Legislative Assembly of Alberta

The 28th Legislature
First Session

Standing Committee on Alberta's Economic Future

Bitumen Royalty in Kind Program
Stakeholder Presentation

Wednesday, November 28, 2012
6:20 p.m.

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Standing Committee on Alberta's Economic Future

Participant

6:20 p.m. Wednesday, November 28, 2012

[Mr. Amery in the chair]

The Chair: Well, good evening ladies and gentlemen, and thank you all for being here this evening. Thanks to all the guests and the staff who are joining us tonight. I would like to call this meeting to order, and I'd like to ask all those members around the table to introduce themselves. Also, members who are sitting in as substitutes for committee members should indicate this in their introduction. I will start. I'm Moe Amery, MLA for Calgary-East and chair of this committee.

Mr. Bikman: I'm Gary Bikman, MLA for Cardston-Taber-Warner, and I am deputy chair.

Mr. Quadri: Sohail Quadri, MLA, Edmonton-Mill Woods.

Mr. Rogers: George Rogers, Leduc-Beaumont.

Mr. McDonald: Everett McDonald, Grande Prairie-Smoky.

Ms Fenske: Jacquie Fenske, Fort Saskatchewan-Vegreville.

Ms Jansen: Sandra Jansen, Calgary-North West.

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Mr. Bhardwaj: Naresh Bhardwaj, Edmonton-Ellerslie.

Mr. Dorward: David Dorward, MLA, Edmonton-Gold Bar.

Mrs. Towle: Kerry Towle, MLA, Innisfail-Sylvan Lake.

Ms Smith: Danielle Smith, Highwood.

Dr. Sherman: Raj Sherman, Edmonton-Meadowlark.

Mr. Strankman: Rick Strankman, Drumheller-Stettler.

Mr. Quest: Dave Quest, Strathcona-Sherwood Park.

Mr. Sandhu: Peter Sandhu, Edmonton-Manning.

Dr. Massolin: Good evening. Philip Massolin, manager, research services.

Mrs. Sawchuk: Karen Sawchuk, committee clerk.

The Chair: Thank you and welcome.

Just a few housekeeping items to address before we turn to the business at hand. Please note that the microphone consoles are operated by the *Hansard* staff, and please keep cellphones, iPhones, BlackBerrys off the table as they may interfere with the audio feed. The audio of committee proceedings is streamed live on the Internet and recorded by *Hansard*.

Ladies and gentlemen, the first item that we have on the agenda is the approval of the agenda.

Mr. Rogers: So moved, Mr. Chairman.

The Chair: Moved by Mr. Rogers. All in favour? Opposed? Carried.

The second item that we have is the approval of the meeting minutes of Alberta's Economic Future, the meeting that was held on November 21, 2012. Moved by Mr. Quadri. All in favour? Opposed? Carried. Thank you very, very much.

The fourth item that we have on the agenda is the stakeholder presentation, and we have a presenter with us here tonight, Mr. Mike Ekelund, assistant deputy minister, strategic initiatives. Also, we're joined by Mr. Cooper Matheson, special assistant to the hon. Mr. Hughes, Minister of Energy, and Mr. David Gowland, chief of staff to the hon. Mr. Hughes.

Mr. Ekelund and Mr. Matheson and Mr. Gowland, on behalf of the committee thank you very much to the Alberta Energy representatives for accepting our invitation to appear and provide us with an overview of the BRIK program from the perspective of the government department responsible for its administration.

As a starting point for our review – we're on a very tight schedule tonight – I will remind everyone of the process. Our presenters will have 20 minutes – and we will be using the timer; I think Karen will be using the timer here to keep everyone on track – followed by questions from the committee. With that, I will turn it over to our presenter, Mr. Ekelund.

Department of Energy

Mr. Ekelund: Okay. Well, thank you very much for inviting me here this evening. I'm going to go through some basic stuff, background around royalties, which I will go through fairly quickly, the methods of collection that we use currently, the policy direction and objectives that we have been given as a department, actions to date, how we're implementing, and some of the current uses and future suggestions that we have heard with respect to bitumen royalty in kind.

To start off, the basics around royalties. Alberta generally owns the mineral resources underneath the land in the province. In the chart here it shows that about 81 per cent of mineral rights are held by the Crown. There are a number of different organizations who have historically or otherwise obtained mineral rights. I'm not going through the details in them, but there are other freehold or other owners of mineral rights in the province.

Petroleum rights are allocated for production and for exploration. We call them land sales. It's not actually a sale of the ownership of the rights but a sale of a mineral lease or a mineral licence which allows production. One of the key elements of any mineral lease is the ability for the owner to retain a share of the production as part of the mineral lease.

The Mines and Minerals Act lays out in legislation what the terms are for royalty in the province. The first key piece is under section 34(3), that royalty reserved to the Crown in right of Alberta are deliverable in kind. That's essentially how royalties are in mineral leases. It is a share of the production. Unless we otherwise change that in the regulations, they are delivered in kind. The other piece here is that they are to be delivered at essentially the place of first measurement.

The right to receive delivery in kind is not only in the Mines and Minerals Act with respect to leases. It is also in Crown agreements with respect to the original oil sands projects. That would cover Suncor, Syncrude, Cold Lake, other projects. Under the oil sands royalty regulations we have changed that from being a delivery in kind to a cash delivery basis. I'll go through some of the details about how that's done.

There are two main approaches in Alberta to how royalties are collected. The first one is the one that we use in natural gas. Once the royalty volume is separated from the land at a well, there is a share that belongs to the Crown, and that is carried by the producer. The producer has custody of the Crown's royalty share until you get to the point of first measurement. In respect of gas plants what we have is a deemed sale of the Crown's royalty share once the gas has reached the custody transfer meter at the tail end of the gas plant, so the natural gas has been processed so that it is saleable. It is clean, the various contaminants removed, and you get good measurement there. It's sold at a natural gas reference price to the producer. After that all of the volumes then belong to the producer, who carries them to market and sells.

The other approach is the one that's used in conventional oil. Again, once the oil is severed from the land, then there is a share that belongs to the Crown and a share that belongs to the producer. It is carried by the producer to an oil battery, which is generally the first location of measurement. It is carried from the battery – if it's a heavy oil, then condensate is included – to a feeder pipeline which connects to the main export pipelines. Once it reaches the feeder pipeline, the Petroleum Marketing Commission, which is a corporate entity set up in 1973 to handle all of the Crown lands oil – and after deregulation of oil pricing it handled the Crown's royalty share – takes custody at that point and then sells it in the market.

In both of these cases the costs for getting from the wellhead to the point where custody is delivered either to the producer for gas or to the Petroleum Marketing Commission for oil are paid by the Crown, in the case of gas through an allowance of costs and in the case of the Petroleum Marketing Commission through direct payment for trucking and piping and so on.

Once the Petroleum Marketing Commission has the oil in its custody, it can do two things. For about 10 per cent of the oil it sells it directly into the marketplace to refineries at various locations. The other 90 per cent is handed over to a Crown agent, which is currently Nexen, and they deliver it along with their own barrels. That is a model we went to in the mid-1990s.

Those are the two main approaches: conventional oil, delivery in kind; natural gas, deemed sale. The oil sands are deemed sale to producers, similar to natural gas, essentially at the edge of a ringed fence around the oil sands project, and are sold at a unit price. It's not the quite the same as the natural gas reference price because it is more dependent upon where the project is and the quality of the bitumen and so on.

The direction we received under the new royalty framework in 2007 was to consider options such as taking bitumen in kind as a way of supporting more value-added in the province, upgrading and refining in particular. In 2008 and 2009 in the mandate letter provided by the Premier of the time there was direction to the Minister of Energy to implement bitumen royalty in kind as part of the strategies to increase upgrading and refining capacity in the province. The provincial energy strategy also spoke to value-added for bitumen although it did not speak specifically to bitumen royalty in kind as a tool.

6:30

At the same time, we conducted a broad public consultation process on oil sands, covered a number of areas about how to develop oil sands, one area of which was to add value within the province, and talked about using the Crown royalty share of bitumen as a tool to help diversify markets and strategically use it to support diversifying the economy.

The mandate letter in 2010 that was given to Minister Liepert reiterated the 2008 mandate letter, essentially implementation of strategies to increase upgrading and refining, including implementation of bitumen royalty in kind.

The historical policy objectives that were set out. These are on a number of different documents that can be found on the Department of Energy website. The first one was fostering value-added oil sands development, and that was, essentially, around value-added upgrading, refining. There have been some changes in the wording of that over time.

The second one: enhancing the bitumen market in Alberta. It's a market with a number of non arm's-length transactions, a market with a number of different qualities of the product being sold. Having a better window into the bitumen market, we have some opportunities to potentially understand it better and potentially enhance that market.

Also, to share in the differential gains/risks between synthetic crude oil and bitumen: that was one of the early statements. It was focused primarily on using the bitumen as a way of fostering value-added synthetic crude oil production; in essence, upgrading. It's also been stated in terms of a broader look at upgrading, refining, and petrochemicals, understanding that bitumen cannot only be made into synthetic crude oil. It can also be refined into higher value products and possibly into petrochemicals as well.

Then the more general statement: maximizing the value of resources, recognizing that it could go even beyond just using for upgrading or refining.

Just a current picture of oil value-added in Alberta. We have 94 oil sands projects, approximately 2 million barrels per day of production. It's expected that that could reach 3.4 million barrels per day. Alberta is already a significant area of value-added. There are five bitumen upgraders in the province with 1.3 million barrels a day of capacity. As well, we do have four oil refineries with 450,000 barrels per day of capacity. We also have five major petrochemical facilities. These are generally using ethane as a feedstock extracted from natural gas, but there has been work going on to use off-gases from oil sands projects, from upgraders, and from refineries. So that's a possible area of oil value-added as well.

The actions that we've taken with respect to the objectives that were given. We first put out an expression of interest in 2008. That was to determine whether there was interest in use of the royalty share of bitumen and what that could be used for and possibly how to best use that. We received a number of different proposals. Some were projects around processing bitumen into synthetic crude oil, into refined petroleum products, others were to support or accelerate export pipelines by committing to long-term capacity arrangements that would be backed with Crown royalty barrels, and others to assist in marketing and administration of the Crown's royalty share.

Based on the interest that was shown, we were able to refine a request for proposals. The direction given was to narrow that down to the value-added piece around upgrading and refining. The request for proposals is on our website as well. There's quite a bit of detail around it, but it was essentially requesting proposals to build a value-added large-scale facility in Alberta, including feedstock providers. It gave two options, either sale to the facility or a processing arrangement. It contained a number of the key terms of what could be in a processing arrangement, and then there was a list of criteria that were used to evaluate the proposals that were received.

From the evaluation of the proposals North West Upgrading was selected to go into further negotiation of the final terms within the terms of the request for proposals. That included a processing agreement and a marketing agreement. The processing agreement was with respect to their first phase and included 37,500 barrels a day of bitumen plus diluent that would be processed into diesel fuel, diluent, naphtha, vacuum gas oil, and so on and, also, a marketing arrangement around a second 37,500 barrels a day, which would be used for the second phase but would be marketed until such time as a decision was made either to go ahead with the second phase or not go ahead or, I think, for a term of five years.

A total commitment of 75,000 barrels per day of delivered bitumen.

What we're currently working on is the implementation for delivery. In the implementation the first things we looked at were: what were the appropriate processes to be able to deliver the bitumen to achieve the goals that were set out? There was industry consultation with the stakeholders who would be most affected by what those processes were. The policy direction had been given previously. The question was: exactly where are the barrels transferred, under what terms, which tank, which pipe, what gets paid, where, and how? We worked with a number of oil sands producers through the Canadian Association of Petroleum Producers on the details of those processes as well as doing our own in-house work on what kind of systems would be required, how we'd deal with a number of issues such as non-open access pipelines and so on.

The goals. We wanted a system that would meet Alberta's policy objectives as laid out, the ability to avoid adverse impacts on production or on markets – we wanted to make sure that we didn't cause issues in terms of agreements that had been put in place and so on – administrative efficiency for government and industry, fairness. There are large projects and small projects. If you are taking bitumen from smaller projects, that's more administrative work, but if you only take it from one set and not from the other, then you've got some questions around fairness. We wanted to ensure that it was fair among the projects and neutral to the oil sands royalty system. This is a change in the collection of the Crown's royalty share, not a change in what the Crown's royalty share is. It's how we collect it and use it as opposed to a change in the fundamental structures of the royalty system.

Coming out of our consultation with industry, we developed a simplified model, which is a number of willing producers who would supply bitumen blend in Edmonton or if necessary in Hardisty. Under contract part of it would be bitumen royalty in kind, for which they would receive credits for having paid their royalty, and there would be a cash difference if they're delivering more than what their royalty amounts are. Similarly, they could aggregate that between a number of different companies to be able to provide it primarily in terms of royalty credit but still a cash difference if there are others.

What this allowed was a market-based approach. We'd certainly understand that the quality would be the same every month as opposed to changing depending on which projects are producing how much, the volume would be certain, we'd know the producers, and the producers were willing to discuss providing that supply. A number of them feel that the Crown would be a very good buyer in the marketplace. The others would remain on the cash royalty system. That would limit the number of impacts on agreements in place. That would limit the number of details that we'd have to have in terms of where volumes are delivered and who would deliver on behalf of who else and a number of other issues. It affects fewer producers and was viewed as fair by the producing industry.

Future additional needs, if there are any that the government directs us to collect, would be met by additional producers over time. Again, this was seen as fair for expansions as well. It was recognized that most volumes that are currently under contract are for a year, so these volumes would be available if necessary. We did look at putting a regulatory process to collect all of the royalty bitumen in the province in case this model did not work out at some time in the future. However, in the consultation it was determined that we wouldn't need to have a detailed regulation at this time. The process appears to be workable, simple, supportable, and the ability to put in a regulatory approach is still there if necessary at some point in the future.

6:40

Just a graphic on the simplified model. A smaller number of designated producers – the rest stay on a cash basis – would provide the bitumen. They'd basically carry the bitumen from their projects through their own tankage through the feeder pipelines to Edmonton and into tankage on the pipeline system in Edmonton. That is where the custody transfer would take place and the provision of royalty recognition through credits and cash for the differences. That would pass custody to the Petroleum Marketing Commission. At that point, the Petroleum Marketing Commission would keep ownership all the way through but transfer the volumes physically over to North West Upgrading, who would process the 37,500 barrels in their refinery and sell the other 37,500 barrels until such time as there is a decision made on phase 2. That simplifies the process to collecting at the tanks in Edmonton and then transferring over to North West, who would be then carrying the volumes with the Petroleum Marketing Commission on behalf of the government of Alberta, maintaining the ownership throughout the process from there.

Under the initial model the amount of bitumen royalty volumes in kind was a critical factor. We wanted to make sure we could assure supply for any amount that was used and deal with monthly variability and so only dedicate a certain portion of the potential volumes available. With the simplified model what's more critical is that there are sufficient volumes in the marketplace for those producers to provide, and the actual physical availability becomes secondary. It's still important because the only regulatory approach that the government could put in place if it had to at some time in the future would be for the volumes it actually owns. It would be limited by that.

Just to give an idea in terms of bitumen supply. This is from the ERCB forecast from earlier this year, and it continues to show significant increases in the amount of bitumen and in the amount of nonupgraded bitumen being removed from the province.

Our historical look at this. This is on the department website. It went out with the working papers on bitumen royalty in kind. The chart on the right is the one that was most critical when we were looking at a full delivery of bitumen model and ensuring that there were significantly more physical volumes available than there were commitments. You see the commitment was based on about half of the potential barrels available to handle any variability in the volumes.

However, looking at the more simplified model, this is the work that we did on total volumes actually physically available, netting out places where the bitumen couldn't physically get to either Edmonton or Hardisty, and there are significant volumes there, so significantly more volumes available in the marketplace than have been committed to this date.

The current use is that we've got the Petroleum Marketing Commission volumes dedicated to the Sturgeon refinery and for the marketing that are dedicated potentially to phase 2. There have been suggestions about additional upgrading or refining as a possible use of bitumen royalty in kind. As well, there has been public commentary about potentially using bitumen royalty in kind to support capacity commitments on strategic pipelines. That was one of the suggestions that came through the request for expressions of interest. APMC has historically done this, but this was back in the 1990s. It supported line 9 to Montreal, I think, from 1992 through the mid-1990s. It had a 15-year commitment on the Express pipeline. It also supported Trans Mountain on the west coast initiative, which ended in 2000. Again, it was moving

Crown royalty barrels of conventional oil on ways that maintained those pipelines going certain directions or being able to move volumes when there were restrictions on other ones.

Just the last point. There was a question that came up at the committee about economics. These are case-by-case questions. There is no bitumen royalty in kind general economics. If you're looking at upgrading, it's a question about whether the costs of the facility are greater than the bitumen and synthetic crude oil differentials. Similarly with refining: are the refined product differences compared to the feedstock costs greater than the costs? Similarly with a pipeline: are the differences between where you deliver and where you pick up the bitumen greater than the tolls? Similarly, if you've got something on rail, is the price at what you deliver versus where you pick it up greater than what you pay in terms of the railcars to get there?

Just in summary, the concept follows historical practices with conventional oil although that was a number of years ago. Action to date has focused on fostering the value-added piece, essentially the one refinery. The implementation is being moved ahead with a simplified model. I believe initial deliveries would likely be in 2015 for a 2016 start-up to give some time to get the processes in place. Other uses have been suggested publicly. The economics are unique to each business situation and would require economic and feasibility analysis.

Thank you.

The Chair: Thank you. Thank you very, very much, Mr. Ekelund. I know this is a very complicated issue. I was told that you have a wealth of knowledge, expertise, and information, and you have certainly demonstrated that tonight. Thank you very, very much.

Now we will open the floor for questioning. Let me outline the questioning process here. We will start with five minutes for the Wildrose caucus, five minutes for the PC caucus, five minutes for the Liberal caucus, and five minutes for the NDP caucus.

Ms Smith: Thank you, Mr. Chair. Thank you, Mr. Ekelund, for the fantastic presentation. I have a number of questions. I'll try to keep them brief. First of all, when you were going through talking about a number of expressions of interest in the proposals, do you recall how many individual companies or consortia put forward expressions of interest initially?

Mr. Ekelund: I could give you a general number, but it could well be wrong. It is on our website. I believe it was 29, but it might have been 25, 26, something in that range.

Ms Smith: Okay. Fantastic.

I was also curious. Now that you've signed the arrangement with North West Upgrading, is there anything that you would change when you're negotiating a future contract with a future company on these lines? Have you learned anything from this initial project, or is it too early to say? If there is another company that comes forward wanting to do this, are there things that you'd do differently?

Mr. Ekelund: I've negotiated a number of commercial arrangements. I'd always like to be able to negotiate a better deal. We've learned a number of things from this.

The Chair: Sorry, Mr. Ekelund. Can you speak closer to the mike so that we can hear you?

Mr. Ekelund: Okay.

We've learned some things from this, but I would suggest that they are at the margins. There could be better ways to achieve the things that we did achieve in a shorter version and maybe a less complex approach.

Ms Smith: Anything specific that you could point to?

Mr. Ekelund: No.

Ms Smith: With the North West deal is there any particular dollar value that crude has to be selling at for us to hit a sweet spot of it being profitable for everyone? I think that there has been a little lack of clarity about some of the terms and whether or not the taxpayer might be on the hook for a subsidy or support if the dollar value gets too low. We've now seen the dollar prices come off quite a bit from their highs. Is there any dollar figure where you start getting nervous that perhaps there's going to need to be some taxpayer support?

Mr. Ekelund: Well, there is no subsidy. It is clear in the agreements, which are on our website and publicly available, that the Crown is taking the differential price risk. There is a toll arrangement in place on a cost-of-service basis, which is similar in concept to natural gas processing, some pipeline arrangements. The Crown owns the bitumen when it comes in. The Crown owns its share of the products coming out. The question is whether or not the price difference between diesel fuel and diluent within Alberta, the western Canadian market, and potentially what might be exported into the northwest U.S. is higher than the bitumen used as feedstock and whether that is more than what those costs would be in terms of the costs of building the facility and operating the facility.

When we did the estimate in the technical backgrounder that I presented to the press at the signing of the agreement, we estimated that there would be a discounted cash-flow return over the life of the project somewhere in the area of $200 million to $700 million at a reasonable industry discount rate. So we expect it to be profitable.

6:50

Ms Smith: Would we be in the money today, with the prices where they're at, if this was in operation?

Mr. Ekelund: The chair of North West has publicly stated that it would have made about $500 million this year. That's because of the wide difference between product prices, which are essentially tied to Brent product pricing and the low price that we're getting for west Texas intermediate, which affects western Canadian select. We've got a double discount going on, Brent to WTI and also WTI to WCS. It would have been, in Ian MacGregor's words, very profitable this year.

We look more at what the long-term outcomes would be, and we think that in the long term, with increases and decreases over time, it would be profitable in that range.

Ms Smith: Fantastic.

I have a few more questions. How much time do I have left, Mr. Chair?

The Chair: About a minute and a half.

Ms Smith: A minute and a half. Okay. I'll try to go quickly.

First of all, you mentioned in the first slide that there's a certain portion of mineral royalties that are owned by First Nations. Do you know what that percentage was? I didn't see it on your graph.

Mr. Ekelund: No. I'm sorry. I don't have the percentages with me.

Ms Smith: No problem.

The issue of the First Nations refinery, Teedrum: my understanding is that they had 13 conditions that they needed to meet to move to the next level. Did they meet those 13 conditions?

Mr. Ekelund: What we had was direction to work with Teedrum to develop a conditional term sheet. It was recognized by both the Crown and Teedrum that their proposal was very challenging. We tried to develop a conditional term sheet that laid out a number of conditions that they would have to meet such that if any of those conditions were not met, then the Crown would be able to not go ahead with the arrangement.

Further, the direction was given that this would go into the political process for consideration if they demonstrated the support of the First Nations. I am not certain that the full support of First Nations for the project was met. That is something we were working through with them. This had not gone into the political process, but with the review of this by the government, they determined that they would not continue on with that. That was based on the risk as represented by those large number of conditions about where they would get money, getting partners, a number of other things.

Ms Smith: Thank you.

The Chair: Thank you, Ms Smith.

Any other questions?

Ms Smith: Do I get another chance to come back to him after? I just have one last question, so I was just wondering if I had a chance to come back.

The Chair: Yes, you will.

Any other questions?

Okay, Ms Smith. You can ask your question now.

Ms Smith: Thank you. I'm just curious. I noted that you said that the Crown agent is currently Nexen. Of course, Nexen is in the process of being taken over by the China National Offshore Oil company. Does that leave you with any concern that the Chinese state government would be our official agent handling our product? Is there some process in place, should that takeover go ahead, for us to choose another agent?

Mr. Ekelund: There are probably a number of answers to that. The first one is that the agreement with Nexen is terminating, and there should be a request for proposals out, probably on our system tomorrow. These agreements go for a certain time and then they have termination terms. It was decided some time ago, before the takeover discussion took place or before there was any public announcement of that at least, as far as I know, that they were not going to continue at this point.

The second one is that regardless of who invests in a company as a shareholder, we would fully expect them to follow all of the laws, the regulations, and the policies of the province of Alberta.

Ms Smith: I don't want to monopolize the time. I'm quite happy with that.

The Chair: Thank you.

Mr. Rogers.

Mr. Rogers: Thank you, Mr. Chairman, and thank you, Mr. Ekelund, for your presentation. My question is more of a general nature. We hear a lot of discussion, suggestions, and, of course, a strong desire that we refine more product here in this province. Our natural tendency has been to pipe away a lot of raw materials, and the two large pipeline projects that are on the drawing board right now would do just that. We would be selling raw product, be it south to the U.S. or west to likely Asia and other places offshore. I think it's safe to say that most people would agree that if the opportunities presented themselves here, the desire to upgrade more product here in this province will provide a lot of benefits, obviously, value-added jobs, investment like the North West Upgrading project that's on the drawing board right now.

My question would be: based on the available supply of BRIK bitumen in terms of our access as a government to more bitumen, do you anticipate that if another proposal like a North West or whoever – for that matter if Rogers Incorporated said, you know, that we would like to build an upgrader to whatever level, whether it's going all the way to full refining or just to the synthetic stage and possibly diesel – do we have the ability as a province under the current BRIK environment and production levels as we know them today and as we anticipate them to be to potentially see another refinery that's supported by BRIK?

Mr. Ekelund: There would not be a physical limitation for an additional upgrader or refinery or other use similar in size to the commitment that has been made under the physical delivery model and less limitation with the simplified model. The challenge will not be primarily around physical supply of bitumen. It is around what is the economic case. As I said, every situation would need to be fully evaluated. An evaluation was done at what the market opportunities were for diesel, which we tend to be short of, and diluent, which is needed for the additional increases in bitumen being produced.

Once phase 1 and phase 2 of North West have been built, the question is: how much additional market would there be on the export basis in the Pacific Northwest? For other regions you'd have to do a full business case to understand what those opportunities would be. I can't really say that there's a limit on the physical side, but clearly there would have to be a clear business case for it to be economic.

Mr. Rogers: I realize that, sir, and I thank you for that. Obviously, we know that these facilities are rather large, very capital intensive. So, yes, I do understand the whole aspect of the business case. I guess my question was, again – and I suppose you answered that at the start – in terms of the supply. It would seem to me by your answer that based on what we anticipated – essentially, the royalties that we expect coming forward means that there would be enough supply. If someone made that case, we would have a supply of bitumen as the government out of BRIK that we could channel to a proponent.

The Chair: Can you answer briefly, please?

Mr. Ekelund: Yes. On the physical side, as you see on the chart, there's an increase over time.

Mr. Rogers: Thank you.

Dr. Sherman: Thank you for your presentation. Can you go back to that one slide that sort of showed how much upgraded and unupgraded bitumen we were going to have?

Mr. Ekelund: Yes. That's the forecast from the ERCB ST-98. I believe that came out in June of this year.

Dr. Sherman: So the forecast by 2021 is that 70 per cent is unupgraded. Is that correct?

Mr. Ekelund: I don't have the percentages, but that seems about right, yes. It's in the high 60s, somewhere in there.

Dr. Sherman: What is the differential today between the international price and what we're currently getting for our western Canada select? What's the average differential price?

Mr. Ekelund: I'm sorry. I didn't bring that with me. I usually get a printout each day.

An Hon. Member: I think it's $29.

Mr. Ekelund: I think the $29 might have been WTI or Brent to WTI. In the high 20s, 30 in total is probably correct. I'm sorry. I don't have the information, but it is very high now in comparison to where it's been in the past few years.

7:00

Dr. Sherman: I did a little bit of math here. For every $10 differential from a million barrels a day we would get $3.65 billion a year. That's a lot of money.

Mr. Ekelund: Sorry. You mean in royalties?

Dr. Sherman: From what we're getting now from western Canadian select for the North Sea Brent, the differential, if we were to upgrade and refine everything here and get it to the international marketplace. For every $10 differential that's $3.65 billion per million barrels a year. Would it not make sense for us to insist, for those who want to pipe our product to the west coast out of this country or the east coast out of the country, that it be upgraded and refined, if not in Alberta then this country, before it leaves our borders? Would it not make economic sense?

Mr. Ekelund: Not necessarily. As I said previously, you have to do the business case for each situation. The question is whether or not the price that you would receive in the marketplace for the products that would be developed would cover the costs of building the facilities. From an economic perspective we are probably best served by a portfolio of a certain amount of diluted bitumen being sold into markets to maintain the markets there, and they can be premium at some times; synthetic crude oil – there are some challenges it's facing around light crude oil production in the United States, but there are times when it can be a good market – as well as refined products.

We could not, for example, turn all of the bitumen into diesel in Alberta and have that as an economic business case. It's a question of finding the best potential outcomes of how much diesel, diluent, jet fuel, and so on and where you would sell them and developing a business case for each situation, for each refinery, each upgrader, each pipeline opportunity.

Dr. Sherman: In principle should we aspire towards upgrading refining as much as we can in this country before it leaves our coastal borders at least?

Mr. Ekelund: In the provincial energy strategy there is an aspirational goal that was set out by the Hydrocarbon Upgrading Task Force. That was a number of organizations, companies, government departments, municipalities, and so on who said: we should set a stretch goal, an aspirational goal, something for the province to aspire to, which is where the 66 per cent upgraded or refined came from. It's not a target but an aspirational goal to consider. The economics are what makes economic sense to build another refinery, another upgrader, or to otherwise use the Crown's resources.

Dr. Sherman: Have you done an economic analysis of the jobs and value-added jobs and the spinoff to society other than just the cost of an upgrader, an economic analysis of what the benefits would be, the downstream benefits?

Mr. Ekelund: We have for the refinery that we did select out of the RFP process. Again, those numbers are public. They are on our website, and we've published those fairly broadly. We have not looked at the entire suite of turning all of the bitumen into some sort of product. Again, what we've tended to look at primarily is whether there's an economic business case for an upgrader or refinery. There are, then, jobs and spinoff benefits that come out of that, but the direction we've been given is to primarily make sure that the thing makes economic sense, makes money.

The Chair: Thank you.

Thank you, Dr. Sherman.

We'll take two more questions.

Mr. Bhardwaj: Thank you very much, Mr. Ekelund. I'm going to go back to Mr. Rogers' question because I just want a bit more clarity on that. Keeping Teedrum aside, there are a number of other Indian companies such as EIL and ONGC, who have most recently set up an office in Calgary. Oil India is very much interested in investing in the oil sands. Is there sufficient supply for bitumen if they were to come here and build an upgrader? I was there in mid-October at the Petrotech conference. There were a number of companies represented from around the globe. They want to come here. That's my question to you.

Mr. Ekelund: I'll reiterate my responses a bit. Looking at the chart of bitumen supply forecast from the ERCB, there's a substantial amount of nonupgraded bitumen expected to be produced in Alberta, going from 2 million barrels a day of total bitumen production to 3.4 million approximately. There's lots of potential supply.

The challenge for any company coming into Alberta or any company existing in Alberta is whether or not the long-term price differential that they would get between the products that they would produce and the feedstock would cover the costs of building an upgrader or refinery. For someone like EIL that would be a question of doing their analysis, looking at where they could potentially either sell within western Canada or export products and then what the costs would be of the facilities to do that. There could well be an economic business case on that, but it would have to be looked at on that basis. It's not a physical supply of feedstock limitation.

Mr. Bhardwaj: Thank you.

The Chair: Thank you, Mr. Bhardwaj.

Mrs. Towle: I want to go back to the discussion you had on Teedrum. You mentioned a couple of things in there, and I'm not so sure that we clarified. Being new to this group, I would appreciate the clarification. One of them you mentioned when you were asked if they met the 13 conditions, and you talked about whether they kind of met one of them, but then you went on to talk about how they were in a political field. I'm just wondering if you could clarify that.

Mr. Ekelund: Did I say "political field?"

Mrs. Towle: You didn't clarify whether they met the 13 conditions. Also, you talked about how it became a political decision, and you weren't sure where that was. Then they couldn't get financing from other First Nations people, buy-ins. I'm just wondering if you could clarify that.

Mr. Ekelund: Not financing. Okay. To be clear on it, they did not meet any of the conditions in the conditional agreement because the conditional agreement was about future conditions. The conditional agreement you can find on the Internet, I think, quite easily. It included things, if I remember correctly, such as obtaining financing from the federal government for a certain portion. They had to go out and find a feedstock partner similar to CNRL's role in the Sturgeon refinery. I can't remember; there were a number, something like, I think as you said, 13 conditions.

They weren't conditions that could be met now. They were conditions that they would have to meet over time for the government to enter into an agreement with them. If any one of those conditions was not met, then the government would not have entered into a contract with them. What they had been presented with was that that was going to go into the government process for consideration, and it had not gone into the process for consideration. The decision of the government at the end of the day was that even making a commitment to an agreement full of conditions which may or may not be met at some point in the future was still too much risk for the government. That was the decision.

The Chair: Thank you, Mrs. Towle.

Ms Jansen: Thank you, Mr. Ekelund. A great presentation. We certainly heard the simplistic but charming upgrade-everything-here argument. I'm just wondering if you can tell me what that picture might look like. If you built all the facilities here to do the upgrading in Alberta, how much would that cost and what kind of picture are we looking at? How long would it take to pay for some kind of project or projects that massive in scale?

Mr. Ekelund: I can't do the math that quickly in my head. I'm sorry.

Ms Jansen: It's a lot, isn't it?

Mr. Ekelund: It would require a number of significantly large projects to do that, and essentially it would have to be tied to export markets for jet fuel, diesel, and so on. There would not be that market locally.

Ms Jansen: So if you are in a situation where you have all of that refined product in Alberta, what potentially could be the issues coming out of that?

7:10

Mr. Ekelund: Well, generally, what would happen is that – and, again, this is very hypothetical – if you were to upgrade or refine all of the products in Alberta, then you've got to find someplace to sell them. The more products you sell, the more products you produce within Alberta. If you do not have marketplaces to sell them, then the lower the price gets. It's what's happening with the bitumen today. The bitumen is basically backed up in the mid-west. There's not enough pipeline capacity to go from the Chicago mid-west region to the Gulf coast. That's why there's a difference between Brent and WTI. We're essentially flooding that central mid-west market, and that's where the value for pipelines to the west coast, pipelines to the east, pipelines to the south come from.

You would do the same thing if you tried to turn it all into diesel. Again, the economics would generally point toward some portfolio of different sales of bitumen, synthetic crude, various products. Some of that could be for export offshore. Some of it could be for supplying refineries in central and eastern Canada as well as offshore there. Those are our possibilities. But if you try to sell all of one suite of products, it becomes problematic. The lower the price, then the harder the economics are to cover the costs.

The Chair: Thank you, Ms Jansen, and thank you, Mr. Ekelund.

Dr. Sherman, I know you have a question. Can you read it into the record, please, and we will make sure that you will get a written response for that? Make it fast. We have two more items to deal with.

Dr. Sherman: I recognize that we don't have the water, and it's not practical to refine everything here. Would the economics be there if we were actually to refine this in other parts of the country, in the have-not parts of the country, and have other Canadians have the opportunity to create jobs, pay taxes? Have you done that kind of analysis? If we transported it to eastern Canada for them to refine, create jobs – right now, at this point in time, we're paying a lot in transfer payments to the other provinces. If their economies were to do better as a result of working with our bitumen: have you done an analysis in that respect, how much it would save Alberta in transfer payments and how it would affect their economies?

The Chair: Thank you, Dr. Sherman. We will make sure that you'll get a written response for that for your answer. Thank you.

For anybody else who has any questions, we would . . . Please.

Ms Smith: Just wondering if the government is in any current discussions with any other company or consortium of companies for additional upgrading projects similar to what has been already decided with North West.

The Chair: Thank you very much.

One more thing. The clerk just informed me that we got this around 4:30, 4:35 this afternoon, so she was not able to provide a hard copy for each and every one of you, but it is posted on the committee internal website.

The other item that we have is other business. The date of next meeting. We were supposed to meet next Wednesday with North West Upgrading as a presenter. They informed us that they will not be able to make it, but they will be able to attend on the 11th or the 12th of December, either from 10 a.m. to 11 a.m. or 1 p.m. to 2 p.m.

An Hon. Member: Can you poll us instead of trying to do it now?

The Chair: Okay. We will do that. The meeting next Wednesday will be cancelled.

Any other business? A motion to adjourn?

Thank you very much.

[The committee adjourned at 7:14 p.m.]

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