spend a billion dollars or more before they get a negative decision from the government to go forward. That certainly is a situation that has to be rectified if people want projects to move ahead.

I think the other comment I'd make specifically more to Canada than even the U.S., is that we absolutely expect that large projects need to undergo detailed regulatory reviews to ensure they meet higher environmental standards. And certainly the Teck project seem to do that, while creating jobs, taxes, and other benefits, really net benefits, for Canadians and the country. I think what we see in Canada is a regulatory process that just takes so, so long and it has an unpredictable length, and that's what we have to get on top of. Because as anybody who's very close to business, all you got to do to frustrate large project investment is if you make the regulatory process take longer than five years, say as a nominal point. The stars that need to align for businesses that often have partners that also have to be aligned on the idea of a large investment, those stars rarely align for more than four or five years.

So, some people, they try to point fingers . . . ultimately in the Teck process, what killed Teck? But what killed Teck ultimately was a regulatory process that just went on and on and on and on.

Had that process concluded in a sensible timeframe, I'm sure we'd have a Teck project under construction today because there were proponents that were set and keen to move forward with that project. But, if you wait long enough, that coalescence on the idea of spending that sort of money eventually unravels. That's what we're seeing.

So, I think the number one thing we need to address is ultimately around the regulatory process to tighten up timeframes and to put more certainty in it, while not giving away any of the requirements that projects have to meet very high standards and be in the interest of the country.

Rod Nickel:

Great, thanks very much.

Operator:

Our next question comes from Dan Healing of the Canadian Press.

Dan Healing:

Good morning. Thanks for taking my question. I was just wondering about the rail blockades. I realized Husky doesn't use the rail to move a lot of oil. What kind of impact are you seeing on that front, and also in being able to access products that you need for your operations?

Robert Peabody:

Yes. I'll just answer that at a high level. We don't use the rail very much because we have good pipeline access, because of our history of investments and commitments on pipelines. So, it's not a big issue for us as a Company. But that said, eventually we have asphalt to move on rail later on in the year, and things like that, and we certainly hope that the government takes the required actions to ensure that the infrastructure of Canada works properly. That's kind of where we are.

Dan Healing:

Okay. I just have a follow-up question on Teck. In view of the situation there, and you're saying that it's related to the regulatory process, do you think that means that large oil sands projects can't be built in Canada right now?

Robert Peabody:

I'd hate to draw that conclusion necessarily. I actually think the issue is far more about all projects in Canada. I think people are attaching this to Teck, but I think building major highways, building pipelines, building major infrastructure projects around cities and things like that, I think this applies to everything. So, I wouldn't draw the conclusion that it's really an oil sands issue.

Certainly, it's a concern, I think when you think about the renewable energy agenda, because renewable energy requires things like wind farms that also contribute, and are also quite controversial at times. Hydro projects are key part of Canada's energy picture. We actually generate more power from renewable sources than most countries in the world because of the huge hydro positions we have. And as we've seen in this country, if you want to increase the size of that source of power, that's also a big issue.

So, I think this is interesting. It was Teck, it was an oil sands project, but I think it's just endemic of a much bigger problem.

Dan Healing:

Okay. Thank you.

Operator:

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

Robert Peabody:

Well, thanks, everybody for taking the time today and thanks for your questions. We'll release our 2020 first quarter results on Wednesday, April 29th. Following the call, we'll hold our annual meeting of shareholders in Calgary. So, thanks again for calling in today.

Operator:

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