HUSKY ENERGY

2017 INVESTOR DAY WEBCAST

TRANSCRIPT

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Speakers:

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President and Chief Executive Officer

Jon McKenzie
Chief Financial Officer

Rob Symonds
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Vice-President, Downstream Value Chain

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Chief Operating Officer, Asia Pacific

Malcolm Maclean
Senior Vice-President, Atlantic Region

JANET ANNESLEY:

Good morning everyone. If I could just ask everyone to find a seat, if you haven't found one already. Good morning and thanks for joining us today. I'm Janet Annesley, Senior Vice President of Corporate Affairs. I'm new to Investor Day, having just recently joined Husky, and these are certainly exciting times to be with the Company and over the next few hours I'm sure you'll see why.

Before we get started, just a few housekeeping items. All emergency exits are clearly marked. In the unlikely case there is an emergency, please look for the staff to guide you, and if you could please check your cell phones and turn them to silent.

Now, about today's agenda. Rob Peabody will start off the morning with a look at our five-year plan. He'll be followed by Jon McKenzie who will lay out the financial framework. Then Rob Symonds will provide an overview of our Integrated Corridor. This is the business that runs from Fort McMurray through Lloydminster and includes all of our Midstream and Downstream assets. Andrew Dahlin is our newly promoted Senior Vice President of Heavy Oil and he will get into our Thermal business in more detail. Jeff Rinker, Husky's VP, Downstream Value Chain who joined the Company recently from OMV, will show how we continue to enhance this part of the operation. Gerald Alexander, who is our new Senior Vice President of Western Canada, will give an update on how this business looks post transition. Bob and Malcolm will then speak to our Offshore business.

To know who's who, all the bios of Husky's Leadership team are at the back of your materials, along with a detailed appendix that includes our price planning assumptions, project economics, reserves information and all sorts of other nuts and bolts. A couple of quick reminders about that information: this presentation of course includes forward-looking information and unless otherwise stated, everything today is in Canadian dollars.

All the presentations together will take about two hours. There will be one break about 40 minutes in. We'll take questions from the floor at the end before we go for lunch. All the speakers today plus additional members of Husky's Management team are here and will be happy to chat with you on a less formal basis over lunch.

Now, I'll turn the floor over to Rob.

ROB PEABODY:

Thanks, Janet. Welcome everyone and thanks for spending the morning with us. You're going to see a number of new faces today as Janet kind of led into, with my promotion and with Rob Symonds' recent move up to the COO position, so that allowed us to create some good opportunities for a lot of people in the Company. I think you'll see that we have a strong team in place with the energy and drive to take Husky forward. You came here to see what's ahead for the Company so let's get started with the headlines. I'm a finicky person about pictures, too …

These are the main outputs. Our pricing assumptions are covered in more detail in the appendix, but at a high level our plan is based on an oil price of US$50 WTI this year, moving to $55 in 2018 and US$60 in 2019. With AECO at CA$2.50 this year and $3.00 thereafter. Over the next five years we see average production growth of about 4.8% annually, approaching 400,000 barrels a day in 2021. More importantly, funds from operations grows at a compound rate of 9% a year, going from about $3.3 billion this year to about $4.8 billion in 2021. Free cash flow grows at an average rate of 12% per year to about $1.2 billion in 2021.

So, while we're growing production, funds from operations and free cash flow are growing at much higher rates. This is being driven by investments that further reduce our cost structure and improve the cash generating abilities of our asset mix. By executing our plan and sticking to our strategy, we expect to see improvements on sustaining capital requirements and breakeven pricing metrics. Annual sustaining capital averages $1.9 billion over the plan, which is a 40% improvement since 2014, and down about $600 million since we spoke to you last year around this time.

Over the next five years, our earnings breakeven trends towards a U.S. WTI price of $37 per barrel, and the oil price we need for cash breakeven, which is the oil price we need to cover sustaining capital, averages just over US$32 WTI.

Over the five-year plan we expect to generate funds from operations of about $21 billion, capital spending over the same period is expected to be about $16 billion, which includes about $6.5 billion in growth investment capital. This means we generate an aggregate of about $5 billion in free cash flow over the period. So, if you've got that, we'll drop down a level.

We are two businesses, an Integrated Corridor and the Offshore. Both are competitively advantaged in many ways. They're both growing. They're both generating free cash flow, and they're both low cost. In the Corridor, our latest Lloyd thermal projects have operating costs in the $8 per barrel range, and in the Offshore business, operating costs run anywhere from about $6 per barrel of oil equivalent in Asia to about $14 per barrel in the Atlantic. In addition, each of these businesses have built-in measures to mitigate volatility.

Along the Integrated Corridor, we are able to capture the best margins because we own and operate the assets along the way. They're largely shielded from the heavy-light and Western Canada location differentials by balancing Upstream production with Downstream throughputs.

Offshore, our Asia projects have the advantage of fixed price contracts. They're not impacted by swings in commodity prices.

Both businesses offer many attractive return opportunities with plenty of room to run.

I'll start with a more in-depth look at the Integrated Corridor. You'd be hard-pressed to find a grouping of assets that is as tightly integrated with so much potential. It includes our thermal production, our Lloyd upgrading and refining complex, the midstream partnership, and our refineries in the U.S. Midwest. It is also supported by our Western Canada natural gas production, which provides an internal hedge for our thermal and refining energy needs. Although we produce a lot of heavy oil at the top of this corridor, we really consider ourselves more of a manufacturer of refined products: jet, gasoline, diesel, asphalt, synthetic oil and more.

In Q1, we produced the equivalent of 305,000 barrels a day of upgraded and refined products. The reason this business is advantaged is that its assets are physically connected. This gives us the most potential to maximize margins. It also mitigates product and location differentials as I mentioned before, and provides secure access to U.S. markets.

We've been busy in the Corridor over the past year. We accelerated our thermal production by bringing on three new Lloyd thermal projects and continued to ramp up Tucker and Sunrise. Total thermal production is now more than 120,000 barrels a day and that's up about 50% since this time last year. The Rush Lake 2 project, which is a 10,000 barrel per day nameplate capacity project, is under construction. We are progressing an additional 30,000 barrels a day of new Lloyd thermal capacity, which is set to come on in 2020. Andrew will give you some more colour on that in his section.

In the Downstream, we've been making investments to grow margins by increasing our heavy crude processing capacity. Jeff will talk about some of the more interesting ways we're improving flexibility across the entire value chain to enhance our value capture.

In addition, we've created a new midstream partnership that not only meets our increasing takeaway capacity needs; it is a growing third party transportation business in itself.

In Western Canada, the portfolio has been refocused. We have achieved a step-change reduction in sustaining capital and the business now is much less complex. An example of this is the number of wells has been reduced from about 18,000 a couple of years ago down to around 8,000 today. This has materially reduced our long-term reclamation liabilities, and we are driving capital and operating efficiencies in the remaining portfolio so that future capital investment can earn higher returns at our price planning assumptions.

We're seeing better and better results at Ansell, and in the Wilrich. A little bit later Gerald will provide some details on this as well as our emerging Montney position.

Moving now to the Offshore business, we have a competitive advantage in both the Asia Pac and the Atlantic. We have deep knowledge of the respective basins, borne out of many years of experience. Both areas leverage off existing infrastructure to drive greater cost efficiencies, and this is going to be a recurring theme that you hear today. We're able to sell our products into both regional and global markets, and we have a strong track record in both Asia Pac and the Atlantic regions for project execution, operations up time and exploration success.

Starting with the Asia Pacific region, our business model is basically to find gas on the doorstep of markets that need it and then pipe it directly into that market at a fixed price. The real story here though is how much free cash flow this business generates. The big project spending for Liwan is behind us and last quarter we saw a $64 per barrel of oil equivalent operating netback in Asia. Our longstanding relationships in this region are also a very valued asset.

In the Atlantic, this business has generated some of the strongest returns in our portfolio over the years. Yesterday, we announced that we're going ahead with the West White Rose project. This is an important project for the business and it's leading the Atlantic region renewal. We'll be using a fixed wellhead platform tied back to the SeaRose FPSO. We've made significant improvements in this project since it was first considered in 2014, and now expect total gross production over the life of the field to be 45% higher than our original estimates. We expect first oil in 2022, ramping up to gross peak production of 75,000 barrels a day in 2025. In terms of capital efficiency, we've seen more than a 30% improvement.

A feature of this project is that the incremental operating costs are expected to be less than $3 a barrel over the first decade. This will drive down overall Atlantic region per barrel operating costs.

As was the case for the original White Rose field, we will be looking to identify additional step-out opportunities.

We made a lot of headway over the past year in the Offshore business as well. At Liwan, the installation of the 22-inch line meant we achieved technical completion of the project. That was important because it triggered the beginning of a 20-year fixed price contract. Offshore Indonesia, the BD Project is currently being commissioned. As Bob will tell you later this morning, this is the first of a series of gas projects we have coming on in the Madura Strait.

On the exploration front, we've been active offshore China in an area that holds good potential. We've signed a PSC for a new shallow water block in the Pearl River Mouth basin, an area where we have operated for years with our partner at the Wenchang field. Malcolm will speak more about the Atlantic exploration progress in his section, however, I'll just mention that yesterday we also announced a new discovery at Northwest White Rose. This underpins the point I made earlier about additional step-outs being identified that have the potential to be tied back through West White Rose and the White Rose facilities.

Let's get into how both of these businesses perform, starting first with production. Over the next five years, the Upstream part of the Corridor will see average annual production growth of about 5% to about 300,000 of barrel of oil equivalent per day in 2021. This growth is mostly driven by lower cost thermals and gas resource plays. In the Downstream, our heavy oil processing, which tends to capture higher margin compared to light oil, will have an annual average growth rate of 8% to reach 220,000 barrels per day by the end of the period, and in the Offshore, we will see a production CAGR of 4.3% to over 90,000 barrels of oil equivalent per day. This is mostly coming from our projects in Indonesia and the next phase of Liwan at 29-1.

Combined, production is going from about 330,000 barrels per day to approaching 400,000 barrels of oil equivalent per day in 2021, an annual compound growth rate of just under 5%. While production growth is important, today we're going to focus on funds flow from operation and free cash flow generated by that production.

Here's a look at the free cash flow profile for both segments, using our 5-year planning price assumptions. In the Integrated Corridor, funds from operations have a CAGR of 11% and free cash flow increases every year. In the Offshore business, it's really a steady and strong free cash flow that we see. It completely self-funds the West White Rose project, plus it generates significant free cash flow averaging more than $500 million per year. The figures in these charts are all after tax but before allocating corporate costs.

Let's put the two businesses back together again. They have smoother capital spending, funds from operations and free cash flow profiles. The result is growth in funds from operations and a CAGR of 9% with a free cash flow CAGR of 12%. Cumulative free cash flow generation over the five-year plan is $5 billion and that's all after corporate capital.

The quality of our investment portfolio allows us to continually improve returns over time. Overall, the growth, the goal is to drive down our earnings breakeven oil price. Over the next five years we will go from the mid-40s US WTI where it is today to the mid 30s, and here's how we do that.

We start with a deep portfolio of investment opportunities with low breakevens. The more we invest in these opportunities, the more we improve our cost structure and margin capture. This in turn reduces both our sustaining capital requirements and the oil price we need to break even. This increases margins, meaning our funds from operations—as our funds from operations go up and we improve free cash flow for every barrel we produce and process into finished products.

We are then able to use this cash to establish a sustainable dividend and re-invest back into the portfolio to kickstart the cycle again. So, let's drill down on some specifics.

The quality and size of our portfolio of growth projects mean that we can set aggressive hurdle rates. Every new investment must make a 10% return at US$45 per barrel flat WTI, and it must break even at US$35 WTI. Being disciplined about holding this line is what drives down our cost structure. We believe this sets us apart as not many of our peers have a portfolio of projects that can clear these hurdle rates. I'll point out that the portfolio is weighted towards short and midcycle developments, also giving us more flexibility.

We do have projects that don't currently clear our hurdle rates but we have the potential to move the needle on these. Our intent is to keep working them. Examples include looking at smaller, more modular designs for future phases at Sunrise, and advancing technology such as we're doing on the Lloyd block with cold EOR.

Our capital spending continues to improve our cost structure. Our earnings and cash breakevens continue to come down, and there are really three major drivers of this. The biggest single one is the nature of our business has fundamentally changed. This is the structural transformation. An illustration of this, we used to employ more than 40 drilling rigs just to hold production steady. Now it takes less than 10 rigs worldwide to both sustain and grow our production, and I noticed many of our peers are moving in the opposite direction.

The second driver is working with suppliers and partners to come up with better ways of doing things and bringing costs down.

The third driver, which we've seen recently, is the U.S. and Canadian dollar exchange rate. Most of our revenue is denominated in U.S. dollars, though the bulk of our costs are in Canadian dollars.

Looking out over five years, sustaining capital goes from about $1.8 billion up to $2.1 billion in 2021 as production grows. However, since we'll be growing our production at a faster rate, upstream sustaining cost per barrel stays pretty constant over the next five years at about $11 per barrel of oil equivalent.

At the same time, the oil price we need for breakeven earnings, which is already low, continues to fall. With the improvements in the asset base, we'll be able to fund our sustaining capital, that's cash breakeven at an average oil price of a little over US$32 WTI.

As we invest and improve our asset base, our margins will expand, which results in growing funds from operations as I showed you before. Funds from operations will grow at a 9% average annual rate over the period, resulting in about $5 billion in 2021. About two-thirds of this growth is due to the improvement in our asset base over the next five years, while the other one-third is from the escalation in our pricing assumptions. Jon will have more to say on that a little later.

This more than covers our capital program, leaving excess free cash flow. We can use this free cash flow to further accelerate investment in our portfolio and establish a sustainable cash dividend, which has room to grow over time. All of this, of course, depends on executing our plan.

These are the projects in which we will be investing and delivering over the next five years. This isn't our entire portfolio but it is what underpins the numbers we are giving you in our five-year plan. We'll update this over time as projects are completed and new ones come to light.

So, those are the headlines and how it comes together. Now, to sum up our value proposition, we are focused on returns. We have a deep portfolio of projects in which to invest. We ensure that all investments generate a rate of return of at least 10% at a flat US$45 WTI oil price. Investing in these types of low-cost projects is improving the performance of our asset base. The oil price we require to break even continues to come down. Our margins are expanding and this enables us to drive strong growth in funds flow from operations and free cash flow.

The nature of our business allows us better manage risk. Two-thirds of our capital over the plan is weighted to short- to medium-cycle investments. We receive the benefits of integration and fixed price contracts. We also maintain the strength of our balance sheet. This means that Husky is more resilient to downside commodity price movements while still preserving the upside. Essentially, we aim to deliver a better risk-adjusted return.

Now I'll ask Jon to speak to our financial framework.

JON MCKENZIE:

All right, great. Thanks, Rob. Welcome to everybody this morning. It's great to see a number of familiar faces. We really appreciate you coming out and I think this will be two hours well invested.

One of the things my old boss used to insist on when I spoke publicly is that I did up the top button of my jacket. As I age I find that increasingly difficult to do, so I hope you'll indulge me if I don't appear the way Asim would have wanted us to all appear today.

If you've followed Husky for any length of time, this slide would be no surprise to you. Our financial priorities haven't changed from year to year. What does change, however, is the emphasis that we put on each of the different elements of our financial priorities, depending on what's best for the Company and what's best for the shareholders. Last year, emphasis was clearly on reducing leverage on the balance sheet to ensure that our credit ratings remained investment grade and we were not in a position where we needed to do a dilutive equity issue and this was accomplished through a couple of strategic transactions.

But today, the balance sheet is in very good condition by every measure. We're now in a position where we can deploy more capital to fund our inventory of projects and that generate returns at low commodity prices. Funding these projects continues to lower our cost structure and expand our margins. That's very important to this company and very unique to this company.

In essence, we're reducing our earnings and cash breakevens, which makes the Company more resilient at lower commodity prices, and generates more free cash flow through the commodity cycle. This free cash flow can be allocated to additional growth, both organic and inorganic, as well as returning cash to the shareholders when the conditions are right.

Now, Rob has talked to you about our two businesses. Each of them have different value drivers. In the Corridor, it's all about growth, cost control and margin capture up and down the value chain. At Offshore, it's about the high netbacks we're realizing. In the Atlantic, our earnings are levered to oil prices and in Asia Pac we have largely fixed price gas contracts that are not impacted by the oil markets.

Both the Corridor and the Offshore businesses have different sustaining capital requirements. We define this as the capital required to keep all of our assets running a safe and stable condition, and keeping production flat in the upstream. You can see on this slide how we've broken them out below.

In the Corridor we expect sustaining capital to average about $1.5 billion. That's $1 billion for the upstream and about $500 million in the downstream. Offshore sustaining capital will average only about $400 million.

Now, let me provide a bit of context on this. Over the past number of years we've been reshaping our portfolio by investing in projects that reduce our sustaining capital requirements. This year, the number is $1.8 billion, a significant reduction over the past two years, and there's two reasons for this dramatic improvement. First, we've sold some of our higher cost legacy assets and you'll see quite a dramatic slide in Gerald Alexander's presentation about what sustaining capital requirements were and are now in our Western Canadian business.

Secondly, we brought on more lower cost production, including a series of long life Lloydminster thermals.

Looking forward, we anticipate sustaining capital to modestly rise over the plan to about $2.1 billion in 2021, but less than the rate of production growth. This means that Upstream sustaining capital on a unit of production basis will hold steady through our planning period. Now, we've provided more detail and analysis on our sustaining capital requirements in the appendix at the back of your presentations.

Rob has walked you through this cycle a few minutes ago and I'd like to point out that this is also the basis of our financial framework. So, first starting with our focus on returns, and again, this'll be a slide that's familiar to you from Rob's presentation, but a big part of our improvement in our business has been the depth of the portfolio and the quality of the assets. We've established some notable hurdle rates for our investment decisions. Every new investment must generate at least a 10% after tax return at US$45 flat and must break even at $35. Here's what we'll actually be investing in in the five-year plan.

Everything that you see in gold is attracting capital through the next five years. Funding these types of projects is lowering our cost structure. Over the past few years we've sweated our portfolio to increase the number of projects that can clear these internal hurdle rates. These projects—and this is not a complete list—are spread right across the Corridor and the Offshore business. They vary by cycle time, geography and product mix. This means that we can reduce the level of risk in the portfolio and the result is a better risk adjusted return and a higher level of confidence that every dollar we put to work is producing results.

So, let's look at how our capital spending program will further reshape our portfolio and continue to lower our cost structure. In the Upstream, we can see a 17% improvement in operating cost per BOE over the plan. The increasing Upstream netback is a function of both an improvement in the underlying asset mix as well as a rising commodity price assumption, while the 12% increase in the Downstream margins is almost entirely because of improving asset performance. This is a result of the investments we are making to take heavier crude feedstock at Lima and increase our asphalt capacity at Lloydminster.

The main output and goal of all of this is to lower our earning and cash breakevens. The earnings breakeven drops to around US$37 WTI by 2021, and the cash breakeven, which we define as the oil price required to fund our sustaining capital, improves over the plan averaging about US$32 WTI. In a nutshell, we're bringing down our breakevens while at the same time growing the company.

Now this chart shows the assumed pricing that underpins our plan to grow the free cash flow and this is what we're using as a base case through today's presentation.

We have consistently stated our financial priorities: maintaining a conservative, investment grade balance sheet that gives us liquidity and access to capital through the cycle, one. Two, continuing to make investments to transform our asset base to a lower cost, higher margin business that generates free cash flow through the cycle, and thirdly, returning cash to our shareholders. Through 2016, maintaining a strong balance sheet took precedence. As a result, we came into 2017 with increased financial flexibility and strength. We do not anticipate needing to de-lever or issuing equity through our plan as CapEx is comfortably within our cash flow. In fact, as a result of improving capital efficiencies, we revised the 2017 capital spending guidance down by $100 million this morning to $2.5 billion to $2.6 billion.

So, understanding that our balance sheet is strong, our next priority in deploying cash flow is to cover our sustaining capital requirements. As Rob mentioned, this averages about $1.9 billion annually over the plan period. Beyond funding sustaining capital, the plan generates significant free cash flow through the period. There is room for both growth and a dividend, and we don't want to do one to the exclusion of the other; both are important. We have included other cash items here including ARO and capitalized interest. The free cash flow shown here is an all-in number after all cash corporate costs and corporate capital.

On the chart, we've also divided up capital between the spending that contributes to production within the plan period versus the spending that contributes in the 2022 and beyond period. West White Rose falls in the 2022 and beyond category and is one of the only long cycle projects we have. The rest of the 2022-plus capital predominantly is allocated to more growth in our Lloyd thermal business. All of these investments we are making continue to drive down our cost structure, expand margins and deliver increasing free cash flow.

Now, should commodity prices exceed our planning assumptions, we have the ability to modestly increase our capital program as well as return additional cash to shareholders. Similarly, should we cycle below our price planning assumptions, we have the financial strength to maintain our capital program. There's a limit to how much more growth spending we would consider under this plan as we want to preserve the capital efficiencies that we have delivered. In other words, what you should take from this is our bias is to return cash to shareholders. Under our price planning assumptions, though, we can comfortably afford all of our four spending priorities.

The flipside of this, when we execute our capital spending program as planned, the performance of the asset mix will improve, bringing down our cost structure, and as I mentioned, increasing our funds from operations. But to demonstrate the improvement in our asset base, we've held our oil price assumption on this slide flat at $50 WTI over the five-year plan. This isolates the impact of the escalating commodity price assumption and really demonstrates the impact of our improving asset base. At US$50 we can fund our entire growth capital spending program—again, this is showing all-in cash capital—and still generate $1.3 billion in cumulative free cash flow over the five years.

In 2021, the funds from operations the Company would be able to generate is 30% higher than today with the exact same macro assumptions.

This is an important slide, and I often get asked the question about why we've geared this company to $4 billion. One of our goals is to build a company that is resilient at the bottom of the cycle. This means that at the bottom of the cycle we should be able to, one, stay below 2 times debt to cash flow; two, be able to fund our sustaining capital and maintenance capital requirements; and three, still have some discretionary income left over.

Recent experience would suggest that at the bottom of the cycle it's about US$35 WTI. We don't believe that prices could stay there indefinitely but we do envision a scenario where prices could cycle down to $35 for a period of time. If that were to happen with the asset mix that we have today—you'll see this to your left, to my right—we'd still generate about $1.9 billion of funds from operations, which is enough to cover our current level of sustaining capital and still have about $100 million in discretionary capital left over. This ensures that we remain at less than 2 times net debt to cash flow, our credit rating stays largely intact and we don't have to make any sudden moves like rising equity or selling assets.

As we execute the capital spending program in our plan, it improves the quality of the portfolio. So if I did the same calculation using $35 WTI, $12 Chicago 3-2-1 crack, in 2018 I would have not $100 million of discretionary cash but $500 million, in 2019 that grows to $800 million; in 2020 that grows to $900 million. Finally, in 2021, at an assumption of US$35 WTI and a $12 Chicago crack, we would generate $3.1 billion of funds from operations, which can cover our expected sustaining needs to $2.1 billion at that time and still have excess $1 billion to deploy towards growth and the dividend. In terms of the balance sheet, we would have the flexibility to go up to about $6 billion of net debt and stay below our threshold of 2 times net debt to cash flow.

To sum up, our five-year plan provides for growth that is focused on returns while at the same time lowering our cost structure. All of our spending priorities are covered under our price planning assumptions. Our capital program contributes to improved margins and increased free cash flow, and this in turn can be used to accelerate growth and establish a sustainable cash dividend. And we can execute this plan without increasing our leverage or compromising our already strong balance sheet.

Rob and I have talked for about 40 minutes, so why don't we take a 10 minute break and reconvene at 10:50. Thank you very much.

(coffee break)

ROB PEABODY:
Okay, we'll start again in about 30 seconds to a minute.

I hope everybody had a chance to stretch their legs during the break, and if you went to the washrooms you've certainly had a chance to stretch your legs.

Before we get started with an overview of our operations I wanted to note that the environment, social responsibility and governance are paramount in all facets of our company. We strive to deliver essential products to the world in a safe and responsible manner, and we're doing just that.

In terms of safety, we are continuing to strengthen our safety culture with a focus on process and occupational safety. To us, safety is more than a line on a chart. We believe that good safety is good business; it goes right to the bottom line, as I've said many times before.

On the environmental front, we operate in some of the most tightly regulated jurisdictions and countries in the world. We have rigorous emission controls in all our operations, and we're working to advance several technologies to further improve our operations and continually reduce our environmental footprint. This includes piloting new carbon capture and injection technology in Lloydminster. You're going to hear more about these in Andrew's section of the presentation.

We're supplying natural gas to Asia which is displacing more carbon-intensive sources of energy like coal, and improving air quality. If any of you have been there, you know that's a key priority for the region.

We've been upping our game in terms of ESG disclosures. We continue to increase the amount of financial quality metrics on which we report, and we're going to continue to do that. Most of these metrics are disclosed in our annual Community Report which will be published soon. By tracking and measuring our progress, we are holding ourselves accountable, both to our shareholders and to the broader community.

The increased level of disclosure is making a difference. For example, we were added to the Jantzi Social Index in 2016. In fact, we'll be back in Toronto in a couple of weeks attending a financial industry ESG conference.

Now, I'm going to turn the floor over to Rob Symonds who will provide more insight into our operations, starting with the Integrated Corridor.

ROB SYMONDS:

Thanks, Rob. Earlier this morning you heard Rob talk about us having two businesses and I'll be talking about one of them, the Integrated Corridor.

Before we get into the details of the Corridor though, I want to talk about the midstream deal that we closed last year. We had three conditions that had to be met for that deal to happen. The first was we had to get fair market value and it had to be material. Well, the transaction went through at 14 times EBITDA which equated to $1.7 billion net to Husky. Next, we had to maintain operatorship and control of the assets; that was absolutely core to us. The 35% interest we retained means we remain committed to the midstream business and we've preserved our position at Hardisty. Finally, we needed an aligned partner who wanted to grow the business in lockstep with our thermal growth, and who also of course had the financial capacity to do so. The deal we have gives us takeaway capacity for at least eight additional Lloyd thermals.

So we fulfilled all three of the conditions with the Husky Midstream Limited partnership. The Partnership is a growth vehicle with a low cost of capital. The Partnership has committed to spend $750 million for growth projects. There are three projects I'd like to draw your attention to. The South Saskatchewan Gathering Line was completed last year. Secondly, we are underway with the LLB Direct Pipeline which will come on in 2018, and thirdly, we've also started work on the Northern leg. These projects are accommodating our own thermal growth but they're also increasing the size of our third party transportation business and certainly we continue within the Partnership to continue to look for other expansion opportunities. So, you're going to be hearing a lot more about this section of the Corridor in the years to come.

Now we'll have a look at the entire Corridor, and I'll start with our Upstream position. On the Lloyd block we have a total of 2.2 million acres with about every second section held as freehold acreage. What that means in our case is we pay zero royalty on that land. At Tucker, we have decades of production ahead of us in the Cold Lake region. Sunrise, we're making good progress on our Tier 1 asset there. Production now is at approximately two-thirds of capacity, and once ramped up we have a massive resource base there with ongoing low F&D classes. In fact, we could sustain 60,000 barrels a day for more than another 100 years and I certainly won't be up here talking about that. In our resource plays, we have more than 450 potential drilling locations in the Wilrich play, and we also have an emerging position in the Montney where we hold about 150 net sections, and Gerald will give you a bit more information on that in his section. The gas produced across this portfolio provides an internal hedge for us by supplying the thermal projects and our refinery needs.

At the top of the Integrated Corridor, we have about 260,000 barrels of oil equivalent per day of production, and that includes, today, 120,000 barrels of thermal bitumen.

As mentioned earlier, what makes this business unique is that the entire Corridor is physically connected, from the field to our Lloyd Complex, through our midstream, transportation and blending assets, and down to the refineries in the U.S. Midwest. In Canada and at Lima, we control or operate these assets.

Why is physical integration so important? It means we can move quickly to maximize margin capture every step of the way. So, basically, we have our fingers on the buttons, and again, Jeff will give you a lot more detail on some examples of that in his section.

We also have a deep inventory or projects in which to invest. In the Upstream, our focus is on short- and medium-cycle projects like our Lloyd thermals and Western Canada gas resource plays. As you know, last year we brought on three new Lloyd thermals. They had an average capital efficiency of about $25,000 per flowing barrel. They have operating costs at $8 a barrel, and their initial steam-oil ratios were 2.2.

Now, we expect to see similar performance from the next 40,000 barrels a day of nameplate capacity at the projects that are now underway. Those projects are Rush Lake 2, Dee Valley, Spruce Lake North and Spruce Lake Central. Rush Lake 2 will come on in 2019 and the other three will come on in 2020. You should think that in 2021 and beyond we'll be looking to bring on an additional two projects each year for the future years.

At Tucker, we're on our way to the design capacity of 30,000 barrels a day, and under our pricing assumptions, Tucker generates average free cash flow of $200 million a year over the five-year plan.

At Sunrise, clearly Job 1 is to get to full plant capacity of 60,000 barrels a day. In a few minutes, Andrew will talk about how we're going to get there.

In Western Canada, our resource play business has been rejuvenated. The asset sales are largely complete and with an ongoing large inventory we have lots of flexibility to dial up or dial down capital as required.

In the Downstream, we're making investments in a couple of important areas. We're increasing our heavy processing capacity at Lima and we're evaluating the potential to double our asphalt capacity at Lloydminster. Engineering on that project is underway and a final investment decision will be made next year. We're looking at the Downstream business in a different light: to find ways to capture more value, and Jeff will walk you through that shortly.

The other Rob already showed you this cash flow profile for the Corridor. As you can see in the chart on the right, over the next five years we will generate over $16 billion in funds from operations. Capital spending in the Corridor over this same period will be about $12 billion, leaving about $4 billion in after tax free cash flow before corporate costs.

So, what's driving this value? Well, it's longer life, lower cost thermal projects which are replacing higher cost legacy production. We're also increasing our ability to process heavier oil feedstocks to capture wide margins in the Downstream. And in Western Canada, we've repositioned the portfolio to focus on resource plays that are economic in their own right at today's prices. With the structural transformation well underway, only about 60,000 barrels of oil equivalent or 20% of our overall upstream production is not attracting growth capital, and this includes about 40,000 barrels a day of CHOPS production in the Lloyd area and 20,000 barrels a day of legacy assets in Western Canada. But declines in that production are being more than offset by higher value production growth.

Perhaps one of the most compelling aspects of our portfolio is the competitive position of the Lloyd Refining Complex. It all starts with Lloyd and Tucker thermal production. Op costs are low, averaging about $10 per barrel in Q1 of 2017. Now, this low-cost feedstock sits right at the doorstep of the Lloyd Complex. As a result, there's low transportation costs which usually run in the range of $3 per barrel. All of the costs quoted here are on a non-blended basis as diluent circulates, as you can see on our little graphic here, through the system in our loop.

Now, the next step is to transform that feedstock into bankable products. We can turn the oil into either synthetic or diesel or asphalt and we can do that for an additional $8.50 per barrel. We've been working these costs down with the help of new technology, as well.

The Lloyd Upgrader produces high quality products. One is sweet synthetic or HSB. HSB fetches a higher price than other streams and competes with similar grade crudes from the Bakken and the U.S. Gulf Coast. We make about 55,000 barrels a day of HSB. Then there are other products that currently fetch an ever higher price than HSB and these would include products like ultra-low sulphur diesel.

The Upgrader can, to a degree, swing between these products depending on which is offering the highest returns. It also produces high-quality reformer feedstocks including naphtha and diluent products that have been upgraded from the intermediate feedstocks that come from the asphalt refinery. By the way, the Lloyd crude makes some of the highest quality asphalt in the world. It's often used as a blending agent by other producers who want to bring up the quality of their own product. Our asphalt is shipped across North America via rail and is distributed through our extensive terminal networks.

As I mentioned, the asphalt plant also produces intermediate feedstocks which can be sold directly in the market or sent to the upgrader for further processing.

Now, the blended average realized price for all the products produced at the Lloyd Complex in Q1 was, as you can see on this slide, $64.50 a barrel. The configuration of the Lloyd Complex also gives us a higher product yield than many of our peers. We typically run about 98% yield, whereas less complex upgraders tend to run closer to 80%. So not only do we have a higher priced product but we're also able to sell more of it. And all of this production has an extensive market of local buyers and so that provides us a choice of either selling locally or exporting further afield.

So, all in all, in Q1—and I direct you now to the left side of this slide—we captured a very competitive netback across the entire value chain of about $40 a barrel, and that's an additional $15 a barrel versus had we sold that same oil at the wellhead.

That was the Lloyd Chain. Now let's talk about why we like the Sunrise to Toledo value chain. We are configured so that we can transport Sunrise crude directly to our 50% owned refinery at Toledo and turn it into gasoline, diesel and distillates. There's no need to upgrade before entering the refinery as the Toledo high-TAN project, which was completed last year, allows for the processing of the dilbit that we deliver. So in addition to skipping the cost of upgrading, once again, there is no volume loss. Like the Lloyd Complex, Toledo has high refined product yields, in this case slightly over 100%.

Again, if we look at Q1 of 2017, you can see on the chart we realized a refined product price that translated to about CA$78 a barrel.

For illustration, if we assumed a $12 operating cost for Sunrise, which is what we expect it to be when we reach capacity, and taking into account typical transportation, blending and refining costs, in Q1, had we been running at capacity, we would have realized a $35 netback per barrel, and that's a value capture of about $25 a barrel additional to the netback that would have been available for selling that crude at the wellhead.

Now, this chart illustrates how we're improving the quality of the production and throughputs along our Integrated Corridor. Heavy oil is improving through the addition of more low-cost, long life thermal projects. Downstream is making more money by increasing the amount of heavy that we can process. The conventional business in Western Canada is replacing legacy production with higher quality resource plays.

To bring it all together, this is contributing to bringing down our cost structure. We expect Upstream operating costs in the Corridor will drop about 20% over the plan period. Sustaining capital will average $1.5 billion per year over the next five years. While it will also rise over the period, production will also rise, resulting in a steady, sustaining capital per barrel number, and Downstream realized margins are expected to rise about 12% over the plan as we continue to heavy up.

That's been a look at the Integrated Corridor. All together, we're anticipating annual production growth of 5%. We'll see over $16 billion in funds from operations and about $4 billion in after tax free cash flow.

In the Upstream, we will continue to focus on short- and medium-term opportunities, while in lockstep improving our heavy oil processing capacity in the Downstream.

Andrew, Jeff and Gerald will now walk you through the different facets of each segment to show how they are contributing to higher margin production and free cash flow generation. Thank you and over to Andrew.

ANDREW DAHLIN:
There's a height thing going on. Good morning everyone and thank you, Rob.

I'm one of the new faces that Rob spoke to this morning, and whilst I've been with Husky for six years, this is indeed my first Investor Day. Coincidentally, it was also my first Blue Jays game over the weekend, and you've seen the results so obviously I'll be coming back for more of those games.

Now, I'm originally from Norway and I grew up with a view of the North Sea from my bedroom window, so such you'd think that I'd be best suited for our Offshore business, but in fact I am very happy to be working our Heavy Oil portfolio.

Over the next 15 minutes or so I want to talk you through this business, and in doing so I want to leave you with two key things; firstly, that this is already a really material and cash flow positive business, and secondly, that we're positioned to grow and drive even further value and cash flow from this business for years to come.

As mentioned by Rob, we've got a deep portfolio of both existing and future thermal projects with assets at Sunrise, in Tucker and at Lloyd. Thermal production is at 120,000 barrels per day today and we're going to deliver 50% thermal production growth over the next five years. The thermal business is expected to generate about $500 million free cash flow this year and as we invest further into this business, we actually increase the margins and then these margins in turn will drive continued growth in free cash flow in future years.

Finally, as Rob spoke to, our assets are physically integrated with our mid and our downstream businesses, essentially allowing us to capture even further margins as our own barrels move down the value chain.

Now, our thermal production, as you can see in the chart, from Lloyd, Tucker and Sunrise is about 120,000 barrels per day, making up about a third of Husky's total production. Over the next five years we're going to grow this another 50%, hence adding another 60,000 barrels per day. As you can see in the production chart on the right, we're expecting this growth trajectory to continue as we tap into our vast resource base and execute projects using our well established formula of repeatable modular designs.

Let me give you some additional insight into this. At Lloyd, our thermals are an important contributor to Husky, both today and going forward. About two-thirds of our heavy oil production is now being generated by thermal technology, and we have a new thermal project underway with construction having started at Rush Lake 2. This project will add another 10,000 barrels per day nameplate capacity in 2019.

In addition, we're progressing a trio of thermals close by at Dee Valley, Spruce Lake North and Spruce Lake Central. They will come online in 2020 and they'll add another 30,000 barrels per day of total nameplate capacity. Beyond this, we have 14 more Lloyd thermals in the wings.

Now, at Tucker, we're currently at 23,000 barrels per day and we're ramping up to plant capacity of 30,000 barrels per day. Tucker will then produce for decades.

At Sunrise, the plan remains to get up to capacity of 60,000 barrels per day and then start the debottlenecking work. In support of this, we're tying in 14 previously drilled well pairs, and furthermore, we're completing plant performance tests this year to confirm the spare capacity at the plant. At 60,000 barrels per day, this project has a field life of more than 100 years, and as you know, we have regulatory approval in place for 200,000 barrels per day and so we're evaluating approaches that will make further expansions profitable in the current environment.

Now, what I want to do, over the next four slides I'm going to take you deeper into each of these areas, starting with Lloydminster. In Lloyd, we have an unmatched land position. We've got 2.2 million net acres. We've developed a deep understanding of the resource through 50-plus years of experience and our geologic models allow us to zero in on reservoirs best suited for our thermal projects. We have nine thermal projects up and running in a very tight geographic area. It's all physically connected to our own infrastructure, including our upgrader and our asphalt plant, right in the heart of our Lloyd-based business, giving us of course a significant competitive advantage.

We have a number of similar thermal projects on deck and the team is of course also continuing to look for additional opportunities, leveraging our land position, our expertise and our ability to pilot and integrate technology into our developments, and we can do so at low risk and with high reward.

Let's look at the economics now of a typical 10,000 barrel per day nameplate Lloyd thermal. As those of you that are following us closely know, we've extracted great capital efficiencies in our projects, and our projects typically come on at higher rates than nameplate capacity. Furthermore, our project build time is very short, about two years from shovel to first oil. These projects are sanctioned at an assumption of about 50% recovery but we've seen up to 70% on some of our earlier thermals. Sustaining capital requirements are in the range of $5 to $7 per barrel. The barrel op costs for newer builds are in the neighbourhood of $8 to $9 per barrel with steam-oil ratios averaging 2.2. Importantly, our Lloyd oil is a better quality than Fort Mac bitumen meaning less heat is required and it commands a higher realized price. This combination of lower cost and higher realized pricing delivers higher netbacks. Remember too that this is just the Upstream economics. It doesn't factor in any of the additional benefits realized further down the Corridor.

We'll now turn to Tucker. At Tucker, we've seen some significant progress over the first couple of years. By applying our thermal expertise, including going after some of the same zones as we do in our Lloyd block, we're on our way to full plant capacity. We expect to reach that 30,000 barrel mark next year. We recently brought a new pad on production, and we've just completed the drilling of another pad with first steam in October and first oil at year end. Tucker is now making a strong contribution. Over the next five years we expect it to deliver more than $1 billion in free cash flow, and as it continues to ramp up, op costs will go lower to less than $10 a barrel.

Now, looking at Sunrise. Here, our number one job, as we've spoken to, is to ramp up to full plant capacity of 60,000 barrels per day in 2018. We're two years into our ramp up, and as of this morning we're around 40,000 barrels per day. That's 725 barrels per day per well pair, approaching our estimated range of 800 to 900 barrels per day from the original 55 well pairs. In fact, to get to 60, we're bringing forward two previously drilled pads. These consist of 14 well pairs, and the capital has been accelerated to tie-in these wells for approximately $50 million net to Husky. Using the existing plant steam capacity, they'll start up and be on production before the end of this year, and this will get us to the mark by the end of 2018. Now, while the projected average peak rate is lower, the expected reserves recovery for individual wells actually remains the same, so this therefore is an acceleration of capital and not additional capital.

We'll take a step back now and look at the profitability improvements in our thermal business. First of all, most of our cost savings—most of the cost savings we have been achieving have been structural. Our new projects have lower construction costs, as well as lower operating costs, F&Ds, and sustaining capital needs. They're also replacing declining higher cost conventional production across the portfolio and it's driving our margins up. Intertwined with the structural changes are further improvements that we secure through the modular design concept. At Lloyd, for example, construction costs are coming down. The later three thermal projects came in at $25,000 per flowing barrel, down from over $30,000 just a couple of years ago. Similarly, operating costs are coming down to sub-$10 per barrel as a result of higher production rates, better steam-oil ratios, and much tighter integration in the new plants. We're also leveraging the high quality service industry and the local workforce in Lloyd. No need to fly in and out, no camps, and our employees go home at night, and we can easily access a highly-skilled workforce, a local workforce, thereby keeping our additional costs down.

At Sunrise, we've seen significant reductions in costs by reducing the footprint of our sustaining pads. We've been able to reduce the cost of the well pads by 40%. This has been done by using inline meters rather than expensive and large group and test separators. We use the pumping capacity of the electrical submersible pumps to pump the fluid all the way to the plant, and therefore eliminating the need for extra transfer pumps on the pads. The use of a custom-built walking rig has also cut down on our drilling time, and furthermore, this rig actually lets us place the wellheads more closely together, which has further reduced the module sizes and our environmental footprint. So the growth of our thermal business, coupled with the structural changes and the other improvements we're making across this business are going to generate approximately $3 billion of free cash flow over the coming five years. We're doing so by replacing legacy production with high-return thermal growth, and these thermals have both long lives and require low sustaining capital.

Now, I've talked a couple of times in this presentation to how technology is helping us advance our thermal business. In fact, it really is interesting to look at how much of Husky's business today is built on recently developed technology, and so I want to talk to this for a little bit. Technology is essential for us to, firstly, drive down cost; secondly, to increase oil recovery; and thirdly, to improve our environmental performance. We're doing so in our thermal program, and we're doing so in our resource play development that Gerald will talk to shortly, and the advances we've made in the Atlantic region and in Asia are often predicated on technology that has only recently been developed.

Specifically in the thermal arena, our industry is still in the early stages of the technology curve, both in terms of sub-surface technology and the types of technology required to drive capital efficiency, so as such, we see a number of technologies that have the potential to make an impact, and we have either incorporated, piloted, or are closely following quite a few innovative techniques. The table here on my right shows a selection of them, and is by no means a comprehensive list. We're focused on those technologies that are at the highest value potential and are technically viable, or stand a reasonable chance of becoming technically viable. Our teams develop our own technology, and we also look to incorporate the advances from the broader industry, and in this area we deem ourselves fast followers when it comes to developments from outside of Husky.

I want to highlight here a couple of areas that we're pursuing in our thermal business. I'll start with our own diluent reduction in the oil sands. Here, we're moving towards piloting our patented technology at our Sunrise operation. We call it Husky Diluent Reduction, or HDR for short. HDR has the potential to significantly increase the quality and the value of the Sunrise bitumen; it will reduce the amount of diluent required for blending, and as such it will increase the effective capacity of our pipelines. A 500 barrel per day pilot has received both federal and provincial funding, and is expected to be up and running in the next couple of years.

In the Lloydminster area, we have a long history—we have a really long history of technological innovation. Historically, and as you know, industry's view of thermal heavy oil development was a large-scale project requiring lots of capital. However, we've developed the technologies to economically tap into smaller pools that are ideal for 5,000, 10,000 barrel per day projects. Having numerous smaller developments has allowed us to try out all sorts of ideas with limited risk. We've adopted many small changes and efficiencies. This is a major step change in how we develop and build such projects, and we've pioneered a number of firsts that have helped us deepen our knowledge of the reservoir, maximize recoveries, and build these smaller copy and paste style facilities that are models of efficiency. Examples of this include extensive integration and heat exchange at the new plants, and even deploying thermal technology in a field where cold production had already taken place.

Today, we have about 80,000 barrels per day of thermal production from nine facilities around Lloyd. Our growing production, coupled with the changing regulatory environment, is increasing our emissions cost, so we are looking to capture the carbon from the thermal plants and to use it to our advantage. In fact, we're piloting a number of CO2 capture technologies at our Pikes Peak South thermal facility, and these have the potential to reduce the cost of carbon capture by half compared to existing technologies. At the same time, we've been developing CO2 injection technology for the past 10 years, so in the field pilot this has actually increased our oil recovery in our CHOPS wells from about 8% to about 20%. We've produced 2.7 million barrels through CO2 injections, and we're currently producing about 2,000 barrels per day of—2,000 barrels of oil per day through this CO2 injection, and I'll note too that the CO2, once injected, stays in the reservoir.

Now, we're still in the early stages, but this is actually a unique opportunity that marries our legacy CHOPS production with our growing Lloyd thermal program, and it can really benefit both, so the big prize here is leveraging our emissions from the steam plants as a CO_2 source to increase the oil recovery from the vast field area currently not justifying thermal application. In the end, this could actually, feasibly, turn Lloyd thermal oil production into a lower carbon source of energy.

To sum up, over the next five years we're anticipating a 50% thermal production growth. The thermal business is expected to generate about $3 billion in free cash flow, and our application of new technologies will continue to unlock value.

Thank you and I'll turn the floor over to Jeff who will take us through the Downstream segment of the Corridor.

JEFFREY RINKER:

Yes. Always great to follow Andrew. Thanks very much Andrew, and good morning. I've just joined Husky recently as the Vice President of Downstream Value Chain, and I'm happy to be participating in my first Investor Day at Husky. Before I get started, I want to thank my boss, Bob Baird, who's in the room. He's the Head of Downstream for Husky, for giving me the chance to present his part of the business today.

I've been working in the downstream part of this industry for most of my career in a lot of different places, so I've had a chance to see a number of different downstream configurations in my career, and the thing that strikes me about the way Husky is configured is the high degree of physical integration between the Upstream business and the Downstream, and also just within the Downstream business itself. You can draw a pretty straight line from where Husky Hydrocarbon starts its life in the oil fields someplace, through the Husky Operated Gathering Systems, through the upgrader, and then down through our outbound logistics, perhaps to one of the refineries in the U.S. for conversion to motor fuels, and then out through the product logistics to our customers in the U.S. Midwest. And one good thing about this kind of physical integration is that it gives you takeaway certainty.

You can be pretty sure of finding an outlet for all the product that you produce, but in addition, or beyond thinking about the Downstream business in this linear sort of way, I see it as a series of linked options along the chain, and I hope that I'll be able to demonstrate to you that there's real value opportunity in this integrated optionality, because that's a competitive advantage, this physical integration of our assets and the optionality that it gives us.

An objective of Husky is to match the upstream heavy oil production growth with our heavy oil processing capability in the Downstream, and by doing so, we reduce our exposure to the Canadian heavy oil differential, and instead we expose the Company to international product markets, so gasoline, diesel, asphalt, and so on. So, you can think of us that way, as a Canadian heavy crude producer, without all the exposure to the Canadian heavy oil quality differential and the location differential. We currently have a total throughput capacity in the Downstream of about 350,000 barrels a day, and of that, 160,000 barrels is heavy oil processing, and that's set to grow.

All right, but before we talk about the growth and the optionality, let's take a quick tour of the Downstream part of the Integrated Corridor. You'll see on the left of the slide is, in Canada we have the Lloydminster Complex, and this is—processes 110,000 barrels a day of heavy crude into light synthetic crude, diesel fuel, and asphalt. The Complex is distinctive for its low operating costs and advantaged feedstock, and especially advantaged feedstock for making asphalt. The physical integration with the upstream is very high. Virtually all of the barrels coming into Lloydminster are Husky barrels.

In the middle of the slide is our U.S. business. In the U.S., we operate 160,000 barrels a day Lima, Ohio refinery, and that's predominantly a light oil refinery, but we have recently upgraded it to process up to 10,000 barrels a day of heavy oil, and it's set to expand its heavy processing capabilities even further. We also own 50% of the 140,000 barrels per day Toledo, Ohio refinery. That's a heavy oil refinery and it's recently been modified to run more of the high-TAN crudes like the ones we produce at Sunrise. We market our share of products from both of the refineries in the U.S. Midwest, and also, beginning this year we're now marketing all of the secondary products produced at Toledo on behalf of the joint venture, and on the far right of the slide, the U.S. and Canada are linked together by our pipeline and storage business, and that includes substantial storage at key locations; storage at Lloydminster, at Hardisty, at Patoka, Illinois, and also a 75,000 barrel a day firm capacity commitment on the existing Keystone Pipeline.

All right, with a tour of Downstream complete, let's talk about the growth and optionality story. We have two new major investments in the works for adding value to our crude—our heavy crude stream. At Lima, the crude oil flexibility project is going to add another 30,000 barrels a day of heavy crude processing capacity to the refinery, taking us up to a total of 40,000 barrels a day, and we're looking to double our asphalt production capacity at Lloydminster. These investments, together, will increase our heavy oil processing capacity to approximately 220,000 barrels a day. That's a 35% increase, just keeping pace with the forecasted growth from the upstream, so Andrew, we're on your—we're chasing you, and the upstream is going to keep growing, so one of the things that we have to do in the Downstream, of course, is to continually evaluate sensible projects, or sensible ideas for expanding our heavy oil processing capacity.

Let's look at the two investments in a little closer detail. At Lima, we're already constructing the crude oil flexibility project. It'll be fully on-stream by the end of next year, and at this point we have about $215 million left to spend on that project. We're expecting good returns from the project, and with significant heavy crude growth expected in Canada, we expect the economics of converting heavy crude to motor fuels in the U.S. Midwest to continue to be pretty attractive. And at Lloydminster complex we're looking to expand the heavy crude processing capacity there from 110,000 barrels a day to 140,000 barrels a day by doubling the asphalt production capacity. The engineering on the project is well underway and we'll be taking a final investment decision next year, but the metrics look pretty compelling.

The asphalt margins have been strong for a lot of years, generally in the order of $20 per barrel, or so, at Lloydminster. We'll realize capital cost efficiencies by building the new asphalt unit within the available land in the Lloydminster Complex, and we're no strangers to the asphalt business. Already Husky is producing about 4% of all of the asphalt manufactured in North America, and we're the biggest producer in Western Canada, and we see that market conditions are favourable. After a long period of restricted infrastructure spending, we're beginning to see demand recovery, and we're confident that we can place the increased production in the North American market.

Finally, our asphalt has a natural cost advantage in that the Lloydminster feedstock is of such high quality that it requires less additives to convert it into performance grade asphalt. So pending all the Board and regulatory approvals, we would look to begin construction on the expansion next year, and be ramped up to full capacity by 2021, and when you consider both of these projects, the one at Lima and the one at Lloydminster, it's important to consider that neither project requires us to access additional pipeline takeaway capacity. But it's not all just about taking away the heavy oil and boiling it.

The investments we've been making in Downstream processing capacity are contributing to improved margins within the Downstream itself. The average feedstock costs have already decreased by about $3 a barrel at Toledo due to the high-TAN project, and as a result of the planned investments, the crude oil flexibility at Lima and the asphalt expansion at Lloydminster, the percentage of our entire refining complex capable of processing heavy crude oil is going to increase from 45% to 60%. And this increase translates into about a $2 US per barrel lower feedstock cost across the entire Downstream business. And we're very clear on Downstream's role. We take away the heavy crude exposure and we return cash to the business.

We're expecting the Downstream business to kick out about—just about $3 billion in free cash flow over the coming years, and you can see it's quite a stable and consistent cash flow. There's three elements that will enable us to deliver this consistent performance. The first one, just like any downstream business, it's all about stable and reliable operations, so we'll continue our focus on operational efficiencies and high utilization rates. The second important element is just continued investment in heavy crude processing capabilities, like I've already discussed, and both of these elements have their focus mostly inside the facility fence line. But there's a third important element in capturing—and that's capturing available margin that's outside the fence line, up and down the integrated value chain.

I've spent about half of my career working in Europe where, especially in recent years, refinery margins have been much more under pressure than they have been in the U.S. Midwest, for example. And what I've seen is that downstream businesses that survive there are the ones that have been able to capture this additional margin available outside the facility fence line, and I believe that Husky's integrated business model positions us really well to do the same. Here's what I mean when I talk about the physical integration creating optionality. This is a really simplified diagram of Husky's integrated Downstream business, but even in the simplified diagram, you can see there's a lot of nodes where optionality exists. So, for example, I've got the option of taking the equity crude from my business into my own refinery, or into my own processing unit, where I can sell it locally, or I can use my transportation infrastructure to transport it to a remote customer—a remote market.

From the processing point of view, I have the optionality of what kind of crudes and feedstocks to bring into which of my processing units, and on the product side, I have optionality around where I bring the products from my processing units. Do I sell it locally? Do I use my infrastructure to transport it to attractive markets? And so I'd like to give just one practical example of how this flexibility works. So, for example, the conventional way that we feed Lima with sweet crude is by bringing it synthetic crude from the Lloydminster upgrader down the Keystone Pipeline, and this is kind of a typical way of running the Lima refinery. But there might be times when there's a more attractive opportunity to take our synthetic crude directly to customers in the local market, or to take it on other pipeline access to eastern Canada, for example. And when we do that, we have to supply Lima—or we would supply Lima with different sources of sweet crudes, like from the U.S. domestic crude, the Bakken, or crude from the Permian, and if we do that, this then creates optionality on the Keystone Pipeline.

When we're not using it to transport synthetic crude down to Lima, we can use it to transport, for example, a heavy crude from Hardisty down to our customers in Cushing or Patoka, and this kind of optionality, it only becomes apparent when you think about and optimize the entire system, rather than optimizing individual nodes along the system along the way. And this isn't a theoretical example. We've implemented exactly this light crude for heavy crude flex on Keystone in our May operating plan and it's delivering us between $1 million and $2 million additional net margin in the month of May alone. And it's worth pointing out that in this kind of a optimization, this might not be the optimal way of running Lima refinery in isolation, or it might not be the optimal way of running the upgrader, but the overall system is at the economic optimum, and next month the whole thing's going to change again. This sort of crude oil logistics optimization is just one example of the sort of opportunities that are available when we manage the Downstream in an integrated way, capturing margins outside the facility fence line.

Another example is that physical integration gives you the ability to create your own feedstocks that are optimal for your processing facilities, so at Lloydminster, for example, the crude oil we feed Lloydminster is optimized or customized for Lloydminster. It's not the commercially available Lloydminster crude oil, and we're making some further modifications during the current turnaround to give us additional feed flexibility. There are also flexibilities in the product side of the refinery. Our U.S. refineries are located between the three major pricing hubs of Chicago, U.S. Gulf Coast, and New York Harbour, and we're developing logistics capability to shift a bit sales or sales volumes between these price points as the markets change. For example, just this year we've invested in the capacity to deliver products to markets on the Great Lakes.

Other opportunities include exchanges in intermediate streams between the refineries, like gasoline blending components to de-constrain the refineries, and especially in moving beyond our current practice of selling almost everything at prompt pricing, and to capture opportunities that are available along the forward curve. So we're already doing this in the natural gas storage market, but our asset portfolio is really well suited to expand this practice to include location differentials across the pipelines and upgrading spreads, among other things, and this is by no means an exhaustive list.

Based on my past experience, I think there's an opportunity for Husky to further capture up to $0.50 to $1 a barrel of incremental margin all along our highly Integrated Corridor of assets, and that adds up to as much as $100 million a year, none of which, by the way, is in the 2021 forecast that Rob showed you earlier. For the past few years we've been running a project called the HydroCarbon Value Chain to put in place all of the integrated optimization tools and processes and organization that we'll need to lift this value, and that's, in fact, one reason I think why Bob invited me to join Husky. It'll take us a couple of more years to capture it fully, but the prize is significant and it's real.

To finish up, the Downstream section of the Integrated Corridor helps us maximize our margins through tight physical integration, which in fact creates optionality; and by optimizing across the entire integrated chain, which lets us capture margins that exist outside the fence line; by investment in heavy oil processing capacity that will let us keep pace with upstream growth. But also, in its own right, deliver margins within the Downstream business; and all the while keeping our eye firmly on cost control and uptime and reliability.

I thank you for your attention and now I'm going to turn the floor over to Gerald to talk about our growing gas resource business in Western Canada. Thank you.

GERALD ALEXANDER:

Thanks, Jeff. I'm excited to be here and to be given the opportunity to complete the repositioning of the Western Canada business, advance the gas resource development program, and build a new opportunity in the Montney. I've been working with Husky Energy for over 20 years, and originally, I worked in the Ansell field. Technology has certainly changed since that time, so now let's take a look at the rejuvenated asset base.

Our resource business is focused on being more nimble and developing larger, more material plays. We've just came through the repositioning of this portfolio, and the process is now mostly complete. We're currently producing about 75,000 BOE a day, and are in the position to see growth through our five-year plan and into the next decade. We have a large drilling inventory, which will be targeting high rate, liquid rich plays, including our new opportunity in the Montney, which I'll discuss in a few slides from now. The investment opportunities that we have in this business are economic at today's prices, and can compete for capital. Furthermore, a key strategic role of this business is to supply an internal hedge to the gas consumption of our refineries and our thermal plants.

Now let's look at how the transformation has improved the outlook for our business. We've reduced the number of well bores on the books by about 10,000. Our asset retirement provisions have come down by about 30%, and we're able to drive down our operating costs by 25%, while average overall production per well has almost doubled, and we continue to focus on improving our efficiencies. The graph on the right illustrates how repositioning of the portfolio has significantly reduced the sustaining capital requirements. As you can see, from before 2015 we were spending about $1 billion annually to hold production flat. Looking ahead, we anticipate sustaining capital to average about $200 million per year.

On the right is a—is the production we expect to see over the five-year plan. Today we are forecasting measured growth in our resource plays. Clearly, this is an area of the portfolio where we have the most capital flexibility. The short-term nature allows for a quick adjustment depending on market conditions. Similar to the transformation of our thermal business, this one is also structural. Including the dispositions announced in the first quarter of this year, we've sold about 37,000 BOE a day that had an average operating cost of $20 a barrel in 2015. Trimming these higher-cost assets and bringing on new, lower-cost production has led to the improvement of our operating costs of about $4 per BOE, as it currently sits in the $16 per BOE range. With the continued investments that we are making in our lower-cost, higher yielding, liquid rich gas plays, we are forecasting the improvements in our capital efficiencies and in our operating costs. This will lead to increased net backs and further enhance our cash flow.

We've also been working to improve our performance in our legacy assets. Rainbow Lake has been a solid performer for many decades, generating steady free cash flow and funds from operations, with relatively steady light oil production. We've made the required investments to allow us to produce back the previously injected NGLs in natural gas. With that spending now behind us, we are in the position to harvest the resources that remain in the reservoir. It's expected to have a 15+ years of flat production at the 20,000 BOE per day level. Rainbow now can be considered, or be thought of, as an annuity. Over the next 15 years we expect it to deliver more than $570 million in free cash flow.

Now let's have a look at the set of investment opportunities ahead of us. We'll be focusing on two main areas; the Wilrich in the Ansell and Kakwa, and further up the trend, the Montney formation in Karr and Wembley. With these two areas there is a large inventory of well locations that clear our hurdle rate of 10% IRR at $2.50 AECO by some margin. In our Wilrich play, we have material land positions in both Ansell and Kakwa, with 160 and 30 sections of land respectively. We have a measured drilling program designed over the next five years that will see the pace of drilling matched with the cash flow generated from the area. The high-rate wells we are currently targeting will double the production from 20,000 barrels per day today, up to 40,000 in 2021. With a combined 450 potential drilling opportunities on our lands, we have a long runway ahead of us.

Looking now at Ansell, we've been working this area for several years and we've made some noticeable efficiency gains. Since 2014, our drilling costs are down about 50% and our drilling times about 60%. Historically, we have achieved an effective well lateral placement of about 70% in the targeted zone. This is now in the 90-plus% range. Our hydraulic fracturing design now incorporates more intensive number of stages, which has increased the productivity along the well bore. As such, we have been achieving higher test rates and on-stream rates, each year since 2014. If you look at the well type curve on the right, you can see the improved flow rates year-after-year. The most recent well data from the 2017 program shows even more improvements. We have the well results testing even higher shown by the blue stars on the graphic, and in fact, not shown on this chart, we have a well that's currently testing at 14 million cubic feet per day that we're really excited about. Along with the higher production, we've also been increasing our expected EOR from the wells. 2016 is up 25% over 2014, and we are anticipating that the results from this year's wells will lead to even further increases for 2017.

Switching gears for a moment, we've been quietly accumulating land and solidifying our position in the heart of the Montney fairway. We now own more than 150 sections in two key areas. The Wembley area is prospective for liquids rich gas as you can see by the map. Husky lands are in yellow, and we're in pretty good company, being adjacent to and on trend with Pipestone. At Karr we have about 50 sections of land offsetting the Gold Creek field, and we're focusing on oil there. It's still early days in both of these areas, but we have been encouraged by our initial results. We're looking at further delineating our position this year with a total of four wells planned.

To sum up, the Western Canada repositioning is essentially complete. We are now realizing the benefits of a more focused, gas weighted portfolio that is able to generate more competitive returns. We have a very good land position, with over 500 drilling opportunities in the Wilrich and the Montney, and this will allow us to develop—allow us to focus on our development efficiencies and increase our well performance and our ultimate recoveries.

Now we'll step away from the Integrated Corridor, and I'll ask Bob Hinkel and Malcolm Maclean to come up to go through the Offshore business. Thank you.

ROBERT HINKEL:

Hi. I'm Bob Hinkel. I'm the COO for Asia Pacific region, and thanks Gerald. You heard a lot about our Offshore business at Asia Pac and the Atlantic, and we have a lot of competitive advantages in these areas. Combined, the economics are extremely attractive, with plenty of upside over the plan period and beyond. Both regions have near-term visible growth with high net backs. Projects in each of Asia and the Atlantic regions are leveraging off existing infrastructure for greater cost efficiencies, and now we can sell our oil and gas to both regional and global customers. In fact, you may have heard, Husky has recently sold light sweet crude from the Atlantic fields into Mainland China, and in terms of free cash flow generation, the upside is quite significant. Asia Pac will deliver free cash flow in the coming 10 years, and in the Atlantic, we are currently cash flow positive and looking to further growth once West White Rose is up and running in 2022.

So we have a long history in this region. In fact, we've been in China for over 15 years now, working with our partner. We've used this time to build our local knowledge, our relationships, and our deepwater expertise. A good example is our Wenchang Project, which has generated more than $2 billion in cash to Husky to date, and with the commissioning of our first gas field offshore Indonesia underway, and the advancement of additional fields in the Madura Strait, Husky has really hit its stride in Asia.

Our projects and opportunities are spread over the short, medium, and long term, and they have some similar characteristics. Looking forward, we have high-return priorities that can share existing infrastructure, and because of that, there's relatively little incremental capital cost. This segment of our business is going to deliver more than $4 billion in free cash flow over the plan period from the Asia Pac region. We benefit from both fixed price contracts to building escalators, and also from the size and growth in the gas demand in Asia.

By the end of this year, there'll be more than 400 million cubic feet per day under fixed price gas contracts on a gross basis. That's 190 million cubic feet per day net to Husky, in addition to 12,000 barrels per day of NGLs. This reflects production from the Liwan Gas Project in offshore China, and the BD project in the Madura Strait. Over the next few years, our series of gas fields will come online in Indonesia, and we will also tie in the third Liwan field at Liuhua 29-1. Further out, you can see our anticipated production profile for the region, which reflects the 50% growth rate over the coming five years and beyond.

Our growing presence in Asia is anchored by our successful Liwan Gas Project, which was the first deepwater gas project in China, and it came in on time and on budget. We have two natural gas fields online in this project, Liwan 3-1 and Liuhua 34-2, which are both located in the Pearl River Mouth Basin about 300 kilometres southeast of Hong Kong. We hold a 49% working interest in the PSC, and we operate the deepwater wells and the infrastructure, while CNOOC manages the shallow water platform and the onshore gas plant. The deepwater includes the wells, the trees, the subsea pipelines, and the manifolds, which are produced into two 22-inch pipelines running about 79 kilometres to a shallow water central platform. From there, the gas flows another 260 kilometres to an onshore gas plant that separates the gas liquids into multiple product streams, which increases the value of the stream. Last year, our share of production of the two fields was 113 million cubic feet per day average of natural gas, and about 6,000 barrels per day of liquids. Under the take-or-pay contracts, we realized prices of about CA$13 per MCF. Operating costs work out to about $1 per MCF, or $6 per BOE. I'll just note, also, that we've increased the reserves in this block, which have more than replaced production to date. We've had a 23% increase in reserves in this field.

The third field in the Liwan trio is Liuhua 29-1. We're continuing our negotiations, and subject to the signing of a sales gas agreement, we anticipate a sanction decision in the second half of this year. The project will be tied directly into our existing subsea infrastructure, which provides for excellent cost efficiencies. The economics are very attractive with potential annual free cash flow of more than $150 million. In addition to our 49% share of the gas, we expect to recover approximately $340 million of exploration costs on a preferred basis during the first 18 months of production.

Now turning to our growth plans offshore and in Asia, the liquids rich BD fields are the first in a series of planned projects in the Madura Strait. We are currently in the process of commissioning the FPSO for this project, and the ownership of the block is held by three companies, Husky, CNOOC, and a local partner. CNOOC is the contracted operator, and Husky holds a 40% interest in the block. On deck, we have three fields in the Madura Strait that will be brought online in the 2018/2019 timeframe. The shallow water MDA-MBH fields will be developed in tandem, and a third field at MDK will be tied in at the same time. They will all share infrastructure, including a floating production unit, and the processed gas will be tied directly into the existing East Java subsea pipeline system.

Farther out, we have a plan of development in place for the MAC field, and the feed activities are underway for that field. We also have two additional discoveries, MAX and MBF that we are evaluating for potential development. Once again, the economics here are quite good. We anticipate the Madura developments will give us free cash flow in the $700 million range over the planned period, with additional upside over the full 10-year outlook.

Let's take a closer look at our newest development which is the BD project. BD gas is produced through a shallow water wellhead platform into a dedicated FPSO, which is pictured here. There it is processed and piped to shore through a dedicated subsea pipeline and the gas flows directly to an onshore metering station in East Java, the liquids are processed and offloaded via the FPSO and sold into the local markets. The gas is sold into long-term, set price contacts, around $7 per MMBtu, with built-in escalation factors also. We have a net production target of 40 million cubic feet per day of fixed gas price for Husky with escalators, and 2,400 barrels a day of liquids. I'll add a couple of other quick items. These are fixed gas price contracts in U.S.

dollars with escalation factors, and we've taken advantage of low-cost, long-term leases for equipment like the FPSO. As a result, the full cycle of IRRs in this project are in excess of 16%.

Beyond our current projects in Liwan and Indonesia, we have a range of medium-term exploration delineation projects in the region. These are an exciting part of our portfolio, and it really shows the continued growth of Husky's business in Asia. A few years ago, we signed a PSE for Block 1533, which was offshore China, and it's highly prospective for light oil. The block lies in shallow water at Pearl River Mouth Basin with the same type of geology as our Wenchang field has, and just recently we reached agreement for an additional block, 1625 in the same area. We're planning to drill two exploration wells each in these blocks starting early next year. With the combined operation, it will increase cost efficiency. These blocks have a number of benefits. They're both oil prone and they're in shallow water, and their FPSO is already existing in the area and working, so we just need to add a shallow water platform and drill the wells for a very quick development plan, and they're right next to markets that are requiring the oil right now.

In addition to these shallow water plays, we also have one major impact play in a very key area. We've been exploring offshore Taiwan now over the past three years. We've identified a number of significant structures on our 7,700 square kilometre block. There are reservoir outcrops on Taiwan Island, and there's also an existing gas discovery just to the north of our block, so we are currently shooting a major 3D seismic survey in the block, and this will likely be the largest 3D seismic survey shot in Asia this year. Following that, we'll be determining our next steps, including a potential drilling timeframe for the block.

To sum it up, our fixed price contracts and projects in Asia Pac are an important and growing component of our Offshore business. They offer a deep inventory of capital efficient growth opportunities, with compelling rates of return and material cash flow to the Company. There are additional opportunities throughout the region as we continue to leverage our expertise and our established relationships. We will continue to grow this business at low capital cost, and continue to turn out free cash flow over the coming years.

Thank you very much, and I'll turn it over now to Malcolm Maclean who will discuss our plans in the other region of the Offshore business, the Atlantic.

MALCOLM MACLEAN:

Thanks Bob. Like Asia Pacific, our Atlantic business has delivered some of the best returns in Husky's portfolio. We have a long history off the east coast of Canada with a proven track record of operating in harsh weather conditions. We began production from White Rose back in November, 2005. Since then, we have produced over 275 million barrels of oil, almost 200 million barrels net to Husky. To date, Husky has spent $5.5 billion developing White Rose, which has generated an EBITDA of $12.5 billion. That's a $7 billion net contribution to our business over these years. We are now on the eve of our next project at West White Rose. Its development will result in significant growth for Husky in the Atlantic.

Our White Rose area development strategy has been about stepping out and stepping down. We continue to step out from the main White Rose field with satellite tiebacks from North Amethyst and the South White Rose extension. More recently, we started to step down by targeting the deeper Hibernia formation. In the near term, we plan to bring on two wells—two infill wells per year, a pace that will help offset natural declines. Our infill wells are targeting arctic oil in unswept areas. They generate high rates of return, as they benefit from our mature water floods that make additional water injection wells unnecessary. They also maximize use of our existing infrastructure.

We have two new wells on the books for this year. Our North Amethyst infill well came onstream in February and is now producing around 8,000 barrels per day net to Husky. A South White Rose extension development well is scheduled for first oil in the fourth quarter, and at its peak we expect it to produce about 4,500 barrels per day net. South White Rose development wells and infill wells at White Rose and North Amethyst are bridging us to the next chapter of our Atlantic story. We announced yesterday that we are moving ahead with the West White Rose development. This is a major project that represents our renewal of the Atlantic region. It's of a scale approaching the original White Rose development. As you can see from the chart to the right, it will more than double our Atlantic production when it starts up in 2022 and peaks in 2025 at 52,500 barrels per day net to Husky. This is a major development, so I'll dig into it a bit deeper. I'll take you through some of the things we have done to make West White Rose a robust investment, even in the current price environment.

We've been busy over the past couple of years doing the optimization work needed to make a good project even better. This has meant looking at a number of ways to improve capital efficiency and resource capture, including fine-tuning the facilities and subsurface designs. While requiring a larger upfront capital expenditure, the wellhead platform will lower drilling costs, and has the potential to recover over twice as much oil as a subsea development. As a result, capital efficiency has been improved by more than 30%. Platform construction will commence in the fourth quarter of this year, and will be installed and connected to the SeaRose FPSO in the summer of 2021.

Following first oil in 2022, we'll ramp up to a gross peak production of approximately 75,000 barrels per day in 2025. This is 40% higher than our initial estimate. The project is unique as it takes—it will take advantage of our existing infrastructure, as all oil processing and storage will be handled by SeaRose. With a tieback of this new production to SeaRose, overall per barrel operating costs for all White Rose production will actually come down as the project ramps up. This is because the cost of operating SeaRose is predominantly fixed. The incremental operating cost of adding production from the wellhead platform will average about $3 a barrel in the first 10 years. In addition, the project will also increase earnings right away, as its capital expenditures will result in lower royalty rates for our existing production.

Looking further out, we have lots of opportunities. In line with our stepping out strategy, we recently announced an oil discovery at Northwest White Rose, an exploration well about 11 kilometres northwest of SeaRose delineated at light oil column of more than 100 metres, which we're currently evaluating. Any development could leverage our existing subsea infrastructure and the West White Rose wellhead platform. In addition, last November we acquired two exploration licenses in the White Rose area. This includes a block adjacent to our new Northwest White Rose discovery, and another immediately to the north of White Rose, both reinforcing our stepping out strategy.

In the Flemish Pass, last year's appraisal program in the Bay du Nord area led to new discoveries at Bay de Verde and Baccalieu. We're continuing to assess their commercial potential. We have a 35% working interest in the Bay du Nord, Bay de Verde, Baccalieu, Harpoon, and Mizzen discoveries. Together with our partner, we will be drilling a couple of additional exploration wells in the Flemish Pass this year. In fact, we started drilling the first one on the 15th of May.

All in all, we have a very robust Offshore business, both in the Atlantic and Asia Pacific. Let me summarize. Combined, the economics are attractive, with plenty of upside over the planned period and beyond. Both areas have high net back production and strong growth potential. In terms of free cash flow, the upside is significant. In Asia, we'll be generating free cash flow of $4.2 billion over the coming five years. In the Atlantic, the 52,500 barrels per day of West White Rose production will kick off a whole new era of growth.

Thank you for your attention. I'll now turn the floor back to Rob and we'll take your questions before we wrap up for lunch. Thank you.

ROB PEABODY:

Okay. We can take any questions from the floor. I realize most of the time most of the analysts would prefer to keep their best questions to themselves, so to the extent you want to do that, we will be around for lunch. Go ahead.

NEIL MEHTA:

Thanks, Rob. Neil Mehta here from Goldman Sachs. I just wanted to kick off on the dividend, which you guys referred to at the beginning, but would love for you to flesh that out. How are you thinking about the timing? A $50 to $60 oil price and the free cash flow that you talked about is certainly supportive of the case for resuming the dividend, but want to hear your perspective on that, and I have a follow-up.

ROB PEABODY:

Super. I'm going to hand the specifics of the question over to Jon, I think. One thing I will say is, clearly we've said the Board revisits this every quarter, and the next time they're really going to revisit it is the next quarter in—is 2Q, and for those of you who remember circumstances around the first quarter, you'll realize the world, in the particular week we were looking at, looked like it might be tipping into an abyss again, so that may have had something to do with some of their thinking at the time, but Jon can just review, sort of what they've been looking at.

JON MCKENZIE:

Sure. Is this on?

ROB PEABODY:

Yes.

JON MCKENZIE:

Good. Okay, so thanks for the question. For those of you who aren't familiar with our dividend history, we cut our dividend in Q3 2015, and this question has arisen pretty consistently since about Q4 2015, so I've got a very practiced answer for this, and something that's very consistent. But as Rob mentioned, the dividend is truly a Board decision, and the conditions present for reinstituting the dividend we've been pretty clear about from day one. What I would say, prior to getting into those three pre-conditions is the dividend at the time that we cut it was a $1.2 billion dividend. I think what we've shown today is a $1.2 billion dividend in today's pricing environment isn't sustainable. But to the point that you're making, Neil, we think a more modest dividend is sustainable with the cash flow and earnings that we're seeing, so three pre-conditions that we've talked about pretty consistently, they need to be met for us to institute the dividend. All but one have really been met, and that third pre-condition is in around seeing a sustainability in the oil markets in terms of the supply/demand balance and seeing some sort of direction in the oil markets. And I think as a management team and as a board, we're getting closer and closer to getting comfortable with that third pre-condition, and again, that's something that the Board will look at in the July board meeting and we'll make a decision at that time.

NEIL MEHTA:

All right, Jon. The follow-up is, you guys laid out a $50 case going to $60, but you've also laid out a $50 flat case.

JON MCKENZIE:

Yes.

NEIL MEHTA:

The forward curve of that $50 flat case, and so if we were to adopt that as the scenario, how does that change the way you manage the business? The growth projects that you talked about, are those still the projects that you would sanction? Does capital get flexed, or is this kind of a fixed capital program? Then just talk about what the cash flow and growth rate looks like more at the $50 case.

JON MCKENZIE:

Yes, and what we're trying to portray in that $50 flat case, is at $50 we have free cash flow to fund the capital program and the dividend, so it wasn't one or the other. We recognize that to our investors that the dividend is important, and we don't want to invest in the capital program to the detriment of the dividend. Both are important. It's not one or the other. It's both, and what we were trying, and what I think we're portraying to you today, is we have both liquidity and financial strength to manage both the capital program and the dividend at a $50 WTI price. Both are extremely important to us.

The capital program takes us to an entirely different place in terms of our cost structure and the quality of assets that are producing, and we certainly recognize on the other side of that that we need to return some of this free cash flow to our investors. So at the time that we institute the dividend, as I mentioned, it'll be more modest than what we had before. But the dividend, as well as the capital program, are entirely sustainable in that sort of $50 world, and we believe even at $35, if we were to cycle down to that pricing for a period of time, we have the flexibility to maintain the Company and that paradigm of capital and dividend for a short period of time.

ROB PEABODY:
Super. Other questions? One over here.

PHIL GRESH:
Hey. Good morning. Phil Gresh, JP Morgan. I guess I'm going to have to follow up on Neil's question a little bit here, just on the $50 case. You talked about $1.3 billion of cumulative free cash flow in that scenario. It sounds like sticking with the capital program, as is, is the target. I wanted to clarify, does that cumulative cash flow include the asphalt project? It would be another $700 million to $900 million in CapEx?

ROB PEABODY:
No, no. That includes the asphalt project.

PHIL GRESH:
It does?

ROB PEABODY:
Yes.

PHIL GRESH:

Okay. Okay. Got it, and then my second question is just kind of thinking bigger picture, the growth capital spend that you're laying out is about $7 billion over the five-year period, and I guess I'm wondering how you weigh investing for production growth over the long term versus the potential for buying back shares? I know it's not something that you've typically done in the past, but it's nearly half of your market cap that you're spending on growth, so I'm just wondering how you weigh that decision of growth versus the value of your own stock price.

ROB PEABODY:

Yes. Well, first of all, I would say, and I hope this has come across in the presentation a bit, is that growth capital is for both production growth and margin growth, and as Jon kind of pointed out earlier, that's why we see the capital program as so intimately connected to our program to reduce our breakevens over time as well. So it is part of the grand plan to spend that capital in order to keep bringing down the breakevens of the Company. So, that capital is quite dear to us and we don't see flexing that capital program around tremendously.

When it comes to dividend buybacks, I think what you'll see is—and again, I can't speak on behalf of the Board, but if you look at traditionally what the Board did, where there was the excess free cash flow above that sort of program, we've returned it directly to the shareholder through special dividends. And that, where the balance sheet got kind of too strong, or too under-levered, as opposed to doing share buybacks, largely because we're aware of the fact that we have a major shareholder, and if we keep eating away at the float in the Company, it kind of reduces liquidity in the shares, ultimately, and most of our shareholders would prefer to have more and not less liquidity.

NIMA BILLOU:

Hi. Nima Billou, Veritas Energy. Just a quick question on the White West Rose project. What's the project life as it stands now with the initial investment? Is it 20 years, 25 years?

ROB PEABODY:

Well, first of all, the SeaRose, which is an important component of this project, currently we anticipate its life is slightly beyond 2030. We may be able to extend it a little bit beyond that as well. It's actually in phenomenally good shape. We did have the opportunity to put it into dry dock there. In terms of the project life, I'll give that to Malcolm, just because he's the expert.

MALCOLM MACLEAN:

Yes. The design life for the wellhead platform is 25 years, but again, the concrete gravity structure, really by virtue of its nature, would last much longer than that, but typically the design life for offshore platforms is around 25 years.

NIMA BILLOU:

Okay, appreciate the colour on that, and I know you're using existing infrastructure, but is it really $3 total production and operating costs for the first 10 years?

ROB PEABODY:

To be very clear, what we said there, it's the incremental operating costs for West White Rose are $3 a barrel, and that's because the existing field is still cash positive through to 2030, the existing production, so you're really looking at what are the incremental operating costs you're putting in place to run all this new production through it?

Interestingly enough, in offshore platforms—this is something that a lot of people don't realize, and in fact most oil operations, is when production goes down, it's going down because the oil cut is going down. The total fluids are still the same, so everything's working just as hard as it ever did, so when West White Rose comes on, we would then take the very, very high water cut wells out of the SeaRose and then put in oil wells that are just cutting pure oil, which actually is easier on the SeaRose in terms of running. So that's how the substitution works over time.

NIMA BILLOU:

Thank you.

MALE SPEAKER:

Thanks. My question is for Bob. Could you just return back to 29-1 in terms of how the recovery on the exploration expenditures will work, and I think you mentioned that that's like $340 million. I just want to get the numbers right.

ROBERT HINKEL:

Yes. The way it was originally set up when we did the original supplemental development agreement for the whole block, we apportioned the exploration costs to different fields, so that was done back in 2009, so the amount of exploration costs apportioned to this field was about $330 million or so, so we recovered that. Now, what will happen is in the first instance you get your exploration costs back is the first cut out of the production, so very early on in the production life, you get about a 15% to 19% additional bump up in your revenues to recover those costs, and that comes out of your partner share. The next thing is the development costs. The development costs are proportionally covered. Since we share the development costs equally, though, they come back equally to each side, but there are some tax advantages to that too.

MALE SPEAKER:

On the $340 million, then, that'll all accrue to Husky.

ROBERT HINKEL:

That money accrues all to Husky. That was strictly Husky—because the way it works out, you take the exploration—we take these blocks on—it's the same with the two new blocks, you take the exploration risk on yourself entirely when you first start out, and then once the discovery's made and the development goes on, you are allowed to recover that exploration cost. And CNOOC backs in for 50%, but since they never put up any exploration costs, it's all your money coming back.

MALE SPEAKER:

Thank you.

RYAN SAVAGE:

Ryan Savage at Investors Group. I'm looking at your resource play and seeing that you have 450 potential net drilling opportunities. Does this encompass all of your Wilrich stuff, and do you have current estimates for your Montney in the Karr and Wembley areas?

ROB PEABODY:

Rob, do you want to take that?

ROB SYMONDS:

Ryan, the 450 are Wilrich locations in Kakwa and Ansell, so they're all there and we can move them forward. In terms of the Montney acreage, so we have 150 sections. We're early on in the appraisal. If you were to use typical Montney per section numbers you'd get obviously a similar number of drilling locations in the Montney as well, but given we've only just started drilling, while I like the neighbourhoods, it's premature to be confident that we have all of those locations ready to go. The other thing to remember, the Montney, those of you that were looking at the slides, because of infrastructure constraints in that area, we're not anticipating significant production can come on for three years, that being the lead time with infrastructure.

ROB PEABODY:

Okay. We either have some hungry people out there or people with really good questions that they're not going to share with the room, which is fine.

So first, thanks for those questions. Really appreciate them. I hope that through today's presentation and discussion you've—you have a clear picture of Husky's direction, our plans, and our targets. We have two well positioned businesses, the Integrated Corridor and the Offshore. In each, we plan to invest in a series of projects that have strong returns. This will further reduce our already industry leading low break-evens. Two-thirds of this investment is weighted towards short and medium term cycle investments. The plan allows us to grow while maintaining the strength of our balance sheet, one of the strongest in the industry, and generate increasing amounts of cash flow which can be returned to shareholders.

We have positioned Husky to be resilient while still preserving the upside associated with commodity cycles, which enhances our risk adjusted returns.

Thanks again for spending the morning with us and we expect to see as many of you as we can over lunch. Thanks.