THE ALBERTA ENERGY REGULATOR

IN THE MATTER OF
Regulatory Appeal 1927181
to the Alberta Energy Regulator

AER PROCEEDING
VOLUME 2
VIA REMOTE VIDEO

October 14, 2020

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Proceedings taken Via Remote Video

October 14, 2020 Morning Session

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C. McKinnon	Hearing Commissioner
B. Zaitlin	Hearing Commissioner
S. Poitras	AER Counsel
A. Hall	AER Counsel
D. Campbell	AER Staff
E. McKellar	AER Staff
S. Botterill	AER Staff
E. Galloway	AER Staff
T. Turner	AER Staff
A. Shukalkina	AER Staff
L. Berg	For ISH Energy Ltd.
S. Hryciw	
J. Jamieson	For Canadian Natural Resources Limited
A. Vidal, CSR(A)	Official Court Reporter
S. Howden, CSR(A)	Official Court Reporter

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1 (PROCEEDINGS COMMENCED AT 9:14 AM)
2 Discussion
3 THE CHAIR: So nice to see you all back
4 here again today. I do have a couple of things on my
5 housekeeping list before we start in on the questioning
6 this morning.
7 The first is yesterday afternoon Canadian Natural
8 was using a couple of aids to questioning. We had
9 marked the first one for reference but not the second
10 and third.
11 So, Ms. Jamieson, did you want to mark the second
12 and third as well, or ...
13 MS. JAMIESON: Yes, please, if we could do
14 that.
15 So, Ms. Turner, we could mark all three of those
16 in succession. That will be helpful.
17 MS. TURNER: So identification only?
18 THE CHAIR: Yes. That's right.
19 MS. TURNER: So I'm not to give them
20 exhibit numbers; isn't that correct, Madam Chair?
21 THE CHAIR: Yeah. They're being marked
22 for identification, the way you did -- my understanding
23 was yesterday afternoon you had marked Canadian
24 Natural's Aid to Questioning Number 1 for
25 identification, so we should mark 2 and 3 as well.
26 MS. TURNER: All right.

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1 THE CHAIR: And just -- if they've got
2 numbers that are sequential, that will be helpful.
3 MS. TURNER: Okay. So it would be 86.0 --
4 sorry -- 87.01 for Aid to Question Number 1; for
5 Number -- Aid to Question Number 2, it would be 87.02,
6 and then the third would be 87.03.
7 MS. JAMIESON: Thank you.
8 THE CHAIR: Thank you.
9 EXHIBIT 87.01 FOR IDENTIFICATION PURPOSE
10 ONLY - Aid to Questioning Number 1 (Jamieson)
11 Stratigraphic interpretation
12 EXHIBIT 87.02 FOR IDENTIFICATION PURPOSE
13 ONLY - Aid to Questioning Number 2 (Jamieson)
14 2014 Jablonski paper
15 EXHIBIT 87.03 FOR IDENTIFICATION PURPOSE
16 ONLY - Aid to Questioning Number 2 (Jamieson)
17 KN startups above 6,500 kPa annotated
18 THE CHAIR: So that was housekeeping
19 matter number 1. Housekeep matter number 2 is -- this
20 might be something a little bit different than what was
21 discussed in the practice session last week, and that's
22 just that when we do break, whether it's for the
23 midmorning break, lunch break, whatever the case may
24 be, and we set a time to come back, just like in an
25 in-person hearing, we ask that the parties keep track
26 of the time, and we enter the virtual hearing room, you

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1 know, a couple minutes before our start time so that we
2 are ready to go. And I think our Zoom host has been
3 sending messages. They're not always obvious. I was
4 noting yesterday we were getting them in our breakout
5 room two different days -- two different ways. It
6 seemed there was a broadcast message that would appear
7 as a green banner across the top and then a different
8 kind of message that sometimes appears down in the
9 lower right-hand corner. I haven't seen enough to get
10 a pattern yet, but just -- somebody needs -- if
11 you're -- the best thing to do is for all of us to be
12 mindful of the time and just rejoin without trying to
13 figure out where the prompts are going to come from.
14 Are there any other housekeeping matters,
15 Ms. Turner?
16 MS. TURNER: I'm just wanting to let you
17 know, if you're not actively speaking, you can turn off
18 your video. So that would be anybody except for
19 counsel and ISH witnesses and the Panel.
20 THE CHAIR: And I think -- yeah. And the
21 court reporter we want to stay on, so --
22 MS. TURNER: I think, Mr. -- Mr. Wang, you
23 can turn off your video. Thank you.
24 THE CHAIR: And are there any preliminary
25 matters from the parties that we should deal with this
26 morning?

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1 MS. JAMIESON: None from Canadian Natural.
2 Thank you.
3 THE CHAIR: Okay. Thank you.
4 MS. BERG: And none from ISH, either.
5 Thank you.
6 THE CHAIR: Thank you.
7 So, ISH witnesses, I will just remind you, as your
8 counsel has probably already done, that you continue to
9 be under oath, and so I will turn you over for
10 questions from AER staff posed by, I believe,
11 Mr. Poitras this morning; is that right? Okay.
12 MR. POITRAS: Yes.
13 THE CHAIR: Thank you.
14 MR. POITRAS: Yes.
15 Alberta Energy Regulator Staff Questions ISH Energy
16 Ltd.
17 MR. POITRAS: So I have a couple of grounds
18 for clarification in a couple of different areas. I
19 think we'll start with the geology, so, obviously,
20 yeah, the panel, but I believe Mr. Mathison may want to
21 do the first go at these.
22 Q MR. POITRAS: So there was a significant
23 amount of discussion in cross yesterday about ISH's
24 description of B1. Early on in their submissions, ISH
25 had described B1 as a -- "continuous" over the KN06
26 box. And then in the reply submission, ISH had called

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the B1 mudstone "thin" and/or "absent" in the KN06 box. So I guess, just to start off, yesterday when you were in cross, you identified that -- your belief that the B1 mudstone is thin and/or absent in KN06. So can you comment on that discrepancy, Mr. Mathison?
A MR. MATHISON: Yes. The initial work that was done was done merely with well logs. I hadn't had reference to -- well, I had reference for core in the area, and they -- all of those had B1. So initially I did map it as being continuous. Once we looked at the core data provided by CNRL, we realized that there are places in there that the -- we would interpret -- and I think there's very good evidence -- that the B1 is missing. If you would like to go into a core, I can show you an example of that.
Q Do you think that would help your clarification?
A I do. I do.
Q Okay. So --
A Yeah.
Q I was just wondering; could you point us to a particular exhibit that you're thinking of?
A Sure. It's -- okay. I'll have to -- it's the -- the core is the 1AC/10-01. I don't have the PDF. Can you look up -- excuse me. I'll confer with my assistant, and my compatriot.
MR. LEWIS: I'll help.

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Q MR. POITRAS: And just to clarify, I'm talking about the B1 mudstone --
A MR. MATHISON: Yes.
Q MR. POITRAS: -- not necessarily the B1 sequence.
MR. LEWIS: So which well are you looking for?
MR. MATHISON: The 1AC --
MR. LEWIS: Let's see here.
MR. MATHISON: It's page 422.
MR. LEWIS: Okay. 422. This is -- this is -- sorry. The 53.02 Exhibit, PDF 422; is that correct? That's the one you were looking for, Mr. Mathison?
MR. MATHISON: Yes, that's correct.
MR. POITRAS: So you said 53.02.
A MR. MATHISON: This is the correct exhibit.
Q MR. POITRAS: Yeah. So I guess that would be page 10 of your opening statement?
A That's correct. Is it? I don't know.
MR. LEWIS: Let's figure it out. Six, seven, eight, nine, ten.
MR. MATHISON: No, no, no. It's not in the opening statement. That's --
Q MR. POITRAS: Okay. So if you could just give us the exhibit number and then the PDF page

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number.
MR. LEWIS: So it looks like it's Exhibit Number --
THE CHAIR: I think it's 53.02.
MR. LEWIS: Yes. And PDF Number 422.
THE CHAIR: Can we get that up on the screen, please.
MR. CAMPBELL: I wanted to clarify, Madam Chair. I believe that is one of the confidential exhibits.
THE CHAIR: Well, it's the -- the exhibit's not confidential. The whole data set was.
MR. MATHISON: How do I --
MR. CAMPBELL: Can you repeat the page number, please.
THE CHAIR: 422.
(SIMULTANEOUS CROSS-TALK)
MR. CAMPBELL: Sorry. I heard several people speaking there, and I didn't catch it.
MS. TURNER: 422.
MR. CAMPBELL: Thank you.
MS. TURNER: If we right click on it, it will turn.
THE CHAIR: So, Mr. Mathison, is this what you were looking for?
MR. MATHISON: Yes, it is. Thank you.

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Q MR. POITRAS: Are we almost better off just keeping it vertical?
A MR. MATHISON: No. That's fine. That's fine.
Q Yeah.
A I need the -- the pointers. Well, we can see where -- in the column -- one, two, three, four, five from the right, you can see the annotation is the -- we can see that -- where CNRL -- these are CNRL's picks; shall I call it that? And you can notice that they placed the base of the B1 mudstone at that position, and you'll see that they have -- the top of -- the top of B1 mudstone is also marked on there.
And you'll notice that the -- this -- this is an interlaminated mudstone and siltstone. And it is true that the B1 mudstone is a silty mudstone, but it's a highly bioturbated silty mudstone. This is the characteristics, at least, from what we can see on -- on -- on screen. I don't see any evidence that this is a highly bioturbated mudstone, so I think this is not -- I think they're -- they've made an error in this.
And if we'll look at our map for the area -- and it's Figure 3, so 63.01 --
MR. LEWIS: Yeah. PDF 12.
A MR. MATHISON: -- and PDF 12.

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Now, for some reason, I'm not able to point, but if we look where that core was from LSD10 -- and it's the one that's close to the west hand -- west side where we start to get thin B1, such as the ".02". So it's the well next to that ".02." And you'll notice that what we're looking at, the values around there are .2, .1 at the south -- at the south end, a couple of .1s. And we have these in core, so there's no -- you know, if you would like me to bring up one, I certainly could. It's --

Q I think we're good for that.

A Yeah, yeah. So, you know, I think that it's a reasonable interpretation given the information that we have. It -- it's very difficult to say for absolute certainty without the core, but it certainly does not look like it, in my estimation. And --

Q Is it --

A Go ahead.

Q Sorry. I actually just have one administrative -- I just got a note that the -- the court reporter is struggling a little with the cross-talk, so if you're conferring with any witnesses, just make sure to kind of have clear lines of demarkation between the -- the two.

And then the -- I have a follow-up question. Do you think it's possible for mudstone to change

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laterally?

A No question. Yes, yes, I do. Absolutely.

Q So the -- the main question -- and, again, we -- we had some back-and-forth about this in cross, in particular, the use of the B1 mudstone as a datum. So because of the undulatory nature of the base of the Wabiskaw D valley fill, to account for differential compaction and to have a datum close to the top of the McMurray B2 -- B2 valley fill, you use the B1 mudstone as a datum for correlation of stratographic cross sections. I was wondering if you considered using two datums for your analysis, one for the B2 valley fill and B1 sequence and another for the A2 mudstone up to the top of the Wabiskaw B.

A Well, certainly. Certainly. You know, as I say, those -- those original cross sections were made prior to this interpretation, when we thought the B1 was continuous.

And as I mentioned in the cross -- CNRL cross, that we also use -- you know, when you do these correlations, you don't just look at the mudstone. You look for the overlying and underlying strata. And I -- I feel confident that we can -- even though the B1 mudstone, which is a very thin unit in this area -- the base of the -- the overlying upper B1 is -- as CNRL refers to it, is a fairly -- fairly good pick too.

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So, you know, we -- we're not distorting things much, but -- but, yes, I -- I'm in full agreement. I think we -- you know, using multiple horizons is -- is the way to go.

Q So I'd like to -- I'll refer Mr. Campbell to ISH's opening statement because I'd like to go through a couple of your core interpretations. In particular, I'll have -- I'll direct Mr. Campbell to paragraph 42 of that opening statement.

So we have here -- moving up further in the core for the 02-01 well, I would like to begin with the second column from the bottom. If you look to the left of the core, near the top of the column, you will see highly distorted strata. The sedimentary layers are broken and lack continuity.

So are you saying this is a fault?

A I'm not saying that's a fault. I'm saying there's disruption of the core.

Q So if I could just -- sorry. If I could just have Mr. Campbell just scroll down to the -- the core at the bottom of page 10 here. Perfect.

A M-hm.

Q Sorry, Mr. Mathison. Continue.

A No. That's fine.

Q Would you say, looking at that, is it possible that that's a redeposited mud clast?

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A No, no. I don't believe so. You can see that the -- that that -- if it's -- if it is a clast, it's broken, that -- that you can make out that it's actually warped up, and you can see that the underlying mudstones are bitumen-saturated, and so it has been brought up into that. So I -- I don't -- I would not interpret that as a clast.

And the other thing is: We're -- we don't see that sort of scale of clast in this -- in this depositional environment.

Q So just to be clear, are you saying it's not possible or it's not probable?

A I'm not -- I'm saying it's not probable.

Q Okay.

A I -- yeah.

Q So I'm going to get Mr. Campbell to head down to paragraph 46.

So, finally, moving to the centre of the second column from the top, just to the right of the red line below it, there's a sand-filled structure which indicates that the timing of the fracturing occurred after oil migration and degradation into bitumen.

A M-hm.

Q Is there an alternative interpretation for this other than it being called a "fracture"?

A Yeah. You could -- I mean, again, I -- I've seen this

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in many cores, and in this -- the typical ichno fauna in this is cylindricus. I don't see a lot of skolithos. And this would be -- the only alternative is this would be a large skolithos. But I find that these things are -- are very prevalent in this area, and they also occur in mudstones, and -- and -- and -- and so, therefore, I believe that these -- now, without being able to sit and look at the core, it's -- it's very difficult to say definitively, but I -- in my opinion, these are probably oil -- these are probably sand-filled -- filled fissures, fractures in the core.

Q Is it also possible that it could be a vertical burrow?

A Well, that's -- that's -- that's what a skolithos is.

Q Yeah. Okay.

A It's a vertical burrow.

Now, when you get -- when you get up into the Wabiskaw C, that one has abundant vertical burrows, and they're large, and they're -- they penetrate very large distances. This is a highly restricted environment, and, yes, skolithos can exist in that environment but typically not the robust forms or -- or the -- the large penetrations that we see in here -- or what we would interpret these as, as fracture fills, and -- and the -- the fact that they occur in the mudstones also, I think, precludes that. And, you know, they -- they occur in swarms associated with vertical fractures

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in -- that -- that penetrate in -- that we can identify through other means, like offset of sedimentary layers and stuff like this.

Q Do you see a lining along that?

A No.

Q No?

A There's no lining.

Q So let's go down to paragraph 47.

A M-hm.

Q And we'll scroll down just a little bit more just so we can have the -- the picture in there as well.

So, finally, moving to the top of the McMurray and the base of the Wabiskaw D, if you look to the bottom of the column on the right-hand side, we see highly deformed strata that have been cut by small-scale fractures.

MR. POITRAS: So, Mr. Campbell, if I could just get you to scroll down a little bit more.

Q MR. POITRAS: So we have that -- that bottom core. Is there an alternative explanation for this other than resulting from a fault?

A MR. MATHISON: I -- I don't think so. You know, anything that I've seen in the -- the McMurray A -- and that's what this is -- it comes in; it's -- it's very flat; it's very uniform. This is highly anomalous, and you can see -- I would -- I would argue

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that this -- this -- this piece of strata has actually been rotated in place.

And -- and then you can see -- you can also notice, at the very bottom of it, it's offset by very small fractures, so -- and it can't be coring-induced because -- because it's -- there's no break in -- in the -- in the stratigraphy above and below. It's continuous, but yet, you know, this is -- this is a highly unusual situation -- a highly unusual piece of core.

Q Is it also possible that this is a sin, to post depositional slump?

A Well, from my -- my inter -- my knowledge of this unit, I have never encountered anything like that, and I -- I suppose that is a possibility, but it looks more to me that, you know, because the mudstones underneath are deformed also, if you -- you would expect that the -- you're either going to see -- no. And -- and then the overlying strata is also deformed, so, no, I -- I don't believe it is. It is a possibility, but I -- I don't believe it is.

Q Okay. And then -- so the last one I have here on the cores is paragraph 48. So if you move to the top column just to the left of the 467 marker, you see a vertical fracture which extends upward. This is a post-bitumen fracture. Is there an alternative

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explanation for this other than a post-bitumen fracture?

A Well, I would argue no. I think that it's -- it's -- it's pretty obvious that the bitumen had to be in place and that this fracture is -- it's fairly large. It's -- it's probably at least 40 centimetres, and it -- it disrupts the stratigraphy. You know, I think that the -- the best interpretation would be that this is a post -- post-bitumen structure, post -- and post-biodegradation structure.

Q Sorry. Just to make sure we're on the same page, we're talking about that vertical line just to the left of the 467 marker?

A Yes, yes. Yeah.

Q Is it possible that this one could also be a burrow?

A No. Definitely not. This offsets the -- the stratigraphy across it, the -- you can see the layering, especially in that lower unit, has been displaced. It's only been displaced by a few centimetres, but the -- the one to the lower side is actually offset at least a couple of centimetres down -- down to the -- to the right, so -- no, no. That's -- that's -- that's clearly -- that's clearly a -- a -- a fracture that -- that is intercepting this stratigraphy.

Q All right. Last question. If you could just have

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1 Mr. Campbell -- or if you could just direct
2 Mr. Campbell's little hand here to precisely the -- the
3 one you're talking about.
4 A So just at the 467.
5 Q Yeah.
6 A Okay. Go up to the top of 467. Okay. Just come down.
7 Now go over -- no, no, no. Just have a little -- a
8 third of the way through the core box -- not box, but
9 column, and just go a little bit over, just a tiny bit.
10 Yeah. One more. Okay.
11 You'll see this -- okay. The sand layer with the
12 mudstone on top of it, and if you look to the top of
13 the screen, I would argue that those two probably are
14 connected when we see the sand layer and then the
15 overlying thin mudstone. And then above it, we see a
16 sandstone and a thin mudstone that is -- and there's an
17 offset of a few centimetres. Do you see what I'm
18 looking at?
19 Q Yeah, yeah.
20 A Okay. And we can move up a tiny bit.
21 Q If we can just zoom in --
22 A Yeah. If you could zoom in, that would be great.
23 Q Oh, yeah, yeah.
24 A That's perfect. There. You can see it there. Okay.
25 You can see that there's a number of fractures --
26 actually, a number of fractures coming through there.

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1 If you look just immediately to the -- to the left of
2 that, you can see that that one is offset, but you'll
3 notice that there's actually a number of -- a whole
4 number of fractures. Do you want me to guide the --
5 Could you just go very slowly over to the left,
6 please. Just a bit more. Just a bit more. Yeah,
7 yeah. Keep going. And keep going into this thick
8 sand. Yeah. Now come down. You can see that that --
9 there is -- oh, if you just go down just a little bit
10 lower.
11 Just above there, there's a number of fractures
12 coming through. There's at least three fractures that
13 intersect that -- that sand, and you can see that
14 they're -- they're marked by -- by little bits of
15 mudstone. So I -- I would say there's a number of
16 fractures, actually, coming through that.
17 Q So I guess my last question --
18 A You can see -- yeah.
19 Q Yeah, yeah. So I guess --
20 A M-hm.
21 Q -- my last question for you: Is it possible that some
22 of the fractures you've identified have alternative or
23 possible interpretations?
24 A Well, I think that that's -- yeah. That's fair enough,
25 but I think the -- the -- the -- the weight of evidence
26 would indicate that these are more -- more likely

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1 fractures, and, in fact, we have abundant evidence of
2 ones that are, you know, incontrovertible. You know,
3 we know that they are fractures, and, in fact, we can
4 see conjugate fracture sets.
5 Q Okay. Thank you, Mr. Mathison. I think that's all I
6 have for the geology.
7 A Great. Thanks.
8 Q I believe Mr. Leech may want to take these questions
9 because this is about the wellbore integrity issue, but
10 obviously anyone on ISH.
11 Does ISH have any data that indicates the
12 gas-over-bitumen zone in the Kirby Upper Mannville II
13 pool may be in communication in other gas pools?
14 A MR. LEECH: Okay. Are we here?
15 Q Okay. I can hear you.
16 A Can we repeat the question, please.
17 Q Absolutely. Does ISH have any data that indicates the
18 gas-over-bitumen zone in the Kirby Upper Mannville II
19 pool may be in communication with other gas pools?
20 A That's theoretical at this point in time. We show that
21 the GOB has been flowing, but we don't know where it's
22 going exactly. We have some theories to that. It
23 could be going up to the Upper Mannville HH pool behind
24 pipe. So we don't have any real proof of the -- of the
25 GOB flowing into anything else.
26 Q Sorry. Just so I understand, so you're just saying

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1 it's a theory that the II pool is connecting to the HH?
2 A That's right.
3 Q Is there enough data to determine if there is or
4 isn't pressure communication between the Kirby Upper
5 Mannville pool and the McMurray?
6 A And the McMurray?
7 Q Yes.
8 A So communication with the lower zone?
9 Q Yes.
10 A There is a suggestion of that in the data and in the
11 evidence.
12 Q What would you say that -- where in the data would you
13 say that suggestion is?
14 A That's at 48.02 -- 48.02, page -- I believe it's a
15 table -- yes. The table on page PDF 49.
16 Q I'm just waiting for it to load up here.
17 A M-hm.
18 Q Actually, if I could get Mr. Campbell to put that up.
19 For some reason, mine's not opening.
20 MS. TURNER: There's a small glitch in
21 screen sharing, so -- this is Tammy. I'm going to
22 share it. Bear with us. Sorry about that.
23 A MR. LEECH: Very good. So if we scroll
24 down a little bit to the bottom of the table, Point
25 Number 8. So in the first box, Point Number 8, 24th of
26 June '20, we read at the bottom there: (as read)

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Pressure in the Upper Mannville II pool is now higher than what it was when monitoring first initiated in March 2019.
So between March 2019 and the final shut-in event at 10-01, we had ten months of supposed depletion from the well, and I don't understand how after ten months of depletion a reservoir pressure would be higher.
Q Would you say we have enough data on this point?
A No.
Q Why don't we have enough data?
A We haven't tested for it.
Q Is that because the -- the II pool has been shut-in?
A Well, the II here, at this point, 10-01, we suggest that it's been flowing someplace.
Q Is there any other pressure data for the II pool?
A Not that I'm aware of, other than the occasional operator taking a wellhead pressure.
Q So we're going to move on to a different topic here. Just give me a quick second here.
So ISH had previously considered SAGD -- SAGD start-up in KN05 for that -- for the pressure and temperature gauge data in 10-01. Is there enough data to determine if there is or isn't pressure communication between the --
It's a bit of a tread of the follow-up question. I'm going to move on to the next question. If

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communication did exist over the gas over bitumen in the Kirby Upper --
THE CHAIR: Mr. Poitras?
MR. POITRAS: Yes?
THE CHAIR: Just slow down a bit for the court reporter.
MR. POITRAS: Yeah.
Q MR. POITRAS: If communication did exist between the gas over bitumen in the Kirby Upper Mannville II pool and the McMurray, what impact would this have on SAGD operations, and what could be done to mitigate those impacts while also mitigating impacts to the gas over bitumen in the Wabiskaw B in the Kirby Upper Mannville II pool?
A MR. LEECH: Is that a question for me?
Q I guess to anyone on ISH.
A MS. GIRY: So I think the question was -- maybe you want to repeat it a third time. I'm sorry.
Q Yeah. If communication did exist between the gas over bitumen in the Kirby Upper Mannville II pool and the McMurray, what impact would this have on SAGD operations, and what could be done to mitigate those impacts while also mitigating impacts to the gas over bitumen in the Wabiskaw B in the Kirby Upper Mannville II pool?
A So the first part of the question is related to the

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impact on SAGD operations? I'm just trying to -- if I get it right?
Q Yeah.
A I think I would prefer to defer to CNRL on that one. My experience -- I would have some generic comments, which probably are not of very much interest to you, but I assume operators would call that a (INDISCERNIBLE), and so it could lower the pressure, and they would have to monitor the steam chamber. And clearly, like, monitoring the steam chamber is how they would enhance the SAGD operations. The whole point of SAGD operations is making sure that the steam goes where you want it to go, down -- they want the steam to go to the GOB zone.
So your second part of the question is related to the impact on the GOB zone. So, of course, given that the layers between the McMurray B2 and the GOB zone are not proven to be continuous or competent, given that there is a wellbore integrity issue proven between the GOB zone and the Mannville HH, we can infer, assume -- it's an assumption -- that there is a leakage pathway between the McMurray and the GOB zone. Leakage pathway could be through the 10-01 well with the leakage behind casing, or it could be through incompetent layers.
Q So I guess if I could just --

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A Sorry. And then --
Q Yeah.
A -- I will complete the question because you asked for an impact.
The impact would be once a steam chamber grow -- grown, yeah, those steam chambers tends to develop some sour gas on top of them by upgrading somehow the bitumen, and the -- it's proven that sour gas is often accompanied with SAGD operations, and if sour gas was to leak into the GOB zone, of course, the whole GOB zone would become sour. And the GOB zone, the wells, the facilities are not at all equipped with sour operations -- sour facilities; hence it would render this operation extremely unsafe to continue to produce. It's a safety issue at this point.
Q So if there was no leakage through the 10-01 well, would there be pressure communication between the SAGD operations and the gas over bitumen?
A So the -- then that's a second leakage pathway, through the incompetent layers and things. There could be pressure for --
Q I guess -- sorry.
A Sorry. I probably didn't understand your question 'cause I felt I ...
Q I guess what I'm chiefly getting at is: Did you consider repressurization -- putting aside the 10-01

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1 issue, would gas repressurization help curb vertical
2 steam chamber growth?
3 A That's probably a question for CNRL. You know, we are
4 a gas-only producer. We stay away by -- by a decision,
5 away from SAGD, away from sour operations. So our
6 purpose is to produce gas, and, generally, we tend to
7 avoid to inject it back. So it's not our business.
8 Q Okay. So I do have some general questions about
9 souring. So ISH has obviously referred to souring of
10 its gas as a risk arising from Canadian Natural's
11 proposed operation. What specifically can you tell us
12 to help understand the risk? More specifically, is it
13 correct to assume that the Wab B gas is not sour right
14 now? And I guess we can expand that question. Do we
15 know what the sour concentrations are right now in the
16 gas-over-bitumen area?
17 A So the gas over bitumen is absolutely not sour. So
18 there's no trace of H2S in that gas. If it had -- I'll
19 check with my colleague from operations but -- just to
20 remember. One minute -- one second.
21 Q Yeah.
22 A So the last analysis from the GOB gas was prior to
23 2004, of course, and I don't have it with me, but
24 there's no trace of sourness over there.
25 Q I guess, just at some point, for the Panel's benefit,
26 if we could get an evidentiary reference for what the

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1 sour gas levels -- whether they're zero or whether
2 they're on a negligible amount, just any sort of
3 evidentiary evidence for when they're reviewing later.
4 A Yeah. And just checking -- oh, sorry. Let me check
5 with my team again.
6 Okay. I just wanted to --
7 THE CHAIR: Sorry. Before you answer,
8 Ms. Giry, can I just ask you; when you say you're
9 checking with your team, can you just tell us
10 specifically who you are checking with?
11 MS. GIRY: Yeah. Absolutely.
12 THE CHAIR: Thank you.
13 MS. GIRY: I just checked with Mr. Ward
14 and Mrs. -- Ms. -- Ms. Clee.
15 THE CHAIR: Thank you.
16 A MS. GIRY: And now I asked them if we had
17 any evidence currently at hand in our -- in all these
18 binders, and, no, there's no -- nothing that would
19 answer your question immediately.
20 Q MR. POITRAS: Okay. So now we're getting to
21 a little bit -- the overtime analysis. Is the risk of
22 souring on start-up, or does it evolve over time?
23 A So the risk of sourness -- sour evolves with time.
24 Basically, when the steam chamber is developed -- not
25 necessarily mature but definitely developed, it will --
26 the heat, inside the steam chamber, above 200, 250

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1 degree, will kind of upgrade the bitumen and form this
2 sour gas at the top of the steam chamber. So the issue
3 is not at the initial start-up phase. The issue is
4 along the lines from the development, and it can happen
5 quite fast.
6 KN05 is located 150 metres from 10-01. We are not
7 certain -- as we could explain, we think there are
8 incompetent layers -- layers above the GOB, and so on
9 the -- during the life of the SAGD operations, it could
10 happen quite fast because of the 10-01 integrity issue.
11 Sourness could reach GOB gas.
12 Q Again, I guess, for the Panel's benefit, can you point
13 us to any of the evidentiary record where there's a
14 risk assessment over time.
15 A Yeah. I assume it was -- that's -- I apologize. I
16 have so many pages.
17 It starts on 63.01. It's -- yeah. Well, it
18 starts -- let me give you the article -- the article.
19 Article 101 it starts.
20 Q Can you give me a PDF page number.
21 A Oh, sorry. PDF page 46 from 63.01. And, more
22 precisely, our estimation of the risk ranking is on
23 page 49.
24 MS. TURNER: Excuse me, Madam Chair.
25 I believe that's Exhibit 63.02.
26 MS. GIRY: Oh, sorry. You're right.

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1 Yeah. I'm sorry. I combined the two, so ...
2 THE CHAIR: It's those cover letters
3 always causing problems.
4 MS. GIRY: Yes, I agree.
5 Q MR. POITRAS: So thank you for that
6 reference.
7 My next question: Is there a lateral variation of
8 sour grass -- of sour gas across the Kirby Upper
9 Mannville II pool that can be mapped?
10 A MS. GIRY: Sourness variation in the
11 Upper Mannville? There's no sourness in the Upper
12 Mannville II. In the future, you're asking?
13 Q Yes. So I have -- is there a lateral variation of sour
14 gas across the Kirby Upper Mannville II pool that can
15 be mapped?
16 A So presently the Upper Mannville II pool is not sour,
17 and so in the future, when steam -- sour gas and steam
18 chamber reach -- encroaches with the Mannville II, gas
19 analysis at the observation well or gas well monitoring
20 would detect that sourness.
21 Q So --
22 A And the mapping could be obtained, I guess, but, again,
23 I'm not an expert in seismic -- with the 4D seismic.
24 Q So that leads into my next question: What would be the
25 best way to demonstrate if the gas resource was souring
26 over time?

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A Through an observation well and the gas analysis, the composition of the gas. Gas well monitoring with the gas analysis and the composition of the gas.
Q And my last question for ISH: Do you know of any analogues of souring of an overlying gas resource due to steam-chamber loss of containment?
A So the -- kind of analogue proving the aquifer rises. Surmont -- Surmont, it's a gas cap over bitumen, so in terms of geology, it's not analogue. But given that we have a breach in the containment through the well 10-01, there is communication of sourness from the steam chamber to the gas cap consumed. There has been measurements. I could guide you to the evidence if I -- if you want.
Q I think we're good. Like, do you know of -- outside of this particular area, if there's any analogues of souring of an overlying gas over bitumen?
A So it's widely, largely reported the -- what -- aquifer rises phenomenon that basically steam in bitumen is upgrading bitumen, creating this sour gas. So whenever there would be a gas cap, a loss of containment of the steam, there would be sourness of this above radius.
And at the end, if there's no -- at the worst-case scenario -- the worst-case scenario, there's no sealing or a breach in the -- if there is a breach in the well, we could fear for the worst, but I don't even want to

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mention that. At Surmont, they were going to detect sourness of 4,000, 3,000 ppm at surface at the -- at the field site.
MR. POITRAS: Okay. I'd like to thank Mr. Mathison, Mr. Leech, and Ms. Giry for your answers.
That's all I have, so I will now pass it over to Madam Chair.
THE CHAIR: Thank you, Mr. Poitras.
So, Ms. McKinnon, do you have any questions for ISH?
MS. MCKINNON: I do have one question, Madam Chair.
Alberta Energy Regulator Panel Questions ISH
Energy Ltd.
Q MS. MCKINNON: It relates to CNRL -- Canadian Natural's request for 7 MPa start-up pressure for a -- over a period of time of 14 days, and my question is how that pressure would affect the steam-chamber growth over time and whether there is a way to mitigate that if it is a lower start-up pressure.
A MS. GIRY: So I will take that question. So the start-up pressure of 7 MPa at the depths of KN06 would present 14.7 kPa per metre as a pressure gradient. So it's above the minimum stress gradient measured by CNRL at March 2020 at this level. So it could and it did, like, create a hydraulic fracture, as

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it was -- as it was mentioned yesterday, in one of the well.
Then further on, when the steam -- well, as you said, it's -- it's only during the 14 days -- so the first 14 days. So once the steam chamber is in place, it's -- it's not applicable anymore, and the operating pressure drops to 6 MPa. That's my understanding.
Q Thank you.
THE CHAIR: Mr. -- or Dr. Zaitlin?
DR. ZAITLIN: Yes. Thank you, Madam Chair.
Q DR. ZAITLIN: Just a joint geology/geophysics question for Mr. Mathison and Mr. Vermeulen.
In -- in the opening statement in 86.02, page 98, you presented a two-well cross section -- a structural cross section in which you interpreted the presence of a fault offset between two wells, that 06-01 well and that 07-01 well. And at the base of the 06-01 well and at the base of 07-01 well, you identify two low-resistivity zones or 'T' zones that was indicative of a hydrocarbon water contact. The cross section that you presented shows that most of the markers, which were the coloured lines on that cross section, were basically parallel to each other and that the isopach thicknesses was relatively consistent between the two wells.

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My question would be: What would've happened if, instead of presenting that data as a structural cross section, you presented it as a stratigraphic cross section on a marker above the McMurray channel reservoir facies?
A MR. MATHISON: I think I can answer that. There wouldn't have been a lot of difference, you know, 'cause, as you say, the -- the markers come across pretty -- pretty uniform, especially if we hung it on the Wabiskaw A, let's say. But I think -- I think, which -- it really emphasizes that there's something happening between the 07-02 well and the 06-01 well. To get that discrepancy in the oil water contacts, you know, is -- I -- highly unusual; let me put it that way.
Q Would you agree that there's about a 7- or 8-metre difference in thickness between 07-01 and 06-01 at the McMurray level at the sand?
A I don't think we're on the right -- this is not -- sorry. We don't have up the correct one.
Q This would've been on page 12 of your opening statement.
A Yeah, yeah. And I -- you know, I -- from memory, I think that's correct.
Q That's right.
A I -- I actually measured it at 7.5 metres, so we're in

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1 the same ballpark.
2 Q Would you think that -- would you think that those
3 McMurray sands are a one-channel fill or a series of
4 stacked compound-channel fills?
5 A Yeah. No. In this instance, no. These are just
6 single -- single channels. It's not a composite
7 channel.
8 These channels are much smaller than what we see,
9 like, just over at -- you know, going along the main --
10 main, you know, trend where you do get the -- the
11 stacked channels. This -- this is just a single
12 incision and -- and fill. It's a relatively small
13 feature. I've worked on a number of these. They're --
14 you can readily -- readily map them out. There's --
15 you can tell by the -- your -- there's no other level
16 of incision in this area other than the overlying
17 Wabiskaw.
18 So, no, that's a single fill. So we don't have
19 any barriers in there that would -- would, you know,
20 cause that difference in -- in the oil water contacts.
21 Q So your interpretation would be that this is a
22 homogenous fill of sand with one channel --
23 A Yeah.
24 Q -- up to 30 metres thick, in --
25 A Yes.
26 Q -- which the variation in the hydrocarbon water contact

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1 is due to a structural dislocation?
2 A Yes. And -- and -- which is consistent with what we
3 see in the overlying strata.
4 In fact, we can trace those up -- in this
5 instance, up to the top of the Mannville. And in this
6 area, we have dislocations that go up beyond -- higher
7 than the base of fish scales, and the offset is
8 consistent amongst those various levels. So I think
9 the most reasonable interpretation is that these are --
10 this is due to some -- some form of structuring, and we
11 also see evidence for that on the seismic cross
12 sections. In fact, their cross sections demonstrate
13 that what we're seeing is actually real.
14 Now, I -- I misspoke on the previous because we
15 didn't have the -- the right cross section up. If we
16 return that to horizontal, if we hung it on top of
17 Wabiskaw or -- or even base of the Clearwater, what
18 would happen is that oil water contact would be
19 constant across the area, so -- which suggests that
20 that's an original oil water contact that has been
21 displaced.
22 Q So that was a good segue to the companion geophysical
23 line that was on the next page, and that would be to
24 Mr. Vermeulen.
25 On that WW cross section -- that was CNRL's
26 Tab 34. Between the McMurray incision top and the

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1 Paleozoic, between the 06-01 and the 07-01 well, can
2 you -- can you indicate whether you see any
3 through-going displacement between those two wells?
4 THE CHAIR: Shall we bring that up on the
5 screen?
6 DR. ZAITLIN: That would be in 86 --
7 MR. MATHISON: Yeah. Please do.
8 DR. ZAITLIN: -- 02, page 13. Are we having
9 an issue?
10 THE CHAIR: Ms. Turner or someone who's --
11 who's got control of what we can see, can we please get
12 Exhibit 86.02, page 13, up on the screen?
13 MS. TURNER: Yes. I'm -- was sharing it at
14 one point.
15 Q DR. ZAITLIN: So I'll just repeat the
16 question so we know what we're asking.
17 Between the McMurray top and the Paleozoic markers
18 that's on that cross section between the 06-01 and the
19 07-01 well, can you indicate on that seismic section
20 slice any evidence of displacement? I -- I recognize
21 the inflexion point below, but do you see any
22 displacement in the seismic signature between these two
23 markers?
24 A MR. VERMEULEN: So I -- I do not see any
25 displacement, no, but I would argue that a further
26 analysis of the amplitudes as they vary, you know, away

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1 from this section would need to occur. From this
2 section alone, from this evidence, I will remind you
3 that I didn't have access to analyze the data other
4 than looking at this section, and in my experience, I
5 would say that features of such a small displacement,
6 7 metres, on seismic shot with these parameters would
7 be very difficult to see visually, and you'd need to
8 dig into your geophysical toolkit to analyze further.
9 So from -- from this evidence, I -- I can't say that
10 definitively if I could detect that there's a 7-metre
11 displacement.
12 Q Okay. Would you say that the yellow highlighted
13 portions of the two well logs is equivalent to the sand
14 in the McMurray that was shown in the previous
15 geological cross section that Mr. Mathison spoke to?
16 A Yes.
17 Q Yes. And you can -- can you relate those yellow zones,
18 the sand, to the top-loaded and bottom-loaded seismic
19 couplets that are associated with that seismic line?
20 A Again, without having a seismic well tie in front of me
21 for this specific well, I wouldn't be able to answer
22 that question.
23 Q Is it possible that the change in colouration, the dark
24 and light couplets that you see there, may relate to
25 individual channel fills within the overall McMurray
26 incised valley?

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1 A Again, I'm going to have to say that without having a
2 seismic tie, I -- I can't speculate on that.
3 Q Okay. That's fair.
4 So, basically, we're expanding through the data
5 set beyond its resolution?
6 A For sure.
7 Q Okay. Fair enough. Thank you very much.
8 DR. ZAITLIN: That's it, Madam Chair.
9 THE CHAIR: Okay. Thank you.
10 Q THE CHAIR: I do have a few questions.
11 I've been able to cross some off my list, and I will do
12 my best to edit as I go.
13 Mr. Mathison, I think my first one looks like it's
14 for you. I want to understand a little better, for my
15 own purposes, the relevance -- or potential relevance
16 of the thickness of the B1 mudstone or if your issue is
17 not a variation in the thickness of it; it's actually
18 the fact that under your interpretation, you say that
19 there are some places where it's absent in the KN06
20 box.
21 So let's start there. Is the thickness of the B1
22 where you say -- mudstone where you say it is present
23 an issue in and of itself, or is it the fact that you
24 say it's absent in some spots?
25 A MR. MATHISON: Actually, both. When we're
26 looking at something that we can see in core is, you

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1 know, 10 to 15 centimetres or 20 centimetres thick,
2 that's -- I would not consider that to be much of a
3 barrier to steam, you know, especially if -- if it's
4 offsetting an area that we believe and have mapped as
5 where it's absent.
6 So the other thing is -- is, you know, given that
7 we identify -- and I stand behind this -- a lot --
8 pervasive fracturing, both pervasive and abundant
9 fracturing, if those thin mudstones have been fractured
10 and brecciated, then their mechanical integrity has
11 been compromised, so, therefore, I think, with any --
12 with any steaming that they would not provide a
13 mechanical barrier.
14 Q Okay. Thank you. That was helpful.
15 A Thanks.
16 Q The next one was also for you.
17 THE CHAIR: If we could bring up, please,
18 Ms. Turner, Exhibit 63.01, page 10.
19 MS. TURNER: One moment.
20 Q THE CHAIR: And it -- we'll be looking at
21 paragraph 15, where it says: (as read)
22 Given this, the lateral extent of individual
23 his in the KN06 area can be calculated based
24 on the thickness of 7 to 12 metres and a dip
25 of 8 degrees. This gives a lateral extent of
26 50 to 85 metres, far less than the width of

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1 the reservoir and less than interwell
2 spacing.
3 So maybe -- so that was -- so my question is: How did
4 you arrive at that?
5 A MR. MATHISON: I -- it's simple -- simple
6 geometry.
7 Q Okay.
8 A Cosine of 8 degrees times the thickness of the
9 interval.
10 Q Okay.
11 A And, you know, 8 degrees I got out of the Fustic paper,
12 and that's pretty well-recognized within the industry.
13 So, you know, it's a simple -- simple calculation.
14 Q Okay.
15 A And I base my interpretation and the use of this on
16 what Fustic and -- et al., the 2011 paper that CNRL
17 thankfully -- or we are grateful that they included as
18 it's very relevant. They -- they made these same
19 calculations, and they were dealing with his that are
20 in the vicinity of up to 17 metres thick, and they
21 calculated a maximum extent of those as 285 metres.
22 So, you know, it's -- it's -- yeah. As I say, it's
23 just a simple calculation.
24 Q Okay.
25 A So -- and, you know, I think, basically, the issue
26 is these things are dipping. It's an 8-degree dip,

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1 which is not a -- not a high dip, but given that -- you
2 know, the thinness of these layers, they don't extend
3 for a long -- long distance.
4 And, you know, I don't -- I'm not certain exactly
5 what the well spacing is. It's probably 50 to 100
6 metres -- maybe 100 metres. So they're in the range of
7 the spacing between two wells.
8 Q Thank you. That's helpful. I don't like to assume. I
9 had what you described --
10 A Right.
11 Q The image in my mind was I'm back in grade -- I can't
12 remember what it would be --
13 A Yeah, yeah, yeah, yeah. No. It's --
14 Q -- geometry but I didn't want to assume.
15 A No, no, no. And I understand that.
16 Q Okay. Thank you.
17 So my next question -- Ms. Giry, this may be for
18 you, but I will let your panel decide. So, again, the
19 same exhibit, 63.01, pages 45 to 46, and specifically
20 paragraph 101.
21 MS. TURNER: Madam Chair, I just want to
22 clarify that is Exhibit 63.02.
23 THE CHAIR: Okay. Sorry. I've got the
24 cover letter issue myself. So, yes, 63.02, paragraph
25 101.
26 Q THE CHAIR: So my question has to do

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with -- with leakage pathways and what -- what you can tell me to help, again, get a better picture of what you're identifying as the risks. So if we're looking at baffles -- assuming we're looking at baffles and not barriers, is your concern that the steam chamber would reach the Wabiskaw B at multiple points versus potential multiple leak pathways, or are you concerned about -- so I'm thinking about during steam-chamber development, not at start-up. Are you -- or are you concerned about a single-point breakthrough or both?

A MS. GIRY: So -- so you are first very correct to mention that it's during the lifetime of the SAGD operations and not necessarily only during the start-up operations.

And to your point, we've identified at least two leakage pathways, the one that would go through the strata, which are not competent or absent, and the one that would go through a wellbore integrity -- or compromised wellbore.

Q Okay. So with the first one, following strata pathways, does it make -- I guess what I'm trying to imagine -- I -- I'm visual, so I'm trying to imagine in my head. I can see the steam chamber growing. If there were pathways, is -- is there the potential for multiple pathways to reach into the Wabiskaw B, or is your concern a single interconnected pathway of --

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A So during the SAGD operations, there will be, of course, thermal expansion of the bitumen. There will be compaction when that bitumen is produced and the steam-chamber pressure is modified, and I don't know how it's planned there. From the geologic point of view, there are layers that are not continued, and so, particularly, it was mapped, as we showed earlier on the map, that the B1 was missing here and there, that the A2 was missing in the northwest corner. And so the -- the steam chamber and the gas -- the sour gas that will be at the top and above it will follow the least-resistant pathway, and so wherever there's a -- a lack of resistance, like, there's nothing physically to hold it where it is, it's going to go.

And so visually -- I'm pretty visual. And so the steam chamber grows on top of it. It's super hot. Bitumen is upgraded. It forms some sour gas. And this sour gas will go to the top because that's the purpose of gas, and it will find a pathway of least resistance. Whether it's a broken rock or fault, whether it's an absence of a layer, or if it's a wellbore integrity issue, it's going to get where it wants to go, which is the top.

Q Okay. I'm maybe not being clear enough, but I think I have enough there to --

A Sorry. That was maybe too visual. Sorry.

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Q No. It wasn't too visual at all.

I guess my question is: Is there potential for the steam chamber and, potentially, sour gas to reach the Wabiskaw B through multiple --

A Yes.

Q -- weakness points if --

A Yes.

Q Okay.

A Sorry. My -- my -- yeah. I meant -- "yes" is my answer.

Q Okay. And then so how would an observation well in addition to the 10-01 well help?

A Well --

Q Where do you put it?

A Yeah. Well, I would put it in the most vulnerable location.

Q Okay.

A So vulnerable locations that will show -- could be the absence of A2 in the northwest, could be why the B1 is not there. Maybe several observation wells, clearly the most vulnerable locations.

Q And can you get information from an observation well that allows the parties to be proactive rather than reactive? So can you get an early warning system to avoid, I'll call it, entry into the Wabiskaw B gas, or do you have to wait until it gets there and then react?

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A No. The -- the purpose of observation wells is, of course, to monitor pressure and temperature, and we've seen in some of the exhibits, like among the (INDISCERNIBLE) 54 presentations from CNRL, that you can run (INDISCERNIBLE) in those observation wells, and that clearly tells you where -- the steam chamber and how it progresses, and so that's the purpose observation wells. It's initially to ensure good conformance of the steam, and if steam is not conformed as you want, well, it definitely indicates that it's not going where you want.

Q And I think this is also for you, Ms. Giry. Again, Exhibit 65 -- it's probably .02, not .01, page 27 out of 45. Canadian Natural --

A 65?

Q Yeah. I believe -- I believe this was their responses to AER's requests for information.

A Correct. Page? Sorry.

Q Page 27 out of 45. It's where they say: (as read)

Canadian Natural has decided to commit to the following enhancements.

A I've got it. Yes.

Q So my question is: Do the specific elements of Canadian Natural's commitment address any of your concerns, or do the commitments as a whole address your concerns? And if they don't, what specifically is

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1 missing?
2 A So I remember -- yeah. I'll just check with that.
3 Q So I think you need to scroll down.
4 A Yes. So that's a third -- yeah. Okay.
5 And so I will say, my first answer is: I didn't
6 find -- well, I was hoping that this was already in
7 place. I -- I couldn't see, really, the enhancement.
8 I was by reading the produced submissions understanding
9 that there were already conference or meetings -- I
10 don't know how it looks like -- to determine the
11 evolution of the start-up operations. I'm still
12 unclear why, after the well is unloaded, we still have
13 to have those high pressure. I don't -- I will get
14 further answer, for sure.
15 So I will insert that I don't see any -- much
16 enhancement in that proposal.
17 Q So, sorry, just to make sure that I understood you. So
18 when you read this, what you see are things that they
19 are already doing?
20 A Let me -- give me a minute -- or a few seconds --
21 Q Sure.
22 A -- just to review the viewpoints.
23 Q Yeah.
24 A Thank you.
25 Sorry. I just read it. So what -- what they're
26 doing here is definitely monitoring. I don't know if

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1 it's enhanced compared to what they are currently
2 doing -- have done for KN02, KN05. It's monitoring.
3 It's not mitigation. If it fracs, it's done. So the
4 only mitigation I can see is to avoid starting up at
5 the pressure above the minimum stress gradient and at
6 the KN06, that will be to start at below 6 MPa.
7 Q Thank you.
8 Mr. Vermeulen, I think this question is probably
9 for you. So if we go to the opening statement, so
10 86.02, and page 21. It's the semblance slice. You've
11 got that in front of you?
12 A MR. VERMEULEN: I do, yeah.
13 Q So my question is: You had pointed yesterday to linear
14 anomalies or features showing on this semblance slice,
15 and you were suggesting that they were due to faulting
16 or perhaps -- well, I think initially your main point
17 was -- was faulting or some kind of significant linear
18 structure. What else could these be attributed to?
19 A Without -- I think the point that I had made in 66
20 where I say that: (as read)
21 A further review of semblance slices above
22 and below the mid-B1 level would be required
23 to determine that.
24 So if they propagate above and below this -- this
25 mid-B1 level, then I would suggest that there's
26 evidence that they do -- or they do display as -- as

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1 faults or fractures. As an example -- sorry, the
2 document is -- yeah. In -- in the second-last sentence
3 there, I talk about having to look above and below.
4 So the McMurray is, you know, laterally, quite --
5 like, it changes quite a bit laterally, and so the
6 seismic signature could change. It could be a facies
7 change within -- within the McMurray that causes these
8 things, but I believe that we'd have to look above and
9 below to -- to -- can we just go back to the semblance
10 slice?
11 THE CHAIR: So, Tammy, again, that was
12 86.02, page 21.
13 A MR. VERMEULEN: Now, that -- to just go back
14 slightly to an example that Mr. Zaitlin had brought up
15 with the cross section, if you look between wells 06-01
16 and 07-01 in -- within the KN06 drainage box, you can
17 see that there is a discontinuity within this semblance
18 slice at that level. Now, what I'm suggesting is we
19 would need to go down within the section to see if that
20 continues lower down in through the McMurray.
21 Q Okay.
22 A So for me, there's not enough evidence with just the
23 single slice to say that it is faults or fractures but
24 that there would need to be more analysis needed.
25 Q Okay. Thank you.
26 But it could be -- an alternative is a facies

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1 change in the McMurray?
2 A Yes.
3 Q Did I --
4 A Yes.
5 Q Okay.
6 A It could be a number of things, yeah.
7 THE CHAIR: So I'm just checking -- I
8 think those are all of my questions. So where do we go
9 here?
10 Ms. Berg, do you have any redirect for your panel?
11 Or maybe should -- maybe what we should do, actually,
12 'cause I'm looking at the time, is take a break now and
13 then come back and do redirect. Would that -- or would
14 you prefer to do it now?
15 MS. BERG: I'm -- I'm -- I do have just a
16 few questions on redirect, and if I could -- I'm
17 hopeful it'll just be about five minutes.
18 THE CHAIR: So let me just check with the
19 court reporter. Are you okay to go another five, ten
20 minutes?
21 THE COURT REPORTER: I'm okay. Thank you.
22 MS. BERG: Thank you very much.
23 I just would really like to speak to my witnesses
24 over the break as we have now got CNRL's opening, and
25 so it -- it would be nice to be open to doing that. So
26 just a few questions.

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Ms. Berg Re-examines ISH Energy Ltd.
Q MS. BERG: Mr. Leech, I'd like to start with you, if you could unmute your microphone.
A MR. LEECH: There we go. Are we on?
Q You are.
Now, Mr. Leech, you were asked about your report yesterday, and I think that you noted that there were things in your report that you were very confident in, and there were things where you said that things were more ambiguous. And for the benefit of the record, I believe that that is page 120 of the transcript.
Could you please go to your report and outline those things that you have a high level of confidence in.
A Sure.
I -- we have a high level of confidence that the 10-01 well is the flowing well, but we have -- it's ambiguous as to where it is flowing to at this point in time. We have a couple of theories that we can bat around, but we have no proof of any of those -- no definitive proof yet of any of those.
Q And could you expand a bit on why you are so confident that 10-01 is the flowing well?
A Yeah. Sure.
It really boils down to one particular event. We can see that, you know, the -- the -- from the downhole

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gauge at 10-01, it's very clear that the well has been flowing. The fact that it's flowing -- that we determined that it's flowing at the 10-01 well rather than being produced down the GOB maybe from 10-34 was -- one suggestion is -- it's really here on page 61.
Q And, sorry, that's page 61 of --
A I've got 63.01, but, apparently, people have 63.02.
Q Okay. So 63.01, page -- PDF page 61?
A Page 61.
Q All right. And just outline what you see there.
A So we have a plot title, "10-01 GOB Permanent High Sample Frequency", and we can see here that at one point in time, we have a very sudden decrease in pressure. This is a zoom plot of the whole thing. So this is really where we come to have the confidence level that the 10-01 well is flowing. We have a sudden drop in pressure. We have a liquid unloading event, and we can tell that by the increase in -- in temperature of the fluids coming into the well.
This liquid and loading event seems to have caused a hydrate to form. Nondebilitating, the well continued to flow afterwards, but we have this dramatic Joule-Thomson cooling event happening. Now, a Joule-Thomson cooling would have to happen very, very close to our pressure recorder and pressure temperature recorder. We have to measure the temperature at the

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same time. So it has to happen very, very close to our gauge.
So this dramatic cooling event is what gives me high confidence that the 10-01 well is the well that's -- that's flowing, leaking, communicating, something.
Q Thank you very much, Mr. Leech.
Mr. Mathison, I'd like to go to you. Are you there? I don't see --
A MR. MATHISON: Yes.
Q Yeah.
A Yes.
Q Okay. In her questions yesterday, Ms. Jamieson asked you about the A2 mudstone.
A Yes. That's right.
Q And you did begin to speak about the differences between the views of ISH and CNRL, and I'm just wondering if you could elaborate on those differences. And again, for the record, that was page 85 of the transcript.
A All right. If I could use the map of the A2 mudstone, please, which will get the --
Q And if you could just indicate where it is on the record.
A Yes.
Q Can you get it?

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A I'm -- I'm getting -- getting that.
I'll begin my -- so this -- this is our map. It's 63.01. Is that correct?
Q 63.02, I guess.
A 63.02, PDF -- PDF 14, page 14.
Q PDF 14.
A And --
Q Okay.
A So our contour -- and the way we've contoured it -- and I believe we've -- we've been very conservative in the way we've -- we've contoured it. You'll notice that the area that we see as having no A2 mudstone in the northwest corner of the KN06 box is larger than -- larger than what -- what CNRL maps it as.
And I think the issue is that they take the zero contour up to the AC/11-01 well, which is right at the top -- right at the top of the box, just in the LSD11, and whereas we're saying that that contour -- you can't call it -- they -- they put it as zero, zero and put their contours all the way up there, but you can't say that. It's -- it's missing. You don't know where that zero edge is. So it's really just a contouring option and -- and suggesting that, in fact -- in fact, oddly enough, we interpret -- and this is based on core -- that the -- the A2 in the -- in the 12 of -- or the -- the 11-01 well is actually the AA/11-01 well, which is

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1 right in the -- actually -- it's actually AA/12-01.
2 Pardon me. It's right in the -- it's -- it's .07.
3 We've actually given that a higher value than they have
4 given it. I think they gave it a .4. We gave it a .7.
5 And that's based on core data.
6 So we're not -- there -- there's great --
7 actually, most of what -- most of the numbers that
8 we're using are very similar. We're just saying we're
9 even a little bit thicker. We're being a little harder
10 on it than -- than they are in this area. Yet I think
11 that I would argue that that is -- that our contours
12 are a very reasonable interpretation and that we could
13 be missing as much as an LSD in total area of
14 A2 mudstone.
15 Q Thank you very much, Mr. Mathison.
16 Ms. Giry, my final question is for you. And are
17 you there? I can't --
18 A MS. GIRY: I am here.
19 Q Okay. Good.
20 So, Ms. Giry, there were a series of questions
21 asked about the 10-01 yesterday that seemed to suggest
22 that ISH was deliberately flowing gas from the 10-01
23 and shut it down on January 7th. I would appreciate if
24 you could comment on that.
25 A Based on all the information that I have had, none of
26 the GOB wells are producing to surface. 10-01 is

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1 flowing, leaking, communicating to somewhere. That's
2 what we have as information and -- and interpretation.
3 Q Okay. Thank you, Ms. Giry.
4 MS. BERG: And those are all my
5 questions, and thank you very much, Madam Chair and
6 court reporter, for indulging me so that I can now talk
7 to my whole panel.
8 And I'd also like to thank you, Madam Chair, for
9 letting me speak to the back-row support last night.
10 We -- just for the record, the only thing we talked
11 about was cutting down the -- the -- the very large set
12 of cross that we had, and we didn't venture into any
13 further questions, which I -- I think we'll be busy
14 with over the next few hours. So, again, I thank you
15 for that.
16 THE CHAIR: Thank you, Ms. Berg.
17 So, ISH panel, both the direct witnesses and
18 support, you are -- I always hate this word, but we use
19 it. You are dismissed. You are no longer on duty, and
20 we will now --
21 MS. TURNER: Madam Chair?
22 THE CHAIR: Yes.
23 MS. TURNER: Can you just pause for a
24 minute.
25 THE CHAIR: Sure.
26 MS. TURNER: We lost JoAnn.

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1 THE CHAIR: We lost JoAnn? Oh, dear.
2 That's not good.
3 MS. JAMIESON: Yes. It's JoAnn. I haven't
4 lost audio, so I've been following everything along,
5 and I'm just kicking back into Zoom, and it looks like
6 it's going to let me back in for the visual.
7 MS. TURNER: So you didn't miss any audio,
8 then?
9 MS. JAMIESON: I did not. Thank you.
10 THE CHAIR: I figured. You're showing up
11 on our screen as a green icon.
12 MS. JAMIESON: I see that. Yeah. I just --
13 THE CHAIR: So we are going to take the
14 morning break now. It's scheduled for half an hour,
15 so -- there you are. So we will reconvene at 11:20 to
16 continue, I think. Next up, then, will be Canadian
17 Natural's direct evidence. And an hour and a half is
18 still what you're --
19 MS. JAMIESON: Yes. That's what we've
20 planned for, and we will endeavour to finish either
21 before or at that time.
22 THE CHAIR: So I'm just thinking. If
23 we're back at 11:20, that makes a late lunch. Does
24 that work for people? Should we try and -- there are
25 options. We can either break the direct if there's a
26 convenient point. If you're going to be giving -- if

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1 you're going to have different people give different
2 portions of your direct, would there be a point that
3 would work for a break?
4 MS. JAMIESON: Yes, I think there potentially
5 is because we have organized the presentation by
6 hearing issue, so if you'd like to track that, we could
7 potentially take a break after the first hearing issue
8 or the second.
9 THE CHAIR: Okay. If that works for you
10 and your witnesses, let's -- we'll just keep an eye on
11 the time, and we'll aim for the second to see if we can
12 get as much done as we can, but if it's looking like
13 we're not going to get there, we'll break after your
14 first hearing issue.
15 MS. JAMIESON: Sure. Okay. Thank you.
16 THE CHAIR: So half an hour. Thank you.
17 MS. TURNER: Madam Chair?
18 THE CHAIR: Yes.
19 MS. TURNER: One housekeeping issue.
20 Actually, it's a technological issue we're having. We
21 may have to stop the meeting and rejoin. That kicks --
22 has everybody else leave. Don't wait. Just go back to
23 the meeting invite and rejoin. We're just wanting to
24 make sure we solve that issue before we continue on
25 after the break.
26 THE CHAIR: So should we just all do that

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anyway? Do you want everybody to just leave the meeting and come back in through the invitation?
MS. TURNER: Probably. That's a great idea. Thank you.
THE CHAIR: Okay.
MS. TURNER: Sorry, everybody. I want to make sure -- and we're experiencing some internet instability.
THE CHAIR: I can see that. Okay. Thank you.
MS. TURNER: Thanks.
THE CHAIR: So we are adjourned.
(ADJOURNMENT)
Direct Evidence of Canadian Natural Resources Limited
MS. JAMIESON: I'm going to commence by introducing the panel and just having them indicate what area of evidence they'll be speaking to.
One item to make note of: We prepared the presentation for 90 minutes, and there's a lot of ground -- technical ground to cover. So we're going to do our best and endeavour to keep it within that time slot. What we didn't account for was sort of any delay or lag in, you know, getting to the next slide or any, you know, technical interruptions. So we're going to do our best to cover it in the 90 minutes, and then if there's an issue there, Madam Chair, I'll let you know.

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THE CHAIR: So you are going to speak to it as a slideshow, then?
MS. JAMIESON: Yes, if that's okay. That's our presentation, yes.
So I'll get started, then. Mr. Iannattone -- Mr. Iannattone is the chair of the Canadian Natural panel and is the senior representative. He has a bachelor of science in mechanical engineering and is a professional engineer by trade. He has over 38 years of experience in the oil and gas industry, which includes a very broad and diverse experience within the western Canada and international basin.
Mr. Iannattone, could you please introduce yourself and indicate what area of Canadian Natural's evidence you'll be speaking to.
MR. IANNATTONE: Yes. My name is Gerard Iannattone. I am the VP of exploitation for the Athabasca Oil Sands Region, and I'm the chair of the panel, and I'm also here to speak to policy issues. Thank you.
MS. JAMIESON: Thank you, Mr. Iannattone.
Madam Chair, my hearing -- or, sorry, regulatory support just indicated -- or asked a question about them being sworn in under oath. Should I get through the introductions first and then have the swearing in, or would you prefer to do that now?

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THE CHAIR: As long you remember to do it. I was -- I was assuming because you hadn't done it first, you were going to ask to have them sworn after the introductions.
MS. JAMIESON: Okay. That's what we'll do. Thank you.
Next is Mr. Jason Lavigne. Mr. Lavigne has a master's of science in geology, and he is a professional geologist by trade. He has -- he's a sedimentologist with 22 years with petroleum industry experience on a wide range of reservoir types from around the world and, in particular, the reservoir in the McMurray sands that we've been speaking of in this proceeding.
Mr. Lavigne, can you please introduce yourself and indicate what area of Canadian Natural's evidence you'll be speaking to.
MR. LAVIGNE: Good morning, Madam Chair and Panel members. I'm a district geologist in the thermal exploration team, and I'll be speaking to the first hearing issue of whether there's an effective barrier or top seal overlying the bitumen-bearing McMurray formation and its relative characteristics in the KN06 box.
MS. JAMIESON: Thank you.
Mr. Sverdahl. Mr. Sverdahl is -- has a bachelor

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of science in geophysics and is a professional geophysicist. He will be -- sorry. He's an exploration manager for the Kirby Athabasca thermal asset.
Mr. Sverdahl, can you please introduce yourself and describe what area of Canadian Natural's evidence you'll be speaking to.
MR. SVERDAHL: Good morning. My name is Scott Sverdahl. I am the exploration manager for the Kirby Athabasca district. I will be discussing natural fractures and faults.
MS. JAMIESON: Thank you.
Next we have Dr. Xiang Wang. And Dr. Xiang Wang is -- has a master's of science in structural geology and geochemistry, another master's of science in structural geology and rock mechanics, and a PhD in geology from the University of New South Wales, Australia. And he has over 20 years of experience in multiple sedimentary basins with varied tectonic styles.
Dr. Wang, can you kindly introduce yourself and indicate what area of Canadian Natural's evidence you'll be speaking to.
DR. WANG: Good morning, Madam Chair and the Panel. My name is Xiang Wang. I'm a project geologist working for the original technical

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1 group at CNRL, and I will speak to the fracture
2 analysis based on the interlog and the core.
3 MS. JAMIESON: Thank you, Dr. Wang.
4 Next we have Mr. Peter Thomsen. Mr. Thomsen has a
5 bachelor of science in petroleum engineering and is a
6 professional engineer by trade. He has expertise in
7 thermal recovery processes, exploitation, and reservoir
8 engineering, geomechanics of oil sands, and caprock
9 integrity.
10 Mr. Thomsen, could you please introduce yourself
11 and indicate what area of Canadian Natural's evidence
12 you'll be speaking with -- to.
13 MR. THOMSEN: Yeah. Good morning, Madam
14 Chair and Panel Members. My name is Peter Thomsen.
15 I'm a reservoir engineering manager, but in thermal.
16 Today I'll be speaking to geomechanics related to the
17 sedimentary issue.
18 MS. JAMIESON: Thank you.
19 Next we have Mr. Dale Walters. Mr. Walters has a
20 bachelor of science degree in civil engineering and a
21 master's of science degree in geotechnical engineering.
22 Mr. Walters is an independent consultant but on
23 long-term contract with Canadian Natural.
24 Mr. Walters, can you please identify yourself and
25 indicate what area of Canadian Natural's evidence
26 you'll speak to.

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1 MR. WALTERS: Yes. Good morning. My name
2 is Dale Walters, and I'm a reservoir and geomechanics
3 expert, and I'll be speaking to the geomechanical
4 modeling.
5 MS. JAMIESON: Mr. Craig. Mr. Ryan Craig has
6 a bachelor of science degree in geological engineering.
7 He is a professional engineer and has 19 years'
8 experience in production development and optimization
9 with the focus on SAGD production for the past 11
10 years.
11 Mr. Craig, can you please introduce yourself and
12 indicate what area of evidence you'll speak to.
13 MR. CRAIG: Yes. Good morning. Thanks.
14 My name is Ryan Craig. I'm the production
15 engineering manager with Canadian Natural and
16 responsible for the Kirby North project. I'll be
17 speaking to Hearing Issue Number 3, which is the need
18 for observation wells.
19 MS. JAMIESON: Thank you.
20 And, finally, we have Dr. Thomas Boone, and Mr. --
21 or Dr. Boone has a bachelor of science in civil
22 engineering, a master's of science in structural
23 engineering from the University of Texas, and a PhD in
24 structural engineering from Cornell University. He has
25 over 35 years' experience in oil and gas, including
26 expertise in geomechanics, hydraulic fracturing,

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1 reservoir engineering, numerical simulation, heavy oil
2 recovery processes, thermal recovery processes, pilot
3 design and operation, risk assessment, and reservoir
4 surveillance.
5 Dr. Boone, I have a couple of questions for you.
6 Can you just describe what you were retained to do for
7 Canadian Natural in this proceeding.
8 Oh, I think, Tom, you're muted. Sorry.
9 DR. BOONE: My apologies.
10 Good morning, Madam Chair and Panel Members. My
11 name is Tom Boone, and I've been engaged by CNRL to
12 provide an independent assessment of their
13 geomechanical work in support of KN06 pad and to
14 evaluate the risk associated with fractures that might
15 be induced during the start-up of SAGD wells at KN06.
16 MS. JAMIESON: And did you prepare an expert
17 report in this proceeding?
18 DR. BOONE: Yes, I did.
19 MS. JAMIESON: And can you just confirm that
20 your report was filed as part of Canadian Natural's
21 hearing submission, Exhibit 30.02?
22 DR. BOONE: Yes, it was.
23 MS. JAMIESON: And can you please confirm
24 that you are providing independent, impartial advice
25 and assessment in the proceeding?
26 DR. BOONE: (INDISCERNIBLE - BACKGROUND

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1 NOISE)
2 MS. JAMIESON: Do you adopt --
3 THE COURT REPORTER: Sorry. Sorry to interrupt. I
4 just didn't get Mr. Boone's answer to your last
5 question.
6 THE CHAIR: Yeah. And, sorry, Mr. Boone,
7 before you answer, could I ask anybody who is not
8 speaking to please turn off your mics. I think Mr. --
9 there we go. When you move around and your mic's on,
10 we get external noise. It makes it hard to hear.
11 MS. JAMIESON: I'll just -- you go --
12 DR. BOONE: Sorry.
13 THE CHAIR: Sorry. Carry on, Mr. Boone.
14 DR. BOONE: Sorry. My previous answer
15 was: I have and I will.
16 MS. JAMIESON: And then do you have any
17 errors or corrections to your report that you'd like to
18 make?
19 DR. BOONE: No, I do not.
20 MS. JAMIESON: Thank you, Dr. Boone.
21 Mr. Iannattone, a couple more questions for you.
22 Was the written evidence filed by Canadian Natural in
23 this proceeding, including Dr. Boone's report, prepared
24 under your direction and control?
25 MR. IANNATTONE: Yes, it was.
26 MS. JAMIESON: And do you adopt that written

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1 evidence as the evidence of Canadian Natural?
2 MR. IANNATTONE: Yes, I do.
3 MS. JAMIESON: Do you have any errors -- or
4 corrections to make on the record for that evidence?
5 MR. IANNATTONE: No, I don't.
6 MS. JAMIESON: Thank you. So I'm going to
7 ask Mr. Iannattone to kindly proceed with Canadian
8 Natural's presentation, and if --
9 THE CHAIR: So now I'll pause you. Do you
10 want to have your witnesses sworn?
11 MS. JAMIESON: There you go. Thank you.
12 Yes, if we could please have our witnesses sworn.
13 GERARD IANNATTONE, JASON LAVIGNE, SCOTT SVERDAHL, XIANG
14 WANG, PETER THOMSEN, TOM BOONE, Affirmed
15 RYAN CRAIG, DALE WALTERS, Sworn
16 MR. IANNATTONE: Ms. Turner, could you get the
17 direct evidence PowerPoint on the screen, please.
18 MS. TURNER: Yes. We will do that for you.
19 THE CHAIR: And are we going to be
20 assigning this an exhibit number?
21 MS. TURNER: The -- sorry, Ms. Jamieson?
22 MS. JAMIESON: Yes. We would appreciate an
23 exhibit number, please.
24 THE CHAIR: Any concerns with that,
25 Ms. Berg? Okay. No concerns.
26 MS. TURNER: Exhibit 88.01 is 2020

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1 October 14 Canadian Natural to AER re: cover letter
2 opening statement.
3 EXHIBIT 88.01 - 2020/10/14 Canadian Natural
4 to AER re: Cover letter opening statement
5 MS. TURNER: Exhibit 88.02, what you see on
6 your screen, is 2020/10/14, Canadian Natural to AER
7 re: KN06 hearing direct evidence.
8 EXHIBIT 88.02 - 2020/10/14 Canadian Natural
9 to AER re: KN06 hearing direct evidence
10 MS. JAMIESON: Thank you very much.
11 With that, Mr. Iannattone, if you could get us
12 started. And I think -- I just remind each speaker to
13 indicate a "next slide" to keep it moving and
14 communicate.
15 Is it -- Ms. Turner, are you doing the slides, or
16 is it Mr. Campbell?
17 MS. TURNER: You can say my name. That's
18 fine. It's actually Ms. Shukalkina, but that might be
19 harder to say.
20 MS. JAMIESON: Okay. So, yeah. Fair enough
21 Speakers, if you could just work with Ms. Turner to
22 keep it moving, that would be great. Thank you.
23 MS. HALL: Madam Chair, I apologize for
24 the interruption. I don't believe that Mr. Scrimshaw
25 and Mr. Ollenberger were sworn.
26 THE CHAIR: Oh, that's right. The support

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1 team.
2 MS. HALL: Yeah.
3 THE CHAIR: Thank you. So we do need --
4 they're not -- so, Mr. Vidal, they aren't direct
5 witnesses, but they may be conferring with the
6 witnesses over the course of their evidence, so our
7 plan was to have them sworn as well. So we need to add
8 Mr. Scrimshaw, who's on the screen there in the blue
9 shirt, and Mr. Ollenberger, who's third -- thank you.
10 MARC SCRIMSHAW, DEVIN OLLENBERGER, Affirmed
11 THE CHAIR: And I think if you just say --
12 whoever is -- when you're giving your portion of the
13 evidence, if you just say "next slide, please,"
14 whoever's doing the slideshow will pick up on that and
15 move to the next slide.
16 MR. IANNATTONE: Okay. All right. Good
17 afternoon, Madam Chair and Panel Members. My name is
18 Gerard Iannattone. I would like to thank the Panel for
19 the opportunity to present our direct evidence.
20 Next slide, please.
21 Canadian Natural has proven execution excellence
22 in developing oil sands using SAGD methods with over 20
23 years of experience. Execution excellence is a core
24 value for us. It describes executing projects by doing
25 it right, safely, efficiently, and effectively.
26 We have a broad space of SAGD experience in many

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1 different geological formations, including the
2 McMurray, Clearwater, and Grand Rapids reservoirs in
3 Alberta and the Lloydminster and Dina reservoirs in
4 Saskatchewan. As part of this vast experience, we have
5 safely started up and operated over 300 SAGD well pairs
6 to date at our SAGD projects listed on this slide.
7 Highly experienced, technical, and operational
8 staff have proven Canadian Natural to be a safe SAGD
9 operator with no incidents of lost steam to other
10 formations during circulation start-ups or continuous
11 SAGD operations.
12 Next slide, please.
13 The Kirby North project application was submitted
14 in December 2011 and approved in May 2014. In
15 May 2018, well over two years ago, Canadian Natural
16 applied to amend, under Directive 78, our SAGD scheme
17 for the inclusion of the KN06 drainage box for the
18 recovery of crude bitumen limited to the McMurray
19 formation. Approval was issued in January of 2019. In
20 February 2020, the AER granted the regulatory appeal to
21 ISH. Canadian Natural respectfully recognizes ISH's
22 concerns and is here to present evidence to address
23 their concerns and the hearing issues.
24 Next slide, please.
25 This slide presents a map of the Kirby Upper
26 Mannville II gas pool relative to the KN06 drainage

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box. Canadian Natural holds a 53.75 percent working interest. ISH holds the remaining balance and is the operator of the shut-in wells. The red line represents our interpretation of the gas pool, whereby the solid red line defines the high-certainty boundary where there's good well control and data. The dashed red line represents the possible extent of the pool based on seismic only where there's less certainty. The shut-in gas well 10-01 is located in the northeast corner of the KN06 box.

Next slide, please.

The 2004 and 2005 GOB decision prioritized bitumen development due to the potential impact on bitumen recovery from the pressure-depleting effect of producing overlying gas. The decision was ordered -- this decision ordered the shut-in of the Mannville II gas pool.

An implication of this prioritization is reflected in the law in Alberta in that the bitumen may be developed even if production of the bitumen inadvertently results in interference and/or permits wastages of the GOB mineral rights. Irrespective of this law, Canadian Natural recognizes and shares ISH's concerns of ensuring no impact to the jointly owned GOB mineral rights.

We wish to -- we wish to note to the Panel that

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compensation was extended for the impact of the GOB decision. Compensation of approximately $5 million total was provided to ourselves and ISH for the direct impacts caused by the shut-in of this pool.

The reason for this regulatory appeal is notably different. The regulatory appeal is to determine whether there is an effective barrier to contain Canadian Natural's KN06 steaming operation as opposed to a barrier requiring -- required for the pressure-depleting effects from producing a gas pool as was the issue in the GOB decision.

Next slide, please.

Canadian Natural has considered and reviewed all of ISH's evidence, and we have submitted substantial evidence that addresses the three hearing issues. Our evidence confirms confinement strata that are an effective barrier to steam exist. The approved circulation start-up and operations will not hydraulically fracture through the barrier. A SAGD observation well is not required or justified. The existing 10-01 gas well is a suitable monitoring well for the Mannville II gas pool.

I will now ask our witness panel to speak to the merits of Canadian Natural's technical evidence.

Mr. Lavigne, please.

MR. LAVIGNE: Next slide, please. Next

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slide.

Thank you, Mr. Iannattone.

With respect to the first hearing issue, ISH's position focuses largely on the findings of the 2003 regional geological study, the RGS, which relies solely on the Upper McMurray B2 and A2 regional mudstones as providing effective containment of the steam chamber. Since that time, almost two decades of operational experience of SAGD reservoirs has allowed for a more detailed understanding of how steam chambers behave and how the aggregate of mudstone-rich facies serve to effectively halt the vertical growth of the steam chamber.

Throughout its submissions, Canadian Natural has supported these more recent conclusions with temperature and other specialized logs on other similar operating assets and geochemical analysis that demonstrate the lack of fluid communication between sandstone beds in heterolithic strata. ISH refutes this vast data asset, largely on the basis of a 17-year-old guidance that was unable to be underpinned by actual operational data.

Next slide, please.

The RGS provides the basis for understanding the stratigraphic position of reservoirs with respect to the regional marine mudstone units. Note the relative

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positions of the KN06 reservoir in the green circle and the Wabiskaw B gas zone in the red circle. Note also the B2 and A2 mudstones in brown and the Wabiskaw D unit in blue, which -- it locally cuts out the A2 mudstone. While we agree with the broad stratigraphy presented in the RGS, several modifications are important.

The term "McMurray channel" has no utility as it fails to discriminate between several valley fills of different ages. Canadian Natural uses the specific nomenclature of "post B2 incision" to describe the valley in which KN06 exists.

Next slide, please.

This series of schematics depicts the deposition of reservoir units and confining strata at KN06. The depiction starts at Time 1 in the upper left with the deposition of the regional B2 scenes. At Time 2 in the top centre, low-standing conditions cause the incision of the post B2 incised valley. Note the B2 regional sequence is completely removed and does not exist where the valley is present. In their revised stratigraphy, ISH suggests that the McMurray B2 is present on top of the KN06 reservoir. This is not possible. The series of schematics show the deposition of the reservoir and confinement strata. At Time 8, in the bottom centre, the Wabiskaw D erosively removes the A2 mudstone in the

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1 northwest corner of the box shown between the dashed
2 lines. Despite this erosion, the presence of the
3 remaining confinement strata here is clearly apparent.
4 Next slide, please.
5 THE CHAIR: Mr. Lavigne, I'm just going to
6 ask you to slow down just a touch for the court
7 reporter and the rest of us. Thank you.
8 MR. LAVIGNE: Okay. Sorry.
9 This annotated well-log cross section shows the
10 relative positions of the SAGD reservoir and overlying
11 Wabiskaw B gas resource. The relative thicknesses of
12 the confinement strata are apparent and consist of post
13 B2 non-reservoir in brown; the regional B1 sequence,
14 including the mid-B1 mudstone in green; and the A2
15 sequence in red with a thin A2 mudstone at its base.
16 Next slide, please.
17 As we spent much time discussing this figure with
18 Mr. Mathison yesterday, I'll only touch on a few
19 salient points here. The regional stratigraphy has
20 been well-established over vast portions of the basin,
21 as outlined not only in the RGS but in other published
22 literature. Mr. Mathison's well log illustrated in
23 Figure C on the right is from a well approximately
24 58 kilometres north of KN06. The Upper McMurray
25 regional units are nearly identical to those in a
26 regional well near the KN06 box. It clearly

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1 illustrates not only the remarkable consistency of the
2 regional units over large areas but also the error in
3 ISH's correlations at KN06. Having B2 deposits above
4 the post B2 incision is not possible. This is not a
5 minor terminological discrepancy. It demonstrates
6 ISH's fundamental lack of understanding of the
7 stratigraphic position of the KN06 reservoir and its
8 relationship to the adjacent strata.
9 ISH's use of McMurray B2 is incorrect, and it's
10 confusing and is not equivalent to the regional B2 map
11 throughout the area away from the KN06 box. This is
12 significant because it calls into question ISH's
13 ability to accurately identify and characterize the
14 confinement strata that provides steam-chamber
15 containment.
16 Next slide, please.
17 Canadian Natural has provided analytical evidence
18 that demonstrates the presence of barriers in package
19 of -- packages of mudstone-rich facies that may provide
20 effective containment of the steam chamber. Together,
21 these units stop the rise of the chamber and do not
22 rely on single, thick, and continuous mudstone units to
23 provide containment. This is understood by studying
24 data from producing assets and is a departure from the
25 findings of the 2003 RGS.
26 While ISH contends that the lack of a regional --

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1 the lack of regional extent of individual mudstone beds
2 in these units make them ineffective barriers,
3 operational data shows that steam-chamber growth is
4 abruptly halted by encountering heterolithic units with
5 low vertical permeability. As we have submitted, steam
6 chambers are being constrained by geological facies,
7 grading upwards to poorer reservoir quality rather than
8 being constrained by shallower, regionally extensive,
9 massive, low-permeability barriers. This phenomenon is
10 well-known to SAGD operators who carefully monitor the
11 ratio of the volume of steam injected to the amount of
12 oil produced to determine the economic threshold for
13 SAGD development.
14 Noneconomic reservoirs are deemed so because they
15 commonly display low vertical permeability that
16 effectively halts the vertical rise of the steam
17 chamber. Canadian Natural defines three packages of
18 strata that will serve to isolate the steam chamber
19 above the KN06 box.
20 Next slide, please.
21 This typical well log from the KN06 box
22 illustrates the confining strata recognized by Canadian
23 Natural. The lower-grade box consists of the post B2
24 non-reservoir; the regional B1 sequence with the mid-B1
25 mudstone, in particular; and the regional A2 mudstone.
26 At KN06, erosion by the overlying Wabiskaw D has

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1 removed parts of the A2 regional sequence in the
2 northwest corner of the pad and -- sorry. And in the
3 northwest corner of the pad, the A2 mudstone has been
4 completely removed. Although there remains a small
5 discrepancy in the extent of the A2 mudstone removal,
6 ISH and Canadian Natural agree that this erosion has
7 occurred. As the ability of the A2 mudstone to act as
8 a barrier to steam where present is not in question, we
9 will briefly discuss the other two confinement strata
10 units and describe their relative characteristics in
11 the KN06 box.
12 Next slide, please.
13 The post B2 non-reservoir. These point bar
14 deposits consist of the mix to mudstone-dominated
15 inclined heterolithic strata. These individual
16 mudstone beds are decimetres thick and typically dip at
17 about 6 to 8 degrees. They are within the upper
18 portion of the muddying upwards sequence that caps the
19 entire post B2 reservoir unit within the post B2
20 incised valley. In the lower sandstone-rich points of
21 the point bar, the lateral extent of individual mud
22 beds may be reduced by erosion, and steam is able to
23 pass laterally around these beds. It will be connected
24 to the steam chamber and is therefore considered
25 reservoir. But as the mudstone content increases
26 upwards, the uppermost portions of the bar have more

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1 laterally continuous and thicker mudstone beds. Steam
2 encounters these mudstone interfaces, and the pressure
3 of the rising steam chamber is insufficient to overcome
4 the high-capillary entrance pressures required for
5 steam to penetrate these beds. Condensation occurs,
6 resulting in a drop in both temperature and pressure.
7 This defines the base of the post B2 non-reservoir
8 unit, the base of the confinement strata. The RGS did
9 not consider these mudstones capable of confining the
10 steam chamber because they could not be correlated
11 regionally. However, over the scale of an individual
12 drainage box within the post B2 incised valley fill,
13 this unit is continuous across the top of the
14 reservoir. This is how Canadian Natural defines the
15 top of the reservoir. It is supported by temperature
16 data from our operating assets in the same incised
17 valley system, which contain analogous confinement
18 strata.
19 Next slide, please.
20 The B1 regional sequence consists of two tidal
21 flat pair sequences separated by the regional flooding
22 surface of the mid-B1 mudstone. The individual pair
23 sequences are variable and comprised of heterolithic
24 facies. In wells such as the 12-01 discussed in ISH's
25 reply submission, their poor choice of stratographic
26 datum has contributed to their miscorrelation of

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1 mudstone units in the B1 regional sequence and the
2 mid-B1 mudstone, in particular. The RGS did not
3 consider this unit as capable of providing steam
4 chamber containment because of the heterolithic nature
5 of the facies. While every individual mud bed may not
6 have large lateral extent, as a whole, the package can
7 be correlated across the entire box. Canadian
8 Natural's subdivision of the B1 regional sequence helps
9 to demonstrate this.
10 ISH has maintained that the presence of thin
11 bituminous sandstones within this unit proves that it
12 cannot serve as an effective barrier to steam.
13 Canadian Natural contends that the disconnected nature
14 of the sandstones and the abundance of mudstone
15 interbeds inhibit the steam chamber's ability to rise
16 vertically through such units. Two decades of
17 operational experience has shown that theoretical
18 vertical pathways relying on spill points around
19 discontinuous, individual mudstone beds in muddy
20 heterolithic facies are not sufficient to enable the
21 steam chamber to rise.
22 Next slide, please.
23 We concur with ISH's acknowledgement in its reply
24 submission that the mid-B1 mudstone has characteristics
25 similar to the A2 mudstone, which is a recognized
26 regional seal. In the map in the upper right, ISH

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1 interpreted a long linear area across the pad where the
2 mid-B1 mudstone has been removed. We disagree with
3 this interpretation. An examination of the 1AA/06-01
4 well from this area shows that the mid-B1 flooding
5 surface is present. This is shown in a red circle in
6 the bottom centre diagram.
7 The upper B1 in this well is a mudstone-rich pair
8 sequence. The mudstone-prone nature of this region ISH
9 identifies is because of the lithological variability
10 in the upper B1 unit and not because the mid-B1
11 mudstone has been cut out. Canadian Natural contends
12 that the mid-B1 mudstone is present across the entire
13 KN06 box.
14 Next slide, please.
15 In summary, there are between 9.7 and 15.3 metres
16 of confinement strata over the entire KN06 box. The
17 mudstone-rich nature of the confining strata is clearly
18 visible in the core photo at the bottom of the slide.
19 Next slide, please.
20 Canadian Natural has submitted gas
21 chromatography-mass spectometry, or GCMS, data to
22 support the presence of vertical barriers to steam. As
23 microbes do create oil accumulations, distinct ratios
24 of specific chemical compounds within connected oil
25 columns are produced. GCMS analysis examines these
26 ratios that determines the existence of barriers to

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1 fluid communication between different units. The
2 barriers that allowed these units to degrade in
3 hydrostatic isolation from one another may also prevent
4 steam from rising through them.
5 The bottom left image from Adams, et al.
6 schematically shows changes in the signatures, which
7 also correlate to known viscosity gradients and can be
8 interpreted to provide evidence of barriers and
9 baffles.
10 The plot in the upper right shows the GCMS data
11 plotted from the AA/11-01 well in the KN06 box. Each
12 analyzed sample is represented by a blue diamond.
13 Starting at the lower left of the chart, the diamonds
14 stack vertically on top of one another in the connected
15 hydrocarbon column of the post B2 reservoir. At about
16 477 metres, there is a dramatic step change to the
17 left, signifying a barrier within the reservoir unit,
18 the black circle on the chart and on the log at the
19 left. At 470 metres, there is a significant
20 back-stepping in the concentrations corresponding to
21 the base of the post B2 non-reservoir in grey. Another
22 major step change corresponds to the base of the mid-B1
23 mudstone at about 461 metres in green. A further
24 back-stepping change is also observed across the
25 A2 mudstone at about 456 metres in the red circle.
26 Each of the confinement strata defined by Canadian

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Natural has a corresponding GCMS break. This is supportive of the ability of these mudstone units to provide vertical barriers to steam chamber growth.

Next slide, please.

Reservoir saturation tool logs, or RST, are used to evaluate the position of the steam chambers in SAGD reservoirs. This Schlumberger tool measures carbon and oxygen concentrations at various times during the life of a SAGD operation to show reservoir depletion. Temperature logs confirm the position of the top of the steam chamber at about 200 degrees C. In this illustrated example from Jackfish, the steam chamber can be shown to be stopped at a mudstone at the dark black line near the lower right of the log. This mudstone occurs within the post B2 reservoir.

Much like the KN06 example previously illustrated, the steam chamber is held up even lower than the base of the post B2 non-reservoir throughout the life cycle of the well pairs. It has not even reached the base of the confinement strata, let alone risen through it. As shown at Time 2, conductive heating occurs above the steam chamber top but at temperatures less than that of the active steam chamber.

Canadian Natural has used the learnings of this tool in similar post BT incision reservoirs with the same confinement strata to show containment of the

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steam chamber over the life of the SAGD operation. The absence of the A2 mudstone in a small corner of the KN06 pad is of lesser consequence when empirical data from similar deposits show that the steam chamber is contained much lower in the stratigraphy.

Next slide, please.

In summary, high capillary entrance pressures inhibit steam from penetrating silty mudstone interbeds regardless of the environment of deposition. Within sandstone-dominated facies, individual dipping or discontinuous mudstone interbeds may allow for steam to bypass them laterally. However, in mixed-percentage facies, the cumulative effect of many small, discontinuous mudstone beds is to halt the vertical rise of steam. This is not merely conjecture. There is a wealth of operational data that supports this conclusion. Reserve calculations and production-type curve projections are based on the knowledge of this phenomena.

ISH is incorrect in its assumptions that the presence of bitumen in the heterolithic deposits of the non-reservoir units compromises the entire unit's capability to contain the steam chamber. Temperature logs demonstrate that these individual sandstones are isolated from the steam chamber. While the RGS focused exclusively on thick, regionally extensive mudstones to

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provide containment in the steam chambers, nearly two decades of operational experience has shown that containment of steam occurs much lower in the stratographic column. The RGS was very conservative, and deeper heterolithic facies at the top of the reservoir stop the vertical growth of the steam chamber well below the regional A2 mudstone.

Next slide, please.

ISH has raised the concern that natural fractures may compromise the effectiveness of the confinement strata. In their reply submission, they illustrate interpreted fractures in two cores that are outside the KN06 box. Many of these fractures appear to be induced from the coring process.

On the left, centreline fractures wander from side to side down the middle of the core. Petal fractures are curved and propagate downwards towards the centre of the core where they may join the centreline fractures. In contrast, natural fractures on the right are plainer and usually intersect the entire core.

Next slide, please.

While a low density of natural fractures may be seen in the Wabiskaw B, the fractures that had been identified by ISH in the confinement strata appear to be drilling induced. The right-hand most fracture is in a siderite cemented portion of the upper B1 and

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displays a classical petal centreline induced fracture morphology.

The vertical cracking labelled left of centre in the photo is commonly observed due to the degassing of core on retrieval from depth. The PVC2 that the core is recovered in has holes specifically drilled in it to minimize this commonly observed phenomenon.

The farthest left feature labelled in the photo is a petal fracture that terminates near the centre of the core suggesting it is induced.

Next slide, please.

These fractures that ISH has identified in the mid-B Mudstone are similarly induced. The horizontal partings occur as core is brought to the surface and lithostatic pressure is released. The high-angle fracture at the lowest arrow offsets one of these partings suggesting that it formed after this unloading. None of these fractures has a clean, plainer morphology indicative of a natural fracture.

Next slide, please.

As we saw yesterday in their direct evidence submission in the 1AA/02-1, which is off the KN06 pad, ISH has identified these two features as fractures. It appears Canadian Natural had some of the same concerns as Mr. Poitras.

The first in the McMurray C unit is a desiccation

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1 crack passively filled by sand from above. The
2 contortion of the bedding and siderite nodule suggest
3 wetting and drying of the sediment during deposition,
4 not fracturing.
5 The second is a conjugate set of induced fractures
6 that happened as the bit cut through the white-ish
7 calcite region labelled. The water sand below was
8 partially washed out of the core barrel, and the
9 voidage was filled with drilling mud.
10 Next slide, please.
11 Also from the 1AA/02-01 well, off pad, ISH
12 presented these fractures in the post B2 non-reservoir
13 channel abandonment facies. The first is a small
14 breccia of deformed mudstone clasts. The second is a
15 route trace easily identified by its organic walls.
16 The third feature is a small gutter cast from
17 small-scale erosion, not fracturing. The fourth
18 feature is from the lower B1 sequence. It is not a
19 fracture but a skolithos burrow that crosscuts the
20 high-density, monospecific cylindricus assemblage
21 typical of the B1 unit.
22 I might add, though it is not figured here, as
23 discussed this morning, paragraph 48 of ISH's opening
24 remarks, Mr. Mathison has misidentified a swarm of
25 fractures in the Wab C. This is actually a burrow
26 referred to as Diplocraterion habichii. It is a very

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1 common trace fossil seen in cores and outcrop.
2 Mr. Mathison's fractures are the edges of the shaft of
3 the U-shaped burrow that have disrupted the mud beds
4 that have been burrowed through.
5 In summary, while ISH is -- has tried to
6 demonstrate that a high density of fractures exist in
7 core photos from several wells outside the KN06 box,
8 there is little convincing evidence that any of these
9 are natural fractures. A low-density suite of natural
10 fractures likely do exist in many of the units, but ISH
11 has failed to convincingly demonstrate that there is a
12 pervasive network of natural fractures that is
13 indicative of faulting or that poses any risk to the
14 sealing capacity of the confinement strata. Fractures
15 are not seen in the confinement strata in the 20
16 image -- image logs that Canadian Natural has provided,
17 suggesting that even if a low-density suite of natural
18 fractures exist, they are closed at depth and incapable
19 of being conduits for steam.
20 I will now hand over to my colleague Mr. Sverdahl
21 who will discuss the 3D seismic analysis as it speaks
22 to any evidence of faulting in the KN06 region.
23 THE CHAIR: So, Ms. Jamieson, would this
24 be an appropriate point to take the midday break?
25 MS. JAMIESON: Yes. Thanks, Madam Chair.
26 Actually, we have about five more slides, and that

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1 would sort of finish off the geology and -- and seismic
2 evidence, if we could see those through, and then I
3 think it would be a great time.
4 THE CHAIR: Okay. Let's proceed, then.
5 Thank you.
6 MR. SVERDAHL: Thank you, Mr. Lavigne.
7 Today I'm going to speak to Canadian Natural's
8 position that there's no evidence of pre-existing
9 faults within the containment barrier, and there is a
10 low intensity of natural crashing at KN06.
11 Next slide, please. Next slide, please.
12 Firstly, faults. Salt dissolution and/or large
13 faulting is not present at KN06, which has been agreed
14 to by ISH. Structural variations at KN06 is a result
15 of differential compaction of the post B2 reservoir
16 sand, including structural drape over pre-existing
17 Paleozoic high. There is no evidence of faulting
18 within the confinement strata on Canadian Natural's
19 seismic data or seismically derived maps.
20 Next slide, please.
21 First, I'd like to start with a brief overview to
22 contrast the concepts of differential compaction versus
23 faulting. The top two schematics show the results of
24 differential compaction processes known to be occurring
25 in the KN06 area. Muds and silts deposited adjacent to
26 a feature such as inside valleys filled with sand or

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1 sediment deposited over a pre-existing topographic
2 feature such as a carbonate Paleozoic high will compact
3 significantly more due to their high compressibility
4 when pressure is increased from burial of additional
5 overlying sediment. Muds and silts can compact up to
6 two times that of sand; therefore, structural drape
7 caused by thick McMurray post B2 incision sand adjacent
8 to muds and silts can be significant.
9 The bottom figure shows an example schematic of a
10 normal fault. Faults can be described as a planar
11 fracture or discontinuity in a volume of rock across
12 which there has been significant displacement as a
13 result of rock-mass movement. This displacement will
14 show up as a distinct break in continuity along seismic
15 reflectors for offsets above seismic resolution.
16 Next slide, please.
17 The Wabiskaw B structure map on the right of this
18 slide clearly shows an east-west trending structural
19 high, which is similarly on trend with the most
20 sandwiched portions of the underlying post B2
21 McMurray SAGD reservoir, i.e., where the KN06 drainage
22 box is placed. The seismic section on the left also
23 shows a distinct but gradual structural decrease from
24 north to south where post B2 reservoir sands are very
25 thick in the north and are poorly developed in the
26 south. This structure change is primarily a result of

1 differential compaction.
2 Finally, it is noted that there are no sharp
3 breaks or discontinuities that exist at or near the
4 confinement strata interval which could be interpreted
5 as faulting.
6 Next slide.
7 Compaction traits effects due to differential
8 erosion at the Paleozoic unconformity are observed on
9 the east-west seismic section on the left. A relative
10 high exists in the west, and a relative low exists to
11 the east due to relatively -- relative thinning and
12 thickening of the Moberly to Paleozoic interval. This
13 is highlighted by the arrows. Geological horizons
14 above the Paleozoic are seen to drape over the top of
15 this pre-existing structural feature. Again, it is
16 noted that there are no sharp breaks or discontinuity
17 that could interpret it as faulting within the
18 confinement strata or at any level on this
19 representative seismic line.
20 The next slide, please.
21 This slide shows an image of a semblance slice
22 calculated from the 3D data set, approximately the B --
23 approximately at the mid-B1 mudstone level on the
24 prestacked time at various volumes. Semblance is a
25 seismic attribute used to show seismic trace-to-trace
26 continuity at stratigraphic levels in the subsurface.

1 Geologic features such as faults can have a low
2 continuity across the trace of a fault. It would be
3 expected that faults with offsets postulated by ISH in
4 the order of 7 metres within the confinement strata
5 would be clearly visible at linear discontinuities on
6 the semblance slice. However, no faulting is observed.
7 Smaller-scale faulting near the detection limits
8 of seismic resolution can sometimes be observed as less
9 prominent discontinuities on semblance slicing.
10 However, again, no such features are observed on the
11 slice within the KN06 drainage box. Subtle north-south
12 and east-west lineaments are likely related to
13 acquisition footprint. It may be observed on
14 this section, though.
15 Next slide.
16 THE CHAIR: For the court reporter's sake,
17 Mr. Sverdahl, sorry, just a tad slower, please.
18 MR. SVERDAHL: Yes. No problem.
19 All right. It is Canadian Natural's position that
20 the intensity of natural fractures at KN06 is low.
21 This is supported by analysis of a large data set of
22 both image logs and as well as the previously discussed
23 core photos at KN06, neither of which have shown
24 evidence of natural fractures or faults within
25 confinement strata.
26 Next slide.

1 CNRL conducted a review of 20 image logs at KN06
2 shown at the map in the top right. From these image
3 logs, no fractures were observed within the confinement
4 strata, and only one fracture was observed at all
5 between the Wabiskaw B and Paleozoic interval. The
6 1AA/07-01 well shows this fracture to occur within the
7 lowermost McMurray, which is below both the confinement
8 strata and the SAGD reservoir zone and is not a concern
9 for a potential breach to the confinement strata.
10 These observations from the 20 image logs show
11 that the fracture intensity at KN06 is low and
12 therefore highly unlikely that an open, connected,
13 natural fracture networks exists at KN06 that would
14 provide a potential pathway for steam to the
15 confinement strata and into the GOB zone.
16 Next slide, please.
17 In conclusion, large-scale faulting and/or salt
18 dissolution does not exist at KN06. Differential
19 compaction of the McMurray post B2 incision reservoir
20 sand coupled with compaction drape effects over
21 pre-existing Paleozoic high is the cause of structural
22 variation observed at KN06.
23 There are no additional indications of faulting
24 within the confinement strata on Canadian Natural
25 seismic data or seismically derived maps. Image-log
26 data confirm that the intensity of natural fracturing

1 is low at KN06 with no natural fractures observed
2 within the confinement strata interval.
3 Thank you for the time. And after the break, I
4 will turn it over to Mr. Thomsen to discuss the
5 geomechanics of containment barrier at KN06. Thank
6 you.
7 MS. JAMIESON: This would be a good time now,
8 Madam Chair.
9 THE CHAIR: Okay. Thank you,
10 Mr. Sverdahl, and thank you, Ms. Jamieson.
11 So we will take the midday break. Let's plan to
12 reconvene at 1:20. Just for -- for general
13 information, we do have quite a bit of room in the
14 schedule tomorrow afternoon. So to the extent that we
15 don't finish today what's on the originally circulated
16 schedule, I don't anticipate that causing problems
17 because we do have room to move into tomorrow
18 afternoon.
19 So with that, we will adjourn. And just a
20 reminder to the Canadian Natural witness panel that you
21 can speak among yourselves but not with your counsel
22 and not with anybody who is not sworn with you for this
23 panel.
24 Okay. So we'll see you all back here at 1:20.
25 Thank you.
26 _____

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PROCEEDINGS ADJOURNED UNTIL 1:20 PM

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Proceedings taken Via Remote Video

October 14, 2020 Afternoon Session

C. Low The Chair
C. McKinnon Hearing Commissioner
B. Zaitlin Hearing Commissioner

S. Poitras AER Counsel
A. Hall AER Counsel
D. Campbell AER Staff
E. McKellar AER Staff
S. Botterill AER Staff
E. Galloway AER Staff
T. Turner AER Staff
A. Shukalkina AER Staff

L. Berg For ISH Energy Ltd.
S. Hryciw

J. Jamieson For Canadian Natural Resources Limited

S. Howden, CSR(A) Official Court Reporter
A. Vidal, CSR(A) Official Court Reporter

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(PROCEEDINGS COMMENCED AT 1:20 PM)
THE CHAIR: So good afternoon again, everyone.
Ms. Jamieson, is your witness panel ready to proceed? I think we were going into geomechanics with Mr. Thomsen.
MS. JAMIESON: Yes, Madam Chair. I see everybody is here and accounted for, and I would ask Mr. Thomsen to get started where we left off. Thank you.
Direct Evidence of Canadian Natural Resources Limited
MR. THOMSEN: Good afternoon, Madam Chair and Panel Members.
Thank you, Mr. Sverdahl, for explaining the geophysics evidence and showing there's no seismic-scale falling in the confinement strata and that the natural fracture intensity is low.
In addition to the evidence presented so far, it is important to consider that significant pressure difference that has been maintained between the GOB and the McMurray bottom water. Since the GOB production was shut in in 2005, an upward pressure difference of greater than 1 MPa has been maintained due to the effective -- effectiveness of the confinement strata as a barrier. This is inconsistent with the ISH claim of natural fracture and fault open conduits or, should we

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say, a phantom risk.
Next slide, please.
Next, we shall present the geomechanics evaluation which addresses the second hearing issue. It will show that likelihood of fracture to the confinement strata is extremely low. The KN06 geomechanics evaluation will demonstrate that the confinement strata will contain steam and reservoir fluids within the McMurray formation.
Next side, please.
The KN06 start-up plan was created based upon field experience from Kirby South and Kirby North. In order to assess the risk of fracturing within the post B2 reservoir sand, never mind the risk of fracturing the overlying confinement strata, we must begin with the existing field data. Any geomechanic's evaluation about the risk of fracturing must honour representative field data. In Kirby North, 96 horizontal wells started steam circulation in 2019. These wells were assessed for indications of hydraulic fracturing. 95 out of the 96 wells conclusively initiated circulation without hydraulic fracturing of the sand.
The risk of fracturing the post B2 reservoir sand is low, and without initiating a hydraulic fracture within the sand, the risk of fracturing through the confinement strata is even lower. When bottomhole

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1 pressures greater than 6 MPa were used, it was for
2 short timeframes, typically one hour, and small volumes
3 of steam were injected, typically between 1 to 3 cubic
4 metres per well.
5 The KN06 approved pressures is consistent with
6 commercial field experience in Kirby.
7 Next slide, please.
8 This is an illustration of a circulation start-up
9 and represents the 95 of the 96 existing Kirby North
10 wells. There is no indication of hydraulic fracturing.
11 Shown as a graph of pressure of steam rate and a lith
12 gas rate versus time. Lith gas injections starts with
13 a yellow line increasing from zero. Coinciding with
14 the black line, the bottomhole pressure begins to
15 increase at a faster rate. This results in the liquid
16 being unloaded from the wellbore as circulation
17 initiates, which corresponds with a large decrease in
18 the bottomhole pressure. The key message is that the
19 use of bottomhole pressures above 6 MPa and up to 7 MPa
20 is for short periods of time, typically one hour or
21 less.
22 Next slide, please.
23 Next we will cover in situ stresses and fracture
24 containment mechanisms. First, hydraulic fractures
25 open against the minimum stress, which can be thought
26 of as the path of least resistance. Within KN06, the

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1 minimum stress has been minimum horizontal in situ
2 stress, and a potential hydraulic fracture would be
3 oriented vertically.
4 There are three fracture containment mechanisms
5 present within the KN06 McMurray formation, and these
6 are, Number 1, leak off of water flowing away from the
7 fracture through porous media; Number 2, a stress
8 contrast between lower-stress sand and higher-stress
9 mudstones; and Number 3, a Poroelastic stress increase,
10 which requires progressively higher pressures to
11 continue fracturing at the sand.
12 The rest of my material will focus on evaluating
13 in situ stresses for the purpose of showing stress
14 contact fracture containment mechanisms. Within the
15 McMurray formation setting, stresses and not rock
16 strength are a primary control of hydraulic fracture
17 behaviour.
18 Next slide, please.
19 Within the subsurface, stresses cannot be measured
20 directly. Instead we use diagnostic fracture injection
21 tests, or DFITs, to determine an in situ stress. In
22 the lower figure is an annotated graph of pressure
23 versus time for a DFIT cycle. At Point 2, the pressure
24 stabilizes at a fracture propagation pressure. A
25 fracture is open when the well is shut in, and as the
26 pressure declines, a point will come where the fracture

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1 will close.
2 The pressure at this point is called a fracture
3 closure pressure, the FCP, at Point 4. This is
4 equivalent to a minimum stress acting upon a fracture.
5 DFIT measure pressures consistently show that the
6 fracture propagation of pressures are greater than the
7 fracture closure pressures due to hydraulic fractures
8 requiring an additional pressure above the minimum
9 stress. This additional pressure is referred to as the
10 "net fracture pressure."
11 Next slide, please.
12 The Canadian -- Canadian Natural methodology to
13 analyze DFITs is robust and has previously been used
14 within AER applications. It uses a technical criteria
15 of proximity and a requirement for high-confidence DFIT
16 interpretations. Unfortunately, some acquired DFIT
17 data sets are not conducive to high-confidence
18 interpretations. The DFIT methodology is technically
19 rigorous with a transparent defence in the Canadian
20 Natural written submission, Tab 40. It uses a
21 consistent approach between different DFITs and has the
22 enhanced capacity to review, grade, and compare
23 different DFIT data sets for quality. Finally, a peer
24 review process with three independent experts was used
25 for the assessment of KN06 stresses.
26 Next slide, please.

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1 Applying the stress gradients within the KN06
2 setting results in this stress profile. The graph is
3 showing depth versus stress. For the shallowest KN06
4 well, the minimum stress in the post B2 reservoir sand
5 is 6. -- 6.2 MPa, the lower black dot. Above this, at
6 the base of the mid-B1 mudstone, the minimum stress is
7 6.7 MPa. The critical point from this DFIT evaluation
8 is that there is a high confidence of stress contrast
9 between the post B2 reservoir sand and the mid-B1
10 mudstone. This stress contrast is a fracture
11 containment mechanism or a fracture barrier within the
12 McMurray formation.
13 Next slide, please.
14 In conclusion, for KN06, in situ stresses and not
15 material strength are a primary control of hydraulic
16 fracturing. Additional pressures above the minimum
17 stress, a net fracture pressure, is required to
18 propagate a hydraulic fracture. For KN06, there's a
19 high confidence of a stress contrast between the
20 reservoir sand and the confinement strata. The stress
21 contrast is a significant fracture containment
22 mechanism, and the planned KN06 start-up will not
23 hydraulically fracture through the confinement strata.
24 Next slide, please.
25 The final slide I'm presenting today shows that
26 numerous other operators have been approved for

short-term use of downhole pressures for the purpose of initiating circulation. In addition, the lower half of this table shows three other SAGD operators who have had dilation start-ups approved, which involves leveraging geomechanical behavior of sand to increase permeability. Dilation start-ups involve higher-pressure gradients relative to the KN06 start-up plan. The KN06 start-up plan is a measured approach and should not be considered to be pushing the envelope.

Thank you for your time, and I'll now pass the presentation to Mr. Walters, who will be showing how geomechanical modeling demonstrates that the KN06 start-up is unable to fracture through the confinement strata.

MR. WALTERS: Good afternoon, Madam Chair and Hearing Panel Members.

The next section will discuss the geomechanical modeling and its use for assessing the risk of fracturing through the confinement strata.

Next slide, please.

First, why do we conduct geomechanical modeling? In this context, steam injection into a bitumen reservoir, the typical reason for geomechanical modeling is to assess reservoir fluid containment by evaluating caprock integrity over the life of the

field.

In the case of KN06, we are focused on a shorter time frame of just a start-up period. The geomechanical modeling is used for the same purpose, to assess if injected fluids remain confined below the confinement strata.

The geomechanical model is used both to verify and sensitize the geomechanical mechanisms that impact fluid containment, specifically fracturing.

From a geomechanical modeling perspective, the main objective is to determine if a fracture can initiate at the wellbore and, if so, propagate into the mid-B1 mudstone under approved start-up conditions.

The modeling methodology was based on the use of a commercial software called GEOSIM that is a coupled reservoir and geomechanical simulator. GEOSIM was used to model potential fracture initiation and growth and assess the extent of fracturing. GEOSIM is an AER-recognized geomechanical and reservoir simulator for caprock integrity analysis and, over the past 20-plus years, has become an industry standard in Alberta.

Next side, please.

The modeling methodology was very much focused on fracture initiation and growth. The fracturing prediction is subject to initial and dynamic stress

state, permeability available for leak-off, elastic rock properties, and having an accurate reservoir geometry. In the same manner as typical caprock integrity analyses, a deterministic approach was used with conservative assumptions made where needed to ensure a conservative assessment was made.

Some of these conservative assumptions are as follows: Only the mid-B1 mudstone was investigated as a stress-containment barrier. Low leak-off parameters were used. A constant injection rate over the full approved start-up period of 14 days, given a net injection volume greater than field measurements was used. And only one fracture was assumed to be growing in the model.

Next slide, please.

Next, I will review the geomechanical inputs used in the modeling. The bottom figure shows the 3D grid used for modeling. It is a structured grid with variable thickness in all layers honouring geological mapping. The list to the right of the figure shows the main stratigraphic zones included in the model.

The focus was the well located in the McMurray post B2 SAGD zone and potential fracturing from that well vertically through the confinement strata. The main inputs for this model were the detailed geological description, including reservoir properties such as

porosity, permeability, and initial water saturation, geomechanical material properties, and the most important data for the fracture modeling was the initial stress state. A stress measurement of 13.1 KPa per metre from the McMurray reservoir sand was used to populate all of the McMurray zones from the McMurray base up to the mid-B1 mudstone. A stress measurement of 14.6 KPa per metre was used to populate the stress in the mid-B1 mudstone.

Next slide, please.

This slide presents a schematic to illustrate the problems solved by the modeling and the main mechanisms affecting the growth of a fracture. The simulation model functions as a useful tool to demonstrate these mechanisms and help quantify the conditions for fracture containment.

First, we see a cross-sectional representation of a horizontal well landed in the McMurray post B2 SAGD zone with a vertical fracture initiated at some point along the horizontal length. This fracture contains fluid at a pressure which is referred to as the "fracture pressure." In order for a fracture to open and grow, the fracture pressure must exceed the bounding minimum horizontal stress.

Next, I will discuss the main fracture containment mechanisms present at KN06. The first mechanism is

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leak-off. The permeability of the formation surrounding the fracture allows the fluid to pump into the fracture to leak off and dissipate pressure. The second main containment mechanism is the stress contrast from the sand-dominated post B2 McMurray to the mid-B1 mudstone. It may be observed that a step change in stress occurs as you move from the sand grey stress gradient -- or green stress gradient to the mudstone grey stress gradient. If a fracture were to grow in height to the base of the mid-B1 mudstone, the fracture pressure would not be high enough to continue to grow due to the step increase in minimum horizontal stress. The final containment mechanism is a stress increase due to the pressure increase in the leak-off zone called "poroelastic stress change."

Next slide, please.

In this slide, the fracture growth prediction for the most realistic case is presented. This case is still very conservative, but it includes all three of the fracture containment mechanisms just discussed and so incorporates all of the relevant physics. In my opinion, it represents the best estimate of a conservative case. The figure shows a cross-sectional plot of pressure in the potential fracture plane as it initiates and grows. A well is at the side of the grid and going into the screen and marked by a black circle.

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A constant injection rate representing the highest observed start-up steam rate was used for the full 14-day start-up period.

The bottomhole pressure of the model was not restricted to 7 MPa in order to allow the single-fracture model to grow to maximum dimensions. The plot shows a maximum predicted fracture size of only a few metres with the containment mechanisms of leak-off and poroelastic stress increase controlling the fracture growth.

In more detail, the model shows that after several hours of injection or a time period similar to a lengthy CNRL start-up above fracture pressure, the fracture is less than 1 metre in height. In fact, as shown here, even after 14 days and more than 2,000 metres cubed of injection, the fracture was still less than 5 metres in height and well within the McMurray post B2 SAGD zone.

Also, the fracture pressure increased above the 7 MPa bottomhole pressure limit after only 16 hours of injection or about 100 metres cubed of net injection.

Several other sensitivities specifically focusing on each of the containment mechanisms were also investigated, and all cases showed containment of the fracture below the mid-B1 mudstone. The modeling clearly demonstrates that even for conservative

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estimates of permeability, the leak-off and associated poroelastic stress increase effectively restrict any potential fracture growth to the near wellbore zone.

Next slide, please.

In conclusion, the coupled and reservoir -- the coupled reservoir and geomechanical modeling demonstrated that the risk of fracturing through the confinement strata with a start-up bottomhole pressure up to 7 MPa is extremely low. This is due to three effective containment mechanisms present at KN06: leak-off, poroelastic stress increase, and stress contrast.

Thank you. And now I'll pass it off to Mr. Craig.

MR. CRAIG: All right. Thank you, Mr. Walters.

I'd like to shift to Hearing Issue Number 3 and summarize Canadian Natural's position with respect to observation wells in KN06 and specifically why there's no need for a new observation well.

Next slide, please.

First, there's an extremely low likelihood of contamination of the GOB zone. You've already heard evidence regarding the presence of effective barriers, and you've heard the geomechanics evidence regarding the competency of those barriers. Upgraded start-up procedure will be utilized on KN06 to further reduce

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any likely -- any likelihood of contamination.

Secondly, SAGD observation wells are not intended to monitor the GOB zone. To monitor the GOB, a new well could be modified to collect pressure and temperature data. However, the cost to construct a new well would approach or exceed the value of the gas it's designed to monitor. Observation wells do not provide monitoring -- or, sorry, they do provide monitoring, but they do not prevent contamination of the GOB. The existing surveillance methods used today adequately monitor circulation start-up, and there will be enhancements to these methods for KN06.

In addition to surveillance, the controls used to prevent an overpressure scenario are robust and are demonstrated to be effective during the start-up and ongoing operation of Kirby North. Finally, if GOB monitoring is required, there are alternatives available, and I'll share the facts on the 100/10-01 well and why it's an ideal candidate.

Next slide, please.

We've already heard -- we've heard there's an aggregation of confinement strata, which provide a layered effect, and these strata are free of fractures and provide a barrier to contain steam. We also have high confidence in the ability of this barrier to contain any fractures. There's been rigorous review of

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1 the DFIT and in situ stress measurements, and modeling
2 has been completed using conservative inputs.
3 Using these factors alone, there's an extremely
4 low likelihood of GOB contamination, and this statement
5 is supported by the field evidence, where it's shown
6 that 95 out of the 96 wells were circulated without any
7 indication of hydraulic fracture.
8 The likelihood of impacting the GOB is further
9 reduced by revisions to the existing start-up
10 procedure. Canadian Natural is committed to upgrading
11 its practices and will use revised procedures during
12 the start-up of KN06. This will see gas injection
13 initiated to reduce the fluid density of the liquid
14 column in the well prior to increasing steam rates,
15 and, as a result, a lower bottomhole pressure will lift
16 fluids to surface.
17 The field data concludes there's a likelihood --
18 there is low likelihood of GOB contamination, and
19 upgraded procedures will further reduce the likelihood.
20 Next slide, please.
21 SAGD obs wells are designed to monitor steam
22 chamber growth in the bitumen reservoir, and as shown
23 in the cartoon, typically you're instrumented with
24 instruments piezometers and thermocouples mounted
25 externally to the casing. These instruments monitor
26 pressure and temperature at various zones in the -- in

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1 the bitumen and occasionally the caprock or the bottom
2 water as shown here.
3 A SAGD obs well could be redesigned to monitor the
4 GOB by placing a sensor which is shown in the -- in the
5 red box on the diagram, placing that sensor against
6 the Wab -- against the Wabiskaw interval.
7 The sensor would monitor for pressure and
8 temperature increases; however, any observation -- any
9 observations would not be conclusive evidence of a GOB
10 impact. So, for example, all the temperatures would
11 need to exceed the values expected through temperature
12 conduction, and any pressure responses would not be
13 conclusive because of the expected pore pressure
14 increase due to conductive heating.
15 The cost to drill and equip a well that's
16 been modified for GOB -- for the purposes of GOB
17 monitoring would approach or exceed the value of the
18 gas it's designed to monitor. Shown is a conservative
19 construction cost of $600,000 versus the value of the
20 gas being monitored.
21 Next slide, please.
22 Monitoring the GOB is not required if controls are
23 in place to prevent contamination. And Canadian
24 Natural has demonstrated that through surveillance
25 we're able to effectively monitor start-up in SAGD.
26 Several layers of surveillance are in place -- in

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1 place, including 24/7, seven-day-a-week staffing of a
2 control room on-site, high-frequency data collection to
3 provide realtime monitoring of conditions, and --
4 however, to reduce the likelihood of any impact to the
5 GOB, Canadian Natural will also implement enhanced
6 monitoring of injection rates and pressures during the
7 start-up of KN06.
8 So this enhanced monitoring will see Canadian
9 Natural ensure that there's a team of engineers
10 available to monitor the realtime data trends for any
11 wells that have reached a 6 MPa bottomhole pressure but
12 have not yet unloaded fluid to surface. This team will
13 monitor the well conditions as that bottomhole pressure
14 is then increased up to 7 MPa, and that team remains in
15 place until the well is unloaded and circulations
16 begin.
17 In the highly unlikely event of a fracture, this
18 team will allow for that fracture event to be
19 recognized in realtime and take immediate steps to
20 reduce rates and pressures.
21 Finally, alarms and shutdowns that are currently
22 in place will remain so. During circulation, an
23 audible and visual high alarm is triggered whenever
24 bottomhole pressures reach 6,800 KPa. That's shown in
25 the middle column of the table. This alarm continues
26 to be ring and cannot be silenced until process

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1 conditions have been removed or, in this case, pressure
2 would drop below 6,800. In addition to this warning,
3 it's significant to note that the control system,
4 without any intervention from the operator, will
5 automatically instruct the control valve at the
6 wellhead to start to close. This high alarm and the
7 automated response to reduce the steam rate are in
8 place such that it -- it's very unlikely a high, high
9 alarm point is ever reached.
10 As you can see from the column on the right, that
11 during circulation, this high -- this high, high
12 pressure alarm is set to the MOP at 7 MPa, and if this
13 pressure condition were ever to be reached, the control
14 valve snaps closed, reducing steam rates to zero.
15 Next side, please.
16 And the preventative controls as -- as described
17 have been proven to be effective. So during Kirby
18 North, there were no exceedences of the 7 MPa maximum
19 operating pressure that is in place to initiate
20 circulation. The KN02-04I possible fracture event that
21 has been included as evidence demonstrate the
22 effectiveness of these controls. So as shown in the
23 graph, the black line representing the bottomhole
24 pressure climbs to 6 MPa, the high alarm point. And
25 this is also shown by a vertical dash line when it
26 reaches that 6 MPa pressure point.

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1 And once reaching this pressure, the control
2 system sounds an alarm, notifies the operator, and the
3 control valve on the wellhead automatically starts to
4 close. So the steam rates shown in red at that point
5 in time start to reduce. You can see the decline on
6 the -- on the red line. In this plot, operators were
7 on the pad by 6 AM or approximately 20 to 30 minutes
8 after the alarm condition had rang in, and we know this
9 by the yellow line on the plot dropping to zero. So
10 the yellow line is the gas rate, and that -- that's
11 manual -- it's a manual valve, so operators are on the
12 pad, closing that valve to drop that gas rate to zero
13 at 6:00. This example shows the control system was
14 effective as -- as there was no need to trigger the
15 7 MPa high, high alarm shutdown.
16 These preventive controls are in place and
17 functioning on the wells in Kirby North today. They
18 are proven to work. They're effective at preventing an
19 overpressure scenario that may impact the GOB, and
20 these same controls will be in place at KN06.
21 And next slide, please.
22 If GOB monitoring is required, there are
23 alternatives available, including any of the four
24 shut-in GOB wells in the pool. But Canadian Natural
25 believes the 100/10-01 well is most suitable. It's
26 within the drainage box whereas other wells are further

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1 away. In fact, 10-01 is within 20 metres of a planned
2 horizontal trajectory, and it's already been equipped
3 to monitor pressure and sensor in the Wabiskaw --
4 pressure and temperatures in the Wabiskaw. Excuse me.
5 Contrary to what's been suggested by ISH, both the
6 bond log and the pressure responses are conclusive that
7 the Wabiskaw is hydraulically isolated. As we've
8 heard, there's a bond log that's been completed on this
9 well in 2015 that was analyzed both by Canadian Natural
10 and a third-party well log analysis expert, and both
11 interpretations conclude that the GOB is isolated.
12 From those interpretations, a continuous channel
13 in the cement that would enable gas flow behind casing
14 does not exist. There is good bond above and below the
15 Wabiskaw in that there's both bond from pipe to cement
16 and from cement to formation. As I quote the -- the
17 analysis, there was, without doubt, definite hydraulic
18 isolation.
19 Further, Canadian Natural is not aware of any
20 operations that were conducted on this well that would
21 compromise the cement integrity, meaning the logs from
22 2015 and the resulting interpretations remain valid.
23 If there were any reason to question the log analysis,
24 you would turn to the pressure and temperature data to
25 remain confident in the well integrity. ISH has agreed
26 that the purchase responses observed from the 10-01 are

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1 not related to the start-up and SAGD operations on the
2 nearby KN05 pad.
3 Canadian Natural and ISH are also in agreement
4 that gas hasn't been flowing from the 10-01 GOB --
5 Wab B GOB zone. What we've heard, however, is that ISH
6 believes -- believes one of the more likely theories of
7 gas flow from the GOB is flow behind casing that
8 suddenly hydrated off in January 2020. For this to be
9 true, a continuous channel extending some 130 metres
10 between the depth of the Wab B and the Grand Rapids
11 would be required to enable the gas flow. The bond log
12 concludes this channel does not exist.
13 In addition, the Grand Rapids well, 16-35, which
14 was supposedly producing the gas that was previously
15 flowing behind pipe in 10-01, does not show a
16 corresponding drop in gas rate at the time of this
17 hydrate formation.
18 The more likely cause of the pressure
19 response observed in 10-01 is a hard shut-in at
20 surface. The bond log evidence indicates hydraulic
21 isolation, and the pressure response observed at 10-01
22 is exactly what would be expected from a flowing gas
23 well that's shut in. In addition to these two points,
24 it's suspicious that this theoretical hydrating event
25 which stopped gas flow in 10-01 occurred within just a
26 few days of when ISH instructed their operations staff

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1 to cease any attempts at restarting offsetting GOB
2 production.
3 Rather than well integrity concerns, the
4 combination of these factors suggest a more likely
5 explanation for the pressure response in 10-01 is that
6 gas was flowing up the tubing string and was shut in on
7 January 7th, 2020.
8 Regardless of your view on the well integrity, the
9 100/10-01 is a suitable candidate. Well integrity
10 issues, in the unlikely event that they exist, can be
11 repaired, and this well can be utilized if monitoring
12 of the GOB is required.
13 Thank you. I'll now turn to Dr. Boone to share
14 his independent review.
15 DR. BOONE: Thank you, Mr. Craig. Good
16 afternoon, Madam Chair and Panel Members. As mentioned
17 previously, I've been engaged by CNRL to provide an
18 independent assessment of their geomechanical work in
19 support of KN06 pad and to evaluate the risks
20 associated with fractures that might be induced during
21 the start-up of SAGD wells at KN06.
22 Next slide, please.
23 The approach I've taken in assessing the risk is
24 to apply industry standard methods. I've assessed both
25 the likelihood and consequence associated with a
26 plausible fracturing event that might've -- might occur

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at one or more of the KN06 wells.
Now, as a starting point, one needs to have an understanding of how the start-up process works as is illustrated by the diagram on this slide and described previously by Mr. Thomsen and Mr. Craig.
Now, when steam is injected into a well at start-up, the pressure typically increases with time. However, the pressure increase is limited by one of two possible mechanisms, the most common one being that the bottomhole pressure reaches a point where it exceeds the hydrostatic head in the wellbore plus the wellhead pressure of the gathering system, and then the injected fluid flow back into the production gathering system. Alternatively, though, and much more rarely, the bottomhole pressure may exceed the pressure required to fracture the formation, and a fracture is then generated.
Now, if the formation is fractured, the key question is whether the injection rate into that fracture and the duration of the injection is sufficient to cause a fracture to propagate into a Wabiskaw gas zone and materially impact a gas production well. This is the risk that is addressed in my report.
Next slide, please.
Now, the approach I have taken is summarized on

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this slide. First, the figure on this slide illustrates the well-established conceptual model for the observed pressure response during a fracturing event. This conceptual model can be used both in interpreting DFITs and in identifying fracture events that may occur during the start-up of SAGD wells.
Now, I've been given the opportunity to review CNRL's internal processes for the evaluation of in situ stress measurements using DFITs, and I can attest that CNRL's geomechanics teams and its contractors, including Mr. Walters, are applying state-of-the-art practices.
Additionally, I've reviewed the prior start-up data, including rates and pressures, for the 41 of 96 operating wells at Kirby North where the pressure exceeded 6 MPa during start-up. Specifically, I reviewed the data for evidence that the wells fractured by looking for the characteristics of a fracture event as shown in this figure. A possible fracture event was identified in one of the 41 wells. Now, this event was subsequently used for characterizing a plausible fracturing scenario as the basis for my risk assessment, and I'll describe this assessment in more detail subsequently.
Next slide, please.

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Now, the chart at the top left of this slide shows the bottomhole pressure and steam injection rates for that one possible fracturing event that was identified. It has a peak pressure, a breakdown pressure. It has a flat region that can be interpreted as a fracture propagation pressure, and there's an instantaneous shut-in event. The fracture propagation pressure and instantaneous shut-in pressure align consistently with the best estimate of the fracture gradient from DFITs.
Now, one cannot be entirely certain that this is a fracture event because the injection rates are not constant. Nonetheless, it's a conservative approach to assume that this is a fracture event.
Some key characteristics of that event are that it has a short duration, about an hour. The total steam that was injected during this period is estimated to be 3.8 cubic metres. However, after accounting for the leak-off into the formation, the volume of steam entering the fracture is estimated to be only 1.8 cubic metres.
Next slide, please.
Now, in order to assess whether an effective stress containment mechanism for fractures exists at KN06, I requested that CNRL provide me with all the nearby DFIT results reported by different service providers in the McMurray sands, McMurray shales or

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mudstones, and the Wabiskaw formations. The locations of these results are shown on the map at the top left. The measured stress gradients for the different formations are shown in the bottom graph. The lines in the graph at the bottom connect points where stress is determined in the same well. Because there can be different -- differences in the methods employed during the execution of stress tests and in the analysis of stresses at each well, it's important to evaluate the stress contrast on a well-by-well basis. Critically, the lower chart shows that for each well, the stress gradient is higher in both the McMurray mudstones and Wabiskaw than it is in the McMurray sands.
It's my conclusion that there's high confidence that a stress contrast will act to contain vertical fracture propagation at KN06.
Additionally, I note in my report that I concur with CNRL's determination that 13.1 KPa per metre is the best estimate of the minimum stress gradient in the McMurray sands for KN06. However, contrary to what ISH seems to claim in their reply report, I have not used that value in my risk assessment.
Next slide, please.
Now, in order to assess whether fluid leak-off is an effective containment mechanism, I requested that CNRL geoscientists provide me with a representative log

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of the strata at KN06 along with the estimated horizontal permeabilities and water saturations. I used this data in conjunction with the standard analytical model to assess the potential for leak-off as a containment mechanism. The analysis shows that the McMurray reservoir sands, the B1 sequence, the A2 sequence, and the Wabiskaw D all act as leak-off barriers that collectively will contain vertical fracture (AUDIO FEED LOST). It's my conclusion that there is a high confidence that leak-off will also act to contain fractures that might be generated during a start-up of wells at KN06.

Furthermore, the simulation modeling work done by Mr. Walters provides complementary evidence and additional confidence that both leak-off and stress-containment mechanisms will act to effect -- act effectively at KN06.

Next slide, please.

Now, it's standard practice in major operating companies to use a formal risk assessment process to address issues such as this. I've been trained in risk assessment processes and participated as an expert in many similar risk assessments. In this assessment, I've utilized the risk matrix shown on this slide that is sourced from APEGA's "Guideline for Management of Risk in Professional Practice."

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As the first step, I determined the risk scenario to be an event where tens of cubic metres of condensed steam enters the Wabiskaw through a fracture induced during the start-up of a well at KN06 pad and that fracture directly impacts a gas well.

Notably, this is an event that is much larger in volume than the single identified possible previous fracture event at Kirby North.

Now, the consequence of the event is financial risk only. It's not an environmental or safety risk. The specific consequence is that at sometime in the future, there could be excessive mobile water in the vicinity of the gas well above KN06 pad. CNRL production engineers have advised that this could be remedied by lifting the water out of the well during a workover. The incremental cost of the workover is estimated to be between 10 and $100,000. The likelihood of such a fracture event at one of the KN06 wells is estimated to be one in ten years. This is determined from consideration of the fracture injection volume that only 1 in 96 prior well start-ups generated a fracture, there are 18 wells planned for KN06, and that start-up is a once-in-a-lifetime event for SAGD wells. The scenario with a likelihood of one in ten years is shown by the circled "one" on the risk matrix and is in the grey zone. Three additional factors have

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been considered in arriving at my assessment of the final risk rating. Stress containment reduces the risk by an order of magnitude. Leak-off is a separate and independent containment mechanism that also reduces the risk by an order of magnitude. And lastly geometry. Fractures are localized events, so in order to impact a gas well, the fracture would have to be proximately close to that gas well. This further reduces the likelihood by at least an order of magnitude. The final risk is the circled "4" on the risk matrix. And we note the final risk rating is clearly in the white or low classification. Typically, this low a risk would not require further mitigation.

Now, I'd also like to note at this point that ISH, in its reply report, offered one alternative quantified risk, that risk scenario being a wellbore channel at the 10-01 which leads to souring of both the Upper Mannville II and the Upper Mannville HH gas sites. And while, in my opinion, a wellbore channel at 10-01 is technically highly unlikely, even if a channel does exist, the obvious mitigation is that it should be repaired. ISH did not consider this simple mitigation option in their risk assessment.

Next slide, please.

The critical conclusion of my assessment is that the risk of a fracture being generated during start-up

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at -- at a SAGD well at KN06 that materially impacts a Wabiskaw gas well is low or white. And, actually, the risk can be considered very low, given its placement on the risk matrix.

The reason the risk is so low is due to four key factors. First, in most cases, fracturing simply does not occur during start-up of Kirby North SAGD wells. Second, due to the short duration of high pressures during start-up, any fracture that might be generated will be small. Third, high-confidence fracture containment mechanisms have been determined to exist at KN06. And, finally, the consequence or financial cost of relatively small volumes of condensed steam entering the Wabiskaw is limited.

Now, a lower white risk does not normally require mitigation. Nonetheless, my assessment does demonstrate that injection pressure and rate monitoring of SAGD wells during start-up can be an effective mechanism for identifying fractures.

I recommended to CNRL that they could enhance their practices in this area, and compared to an observation well, pressure and rate monitoring is much more effective because it provides a monitoring method for all wells, and it can be used proactively. As outlined by Mr. Craig, CNRL is committed to incorporating these recommendations into its operating

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1 practices for the start-up of the KN06 SAGD wells.
2 Thank you for your attention. Mr. Iannattone will
3 now close out the presentation.
4 I think you're still muted.
5 MR. IANNATTONE: Yeah. Sorry about that.
6 Next slide, please.
7 In closing, Canadian Natural's evidence
8 demonstrates that the development of the McMurray
9 bitumen resources for the KN06 drainage box will not
10 impact ISH's mineral rights. You heard from
11 Mr. Lavigne that the mud-filled facies create an
12 effective barrier to steam with three intervals of
13 confinement strata. This is not just our view but is
14 strongly supported in the academic literature.
15 Mr. Sverdahl confirmed no evidence of faulting or
16 fractures observed.
17 Mr. Thomsen -- Mr. Thomsen's geomechanical data
18 and analysis that was further supported by Mr. Walters'
19 modeling demonstrated that a 7 MPa pressure will not
20 hydraulically fracture through the confinement strata.
21 Next slide, please.
22 You heard from Mr. Craig that SAGD observation
23 wells do not effectively monitor and detect possible
24 impacts to the GOB zone. The 10-01 gas well remains a
25 suitable monitoring well. Mr. Craig also presented our
26 enhanced start-up strategy and monitoring for KN06 as

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1 recommended by Dr. Boone.
2 Dr. Boone's independent review concludes a very
3 low risk, and there is no need or reason for
4 modifications to the existing approval to further
5 mitigate the risk.
6 Next slide, please.
7 Respectfully, Canadian Natural wishes to address
8 the following with both the AER Panel and ISH: Over
9 the years, ISH has repeatedly intervened on many
10 regulatory applications, crossing agreements, and well
11 licences associated with the greater Kirby project.
12 Due to these interventions, our development of the
13 Kirby North project has been repeatedly delayed,
14 including the drilling and steaming of KN06 scheduled
15 for 2019.
16 While we appreciate that ISH may be -- may have
17 procedural rights, it is also important to note that
18 significant costs, time, and resources from both
19 Canadian Natural and the regulatory system have been
20 expended on these interventions, including this appeal
21 proceeding. We have made numerous overtures to revolve
22 ISH's concerns, including two attempts made post the
23 AER granting of the regulatory appeal in February 2020.
24 It is Canadian Natural's opinion that ISH is
25 motivated to dispose of its assets in the Kirby area as
26 liabilities exceed the value of the remaining

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1 producible reserves or to restart production from the
2 Mannville II gas pool.
3 We are a majority owner of this gas pool. Any
4 potential impact to this pool would not only affect
5 ISH's gas rights, but it would also Canadian Natural's
6 gas rights. We believe these facts should be taken
7 into account in the Panel's deliberations. The merits
8 of Canadian Natural's technical evidence, along with
9 our proposed mitigative controls and enhanced
10 monitoring measures do not warrant the recession of the
11 KN06 approval as requested by ISH, nor does it warrant
12 ISH's request to reduce the start-up pressure to 6 MPa
13 for an observation well and for 4D seismic.
14 The Kirby North project is well underway and
15 ultimately will recover approximately 377 million
16 barrels of bitumen from this area, which will result in
17 a $1.2 billion NPV10 of royalties paid to the Province
18 of Alberta as well as $133 million per year in jobs and
19 contracts for operations. Over the next 30 to
20 40 years, Canadian Natural plans to invest another 5 to
21 $6 billion at Kirby North. This future investment will
22 add additional jobs in Alberta.
23 In contrast, Canadian Natural has assessed the net
24 present value of the Mannville II gas pool to be a
25 maximum of $620,000 total, with ISH's net share valued
26 of $200,000. We contend that the remedial actions

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1 proposed by ISH are not substantiated, particularly
2 when the value of the remaining recoverable gas is
3 considered. Additionally, any further relief requested
4 by ISH is simply not justified given that compensation
5 from Alberta Energy was provided to both Canadian
6 Natural and ISH for the shut-in impact of the GOB.
7 Again, the technical evidence and commitments to
8 enhance monitoring and controls presented by Canadian
9 Natural demonstrates that the development and operation
10 of the KN06 will not impact ISH's gas rights.
11 Respectfully, Madam Chair and Panel Members,
12 Canadian Natural requests that the AER deny the
13 regulatory appeal.
14 Thank you. That concludes our direct evidence.
15 THE CHAIR: Thank you, Mr. Iannattone.
16 So, Ms. Berg, are you prepared to proceed with
17 your questioning of the Canadian Natural panel?
18 MS. BERG: I am, yes.
19 THE CHAIR: Okay. So let's do that. The
20 one thing I wanted to ask you before you start your
21 questioning is: We are looking at sort of the
22 mid-afternoon break, so if you've got a natural
23 transition from a topic or from a person to a person
24 sometime around -- anytime between, I would say, 3 and
25 3:30, let's -- let's aim for that.
26 MS. BERG: Okay. Sounds good.

Ms. Berg Cross-examines Canadian Natural Resources Limited

Q MS. BERG: All right. So I would like to start with seismic. Mr. Sverdahl, am I pronouncing your name correctly? I think these questions are for you.

A MR. SVERDAHL: Yeah. Mr. Sverdahl.

Q All right. CNRL states that the 2008 Kirby 3D seismic has frequencies up to 145 hertz; is that correct?

A Correct.

Q What dominant frequency does the Wabiskaw McMurray level contain?

A Around 105 to 110 hertz.

Q With this frequency content, could visible displacement of less than 7 metres be seen on the images that CNRL provided?

A Yes.

Q If fractures are seen in core and displacements aren't visible on seismic, what further geophysical analysis would CNRL pursue?

A Sorry. Can you repeat the question. If fractures are seen in core ...

Q If fractures are seen in core and displacements aren't visible on seismic, what further geophysical analysis would CNRL pursue in the normal course?

A Well, I think, if I'd go back to the last question, you

asked if faults less than 7 metres are imageable on seismic; correct?

Q Well, I think you answered that question, so --

A So I'm going to specify with I don't -- we don't think that faults 2 metres, plus or minus a metre, are imageable on seismic. So unlikely small displacement faults or fractures seen on core would be able to be imaged at all on seismic.

Q What about a 7-metre displacement?

A We would believe we would be able to see that quite readily at Kirby North.

Q Okay. And what further geophysical analysis would you pursue if you were to see --

A 7-metre faults would be easily seen on the -- the products that we have already supplied to ISH for -- within our hearing submission.

Q Besides the geophysical methods provided in CNRL's responses -- and that is time and depth structure, isochrons, a single semblance slice, and visual cross section inspection -- what other geophysical methods did CNRL use to interpret the seismic?

A For faulting specifically?

Q Yes.

A Yeah. We have looked at some other attributes within the area; however, they did not show anything more than what -- what has been shown for fault discrimination at

Kirby North. The tools that we've used have been more -- more useful for understanding reservoir quality, reservoir thickness. Some of these methods have been mentioned previous, before, like spectral decomposition. We have looked at -- somewhat at curvature. Curvature attributes showed mostly differential compaction techniques -- or differential compaction processes and not faulting.

Q So how long has CNRL used the Geomodeling Technology Corp.'s Attribute suite software?

A Geomodeling has been a part of CNRL's toolbox as long as I've been an employee at CNRL, so 2004.

Q All right. I'd like to bring up an aid to cross that we filed yesterday. It's Aid to Cross Number 3, and it's entitled "Geomodeling Attribute Studio."

MS. BERG: Ms. Turner, would you be able to turn that up?

MS. TURNER: Certainly. We're -- we're going to do that.

MS. BERG: Thank you.

THE CHAIR: Will you want to have this mark for reference purposes, Ms. Berg?

MS. BERG: Yes, please.

MS. TURNER: So that would be Number 89.01 for identification only, Aid to Cross Number 3.

MS. BERG: Thank you.

EXHIBIT 89.01 FOR IDENTIFICATION PURPOSE ONLY - Aid to Questioning Number 3 (Ish Energy Ltd.) Geomodeling Attribute Studio

Q MS. BERG: Sir, do you have that in front of you or --

A MR. SVERDAHL: Yes, I do.

Q -- are we -- all right.

So as I understand it, the Attribute suite contains the entire workflow for advanced quantitative interpretation. So my question is: Does CNRL make use of this workflow?

A CNRL uses tools from each of our software packages. We don't necessarily use a full -- full workflow from any individual tool. We -- we analyze and -- and -- and come up with our own best practices and -- from each software -- piece of software that we own and -- or that we -- we licence and come up with our own best practices for seismic interpretation.

Attribute Studio is a piece of software that we do use, and we use it for some certain things but not others. So I wouldn't say we use the whole Attribute work -- Attribute Studio work flow for a complete interpretation at -- at Canadian Natural or on the Kirby North project.

Q Could you please turn to the second page of the exhibit and scale down -- or, sorry, I'm going to ask the

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1 person controlling the -- the image to scale down to
2 small -- "Small-Scale Faults," please, at the latter
3 part of the page.
4 So as you see, Attribute suite has a small-scale
5 fault and fracture zone identification capability using
6 structure attributes and 3D-image analysis and
7 filtering. Did CNRL make use of these capabilities in
8 the 2008 Kirby North 3D?
9 A I would start to answer this question that I am
10 slightly familiar with this workflow. This tool was
11 used on a project -- was tried and tested, I should
12 say, tested on a project outside of heavy oil that one
13 of the geophysicists on my team was working on, and
14 conclusions from that test was that this tool was able
15 to pick up the large-scale faulting that most competent
16 seismic interpreters were able to interpret themselves
17 but really had difficulty in picking up the small-scale
18 faulting, the subtle, little features, from the
19 background noise.
20 So, no, we have not used this tool at Kirby --
21 Kirby North to help predict small-scale -- small-scale,
22 subseismic-scale faulting, nor do we believe it's
23 applicable.
24 Q Did CNRL make use of the pre-stack functionality of
25 Attribute suite and specifically the amplitude
26 variation with -- and I'm going to mispronounce this --

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1 Azimuth AVAZ or velocity verification with Azimuth VYAZ
2 analysis to look for subtle directional amplitude and
3 velocity variations within the confining strata?
4 A No.
5 Q All right. Thank you.
6 At paragraph 115 of Exhibit 30.02 -- if we could
7 go to that. Actually, perhaps what I'll do is just
8 read into the record: (as read)
9 CNRL makes note of a semblance slice at
10 Wabiskaw B of plus 17 milliseconds to
11 approximate the -- the mid-B1 mudstone.
12 And I believe you have that semblance slice at Tab 30
13 of the same exhibit, which is at PDF 120, so if we
14 could move to that.
15 THE CHAIR: Can we go to PDF 120.
16 Q MS. BERG: And my question, sir, is: Can
17 CNRL describe how they determined Wabiskaw plus
18 17 milliseconds was at the mid-B1 mudstone level?
19 A MR. SVERDAHL: Yes. This was an
20 approximation. We used synthetic seismograms to, in
21 this case, understand approximately how much time is
22 required to slice down from the Wabiskaw B pick to the
23 mid-B1 mudstone level. Again, it's an approximation,
24 and this slice obviously has impacts from traces above
25 and below that seismic interval.
26 Q So if CNRL suspected a fault on the semblance volume,

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1 what further steps would be taken to strengthen the
2 fault interpretation?
3 A Well, as shown on my -- on my direct evidence slide,
4 which is a similar tab to this one -- could we bring
5 that up, please. That would be Exhibit 88.0.2 and
6 Slide 32, please.
7 Okay. So on this map -- this is the pre-stack
8 time-migrated version of the same semblance slice that
9 we were looking at just previously. I annotated the
10 ISH-postulated faults in purple, A to A Prime and B to
11 B Prime. The first step would be looking for
12 lineations in the direction of -- of these postulated
13 faults.
14 The next step would be going to -- back to the
15 actual seismic sections themselves. So if we could
16 move back to B to B Prime, that would be Slide 31. And
17 if we zoom in, you're going to see small 'X's kind of
18 at the Wabiskaw -- between the Wabiskaw B and
19 approximate top of these post B incision levels. Those
20 'X's correspond to roughly where those postulated
21 faults were occurring. I would then inspect the
22 seismic line for offset on the seismic markers.
23 7 metres of offset, as -- as I previously testified,
24 would be easily recognizable as displacement on seismic
25 markers at the Wabiskaw B, Paleozoic, or within the
26 reservoir interval itself. Inspection of this line

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1 shows no indication of faulting, and, thus, we would
2 concluded that no faulting is here, and we would stop
3 our interpretation there.
4 Q Could you go back to the previous slide, please. So
5 why did CNRL decide to switch from the original time
6 domain to a depth domain?
7 A Yeah. This -- you're right. This -- this section is
8 in depth. I think it's just a preference of the
9 geophysicist that worked this project, is to work in
10 depth. So when we did our IR submission, we submitted
11 this -- this slice in depth.
12 Q Is this slice meant to be a direct comparison with the
13 semblance slice that was given at Exhibit 30.02,
14 PDF 120?
15 A It's very comparable, slight -- there may be slight
16 variations just due to the velocity process in
17 converting the pre-stack time-migrated version to
18 depth.
19 Q Why do you think that the same discontinuity features
20 in the depth slice are not seen in the time slice?
21 A Well, pre-stack time migration --
22 Q This --
23 A Yeah. Sorry. Go ahead. Finish your question.
24 Q No. You go ahead. No. That's fine. Sorry I
25 interrupted you.
26 A Yeah. Pre-stack time migration tends to focus

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1 reflection vents a little more than -- than a
2 post-stack time-migrated volume. So I would -- I would
3 say that -- that this -- this figure has more -- a more
4 focused image than the previous one, and that's why
5 you're seeing, perhaps, somewhat less of those spurious
6 lineations that were annotated by ISH in their
7 presentation yesterday. Those are the ones marked --
8 roughly marked in in green dash.
9 You can also notice on this -- this version quite
10 a bit of east-west banding, very faint, but it's --
11 there's an obvious trend there. That's -- that's due
12 to acquisition footprint and not related to any geology
13 at all.
14 Q Just one moment, please.
15 So why is the footprint on the depth slice if --
16 and not on the time slice if the depth slice has better
17 imaging?
18 A I wouldn't say that it isn't on the time slice. I
19 think it's -- it's there. It's just not as -- as
20 focused.
21 Q All right. Again, one moment. I might be done with
22 you and moving on to geology.
23 Thank you, sir. I am going to move on to geology
24 now.
25 A Thank you.
26 Q And, again, I would like to pull up another aid to

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1 cross that was filed yesterday. The -- it's Aid to
2 Cross Number 1, development of the stratographic
3 framework at KN06 modified from CNRL, and so if I could
4 get that pulled up, please.
5 MS. TURNER: Are you looking to have that
6 as -- marked as for identification only?
7 MS. BERG: Likely, yes. I don't think
8 we're going to get any agreement on it. I -- I just --
9 yes. I'll -- I'll walk the witness through it. But,
10 yes, identification is good.
11 And so what number is that exhibit?
12 MS. TURNER: That's 89.02, for
13 identification only, AQ Number 1, development of the
14 stratigraphic framework.
15 EXHIBIT 89.02 FOR IDENTIFICATION PURPOSE
16 ONLY - Aid to Questioning Number 1 (Ish
17 Energy Ltd.) Development of the Stratigraphic
18 Framework at KN06
19 Q MS. BERG: And I'm not sure who would be
20 handling the line of questions regarding this, so --
21 A MR. LAVIGNE: Mr. Lavigne would be prepared
22 to discuss this.
23 Q Okay, Mr. Lavigne. I am wondering -- I'm not sure if
24 it's possible to pull up two -- two different figures
25 electronically, but I am going to be comparing this to
26 the -- to what is found at Exhibit 65.01, PDF 29, and

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1 so that was the original development of the
2 stratigraphic framework for KN06.
3 So do you have that in front of you, sir?
4 A MR. LAVIGNE: Yes, I do. Thank you. I was
5 going to ask you to pull that up maybe as well.
6 Q Yeah. I'm not sure if they can do that, and I just
7 wanted to check.
8 MS. BERG: Does the Panel have both of
9 those exhibits available? It might be easier to follow
10 along.
11 THE CHAIR: I do, but I don't know if
12 Ms. McKinnon and Dr. Zaitlin do. We'll see if they can
13 do a split screen here.
14 DR. ZAITLIN: I've managed to pull both of
15 them up.
16 MS. BERG: Okay. And, Ms. McKinnon?
17 MS. MCKINNON: Yes. I'm fine. Thank you.
18 Q MS. BERG: Okay. All right.
19 So before we go through this, Mr. Lavigne, I want
20 to note that the purpose of my question is to clarify
21 the differences between how CNRL and ISH see the
22 development of the stratographic framework at KN06. I
23 think that understanding these differences will be
24 helpful to the Panel in this proceeding.
25 So beginning at Time 1, what CNRL calls the "B2
26 regional sequence" and ISH calls the "McMurray C";

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1 correct?
2 A MR. LAVIGNE: No, no. I don't believe
3 that's true.
4 Q Okay. Sorry. I am going to pull this up as well.
5 A I could help you with that, if you'd like.
6 Q Just one moment, sir. I'm just going to -- I hadn't
7 anticipated that this would be a difficult line of
8 questions, so --
9 MS. BERG: Sorry, Stephanie. I'm trying
10 to find this. It's -- great. Thank you.
11 So we have them -- I have them both in front of
12 me, and so I'm just saying, beginning at Time 1, which
13 CNRL calls the "B2 regional sequence," if we look over
14 to ISH's -- or, actually, Mr. Mathison's stratigraphic
15 framework, the label is "McMurray C;" correct?
16 A MR. LAVIGNE: That is correct.
17 Q Okay. And what CNRL calls the "McMurray C," ISH calls
18 the "lower McMurray"?
19 A That is correct.
20 Q Okay. All right. So moving to Time 2, we have erosion
21 occurring and the same labelling of the strata that we
22 had in Time 1; correct?
23 A Correct. With, I might note, the addition of --
24 Mr. Mathison has placed the McMurray C mudstone on the
25 diagram, which Canadian Natural disagrees with.
26 Q Okay. That's fine.

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Now, moving to Time 3, what CNRL calls the post B2 regional sequence -- or "post B2 reservoir unit", rather, ISH calls the "McMurray B2 valley fill"; correct?
A That is correct.
Q Okay. And what CNRL calls the "post B2 non-reservoir unit" is what ISH calls "his"; correct?
A I might like to clarify for the Panel that Canadian Natural also says that unit is compromised of his. "His" is not a stratigraphic term.
Q All right. But you agree on the labelling?
A The labelling as is. You're correct.
Q All right. So moving to Time 4, what CNRL calls the "regional lower B1 sequence" ISH calls the "McMurray B2"; correct?
A Could you please repeat that. I just want to make sure I'm clear.
Q Yeah. No problem.
So for Time Number 4, what CNRL calls the post B2 -- sorry. Sorry. Moving to Time 4, what CNRL calls the "regional lower B1 sequence," ISH calls the "McMurray B2"; correct?
A Thank you. That is correct.
Q Okay. And then at Times 5, 6, and 7, we actually seem to have some agreement in labelling with both parties calling the next strata the "mid-B1 mudstone," the

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"regional B1 sequence," and the "A2 regional sequence"; correct?
A I might add a slight correction, that ISH does not call the "mid-B1 mudstone." ISH calls that the "B1 mudstone."
Q All right. And then, finally, at Time 8, we have the development of the Wabiskaw D, and, again, there's some similar labelling but a difference in how the parties use the Wabiskaw D in the vicinity of the KN06 box. Is that fair?
A Yes. It's fair. Although I would suggest that in the -- in the ISH version of this diagram, the Wabiskaw D -- the depth of erosion has been highly exaggerated relative to its proximity to the KN06 box.
Q All right. Thank you, Mr. Lavigne.
MS. BERG: So I now have some questions regarding his, and if you could please go to Exhibit 2.01, and that's the public record to PDF 139.
Q MS. BERG: Now, CNRL has previously said, as I understand it -- and I'm just going to try to locate the paragraph that I'm looking for here. It's midway -- actually, is this the correct -- sorry. This is PDF 29, and I'm looking for PDF 139. Sorry if I'm mumbling.
All right. And I'm just looking at that paragraph in the middle of the page, and I'm just going to read

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it out. (as read)
The heterogeneities in the -- in question are represented primarily by accumulations of mud clast breccias as well as mud in inclined heterolithic stratification, his, associated with laterally accreting point bars.
Canadian Natural is choosing to develop well pairs encountering reservoir heterogeneities in these selected drainage patterns because the volume of resource is too great to strand as part of the proposed development.
And it goes on to say that: (as read)
In summary, Canadian Natural believes that the heterogeneities presented are primarily baffles to steam-chamber development.
So my question regarding this is: Did you include the his in your McMurray pay isopach in KN06 as it appears you did on your isopach map?
A Yeah. When -- when considering well placement relative to his or breccias, as mentioned, it's important to realize that they are at the bottom of the reservoir. And as we have stated in our direct-evidence submission, the lateral extent of mudstone his beds lower in the reservoir is much less, and so they are included as reservoir as we feel that steam will be able to move around those.

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Q So why do you include it elsewhere as part of your confining strata?
A No. I think you misunderstand. The his that we include as part of our confining strata is mud-rich. The reservoirs, like all fluvial systems, show a fining-upwards character where both grain size decreases and mudstone content increases in a vertical fashion. And as you go near the tops of those reservoirs, the mudstone content becomes too high to effectively allow steam to pass through it.
That does not occur at the injector and producer level. We are coming in well below that. And so our confinement strata -- as the paper that ISH submitted by our colleague, Bryce Jablonski, not all his is created equal, and his has different percentages of sand and mud, and as the his units become muddier near the top, then the lateral extent also -- of individual mudstone beds also increases.
Q All right. If I could please ask you to go to Exhibit 53.02 at PDF 136. Yeah. It's the confidential -- so 136 of the confidential 53 .02 exhibit.
MS. TURNER: One moment, please.
MS. BERG: No worries. We're making you jump around a lot. And so, again, it's PDF 136. All right. Thank you.

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Q MS. BERG: So we see here -- we see here, Mr. Lavigne, that the base of the non-reservoir for this particular well is his; correct?
A MR. LAVIGNE: I'm just going to -- could we zoom that just a little bit, please.
Q And we want to go to the right-hand side, I believe, to the bottom.
THE CHAIR: It looks like we jumped pages.
MS. BERG: Yeah. It looks like we jumped pages. So 136, the bottom right is where we really need to focus.
I think we're going -- I'll have to buy the people at the AER a beer or something after this proceeding, after making this poor --
THE CHAIR: As long as we're socially distanced.
MS. BERG: Yeah, yeah. Send the beers over.
Okay. I think we're where we need to be.
Q MS. BERG: So, Mr. Lavigne, base of your non-reservoirs his; correct?
A MR. LAVIGNE: I'm sorry, Counsellor. Can you please clarify what well we're looking at? This doesn't look like the graphic that I have.
Q This is the 11-01?
A Which 11-01? Is that --

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Q 1AA.
A AA/11-01. I apologize.
Q No worries. There's a lot of material in this proceeding.
A I was looking at it, and I was looking at the wrong well, so I will be just one second. Okay. I apologize. I'm ready to go. Please proceed.
Q Yes. So the base of your non-reservoir in this well is his; correct?
A In that well, yes. And if I could request that we go down one photo, please, to the next page, page --
Q And we will in just a moment. I just have one more question on this page. Do you agree that the bottom two core columns are predominantly sandy his?
A No.
Q No.
And how would you characterize them?
A I would actually look at that and look at the sand-mud percentage. That is probably about maybe 45 percent sand, and so we would use cutoffs. I believe our cutoff is about 60 percent mud. I would call it "mixed his."
Q You would call it "mixed his."
And so, yes, let's go to the next slide, because I was going to ask you to go there. And just to clarify again, this is the base of the non-reservoir, and then

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we go to the top of the reservoir, I believe, on the next page. And this too is his?
A Hard to say, actually. There's a mix of clasts and beds in there, so that one's a little bit tough. The -- in -- immediately adjacent, in the second tube from the bottom near the Depth Marker 472, those are clearly clasts that have been ripped up, broken, and cracked. So I would suggest that you're at the top of the point bar sequence, and the previous photo that we looked at on page 136 is where the reservoir becomes too muddy to allow steam to pass vertically up into the muddier parts of the upper point bar.
Q One moment, please.
All right. You would agree, sir, that the -- the top of the reservoir is -- is thin his?
A No. I wouldn't say that, either.
Q Okay. And so how would you characterize it?
A I would say that the top of the reservoir -- keeping in mind that a well is a 1D point, and I would say that the top of the reservoir is defined at the point where it becomes mud-dominated and the sands above that are -- would be disconnected from the steam chamber. This is what we do when we do RST analysis, like I -- like I showed you this morning, and we look at each well, and we pick and evaluate a point within the heterolithic muddying upwards his package, where we

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think that the abundance and thickness of mud beds is too great to allow steam to enter.
Q All right. I am going to move on to your opening statement, and if I could -- and, sorry, I don't have the exhibit number for that.
THE CHAIR: I believe it's Exhibit 88.02.
Q MS. BERG: Okay. So if I could ask you to please go to PDF 30.
A MR. LAVIGNE: All right.
Q So the question is this: Does differential compaction account for the drop in the Paleozoic at the 1AA/03-01 well?
A No. I think the erosional relief on the Devonian surface is what accounts for the low in the Devonian. The -- the differential compaction effects are a result. If you look at the shading of the gamma logs in the -- in the logs overlaid on the seismic slice in yellow, I believe Dr. Zaitlin was commenting on this this morning. And what you'll see is that in the two wells on the left, they're almost entirely sand up to the confinement strata.
When we look at the well on the right-hand side, there's very little sand in that well, and, again, touching on one of Dr. Zaitlin's points this morning, if you'll notice where the southern edge of that "VV prime" is on the map in the upper right, you'll notice

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that it's on the outside of the KN06 drainage box. The reason why it's outside the KN06 drainage box is because there's very little sand reservoir there. This is an older terrace within the valley fill that contains very low net-to-gross sediment. The drainage box is defined in the fairway of the highest net-to-gross sand. And so the reason for the differential compaction effect is that there's less sand in that part of the stratigraphic column, and it compacts more.

So it's a little bit coincidental that the differential compaction you see in the reservoir and confining strata coincides with the low in the Devonian. They're two completely different concepts, which I believe my colleague Dr. -- Mr. Sverdahl discussed earlier.

MS. BERG: Could we move to PDF 23, please.

Q MS. BERG: I am just wanting to ask how you account for the total disruption of strata within the siderite cemented interval. And I apologize if I am completely mispronouncing these geological terms.

A MR. LAVIGNE: Geology has all kinds of ridiculous terms.

Q It does indeed, yes.

A Siderite is an iron carbonate cement that's common in

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most of the deposits in McMurray. The reason why that particular piece of core is so badly damaged is that during drilling, as the drill bit is going down through the softer sandstones and mudstones above it, it hits that hard cemented layer, and so the drillers have to weight up on the drill string to force the core to continue to cut, and so that is the -- that is how you introduce centreline and petal fractures. It's from the increased weight of the drill string that makes that characteristic fracture pattern.

And I would say that, in addition, we -- we commonly see that in cemented zones, and the one fracture that Mr. Sverdahl demonstrated in the water leg of -- of the well is also in a calcite cemented horizon. So drilling -- coring -- the coring penetration rate is set up to optimize the recovery of core. It's not set up to prevent core-induced fracturing. And so often you will see that the drillers weight up at those horizons, and we induce fractures in those cemented zones.

Q So you wouldn't see these as open fractures?

A No. They completely do not exist in the reservoir.

Q Just another question regarding this. Do you recognize what you referred to as "B1 mudstone" in, I believe, the same photo as the -- do you -- do you recognize that what you referred to as "B1 mudstone" contains

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carbonaceous mudstones?

Sorry. I thought that this was PDF 23 of the opening. I apologize. I apparently have the wrong exhibit.

So would you -- one more question. Would you not see these as open fractures?

A No. As I said, they do not exist in the reservoir. They are a complete artifact of the coring process.

Q Okay. I am going to ask you to move to exhibit -- just one moment. I'm going to -- 65.01, PDF 13, please. And we see here Table 4.1 of that exhibit. So in Table 4.1, CNRL indicates there are no fractures present in any confining strata except where there is some evidence of drilling-induced fractures in core samples in the upper B1 and the mid-B1 mudstone. My question is: How many of these cores are from KN06?

A I would say none of them.

Q And why is that?

A Because they're the ones that ISH chose to illustrate. Mr. Mathison made the claim yesterday that he did see lots of fractures in the core submitted in the KN06 box, but for some reason, ISH chose not to highlight those.

Q This is -- just one moment, please.

Mr. Lavigne, I -- I just wanted to take a moment to confirm. So 65.01 is CNRL's exhibit, so this

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Table 4-1 is CNRL's Table 4-1. So I'm going to ask again: How many cores for this table are from KN06?

A We analyzed 20 image logs in the KN06 box and didn't find any fractures in the confinement strata.

Q And how many cores?

A I believe it was 25 cores.

Q Are there 25 cores in the KN06 box?

A That --

Q I would think not.

A That might be the ones that we -- we evaluated.

Q I'm going to come back to this one, perhaps, after the break, and I would ask that you -- that you double-check on that because I'm -- I'm quite certain that it isn't 25. So I would ask if -- rather than -- than spend additional time, yes, if you wouldn't mind looking that -- into that in the break, and I'll come back to it.

A Certainly, Counsellor.

Q Okay. So -- so I do understand that CNRL claims there's no drilling-induced fractures visible within the confining strata.

MS. BERG: And, actually, it is 3:00, and I'm about to start a longer line, and so --

THE CHAIR: This might be good place for a break?

MS. BERG: Madam Chair, I'm in your

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1 hands. I could go another half hour or -- or ...
2 THE CHAIR: Would half an hour only get
3 you partway through your next line of questioning, do
4 you think?
5 MS. BERG: It would likely just be
6 partway, yeah.
7 THE CHAIR: Okay. Why don't we take a
8 break now of half an hour, give everybody a chance to
9 get up and away from your screens, and reconvene back
10 in the virtual hearing room at -- well, it will be 29
11 minutes -- at 3:30.
12 (ADJOURNMENT)
13 THE CHAIR: So, Ms. Berg, before we start
14 back in with your questioning of the Canadian Natural
15 panel, I just wanted a couple -- to cover a couple of
16 things. We were thinking -- and hopefully our counsel
17 has had a chance to chat with both you and
18 Ms. Jamieson -- about stopping in and around --
19 sometime around 5 today, if there's a convenient spot
20 where that fits for, whether it's before or a little
21 bit after.
22 MS. BERG: Yeah.
23 THE CHAIR: And then finish whatever
24 you've got. I'm assuming you're not going to be
25 finished, but you may be finished in the morning, and
26 then we'll just shift tomorrow's schedule all forward.

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1 I guess we have time tomorrow to work with.
2 MS. BERG: And that's fine. Yeah.
3 THE CHAIR: Okay.
4 MS. BERG: That's perfectly fine. Thank
5 you.
6 THE CHAIR: And the second thing I just
7 wanted to raise is the question of any comments that
8 you each have about the mode and timing for final
9 argument. Currently on the schedule, we've got time
10 for it to be done orally online on Friday.
11 So we can waive -- if we think we're going to stay
12 with the schedule -- and so far it looks like we are --
13 we can carry on with that, but if you have strong views
14 one way or the other about wanting -- preferring to do
15 it in writing or potentially another -- another form or
16 another day, we're open to considering that.
17 MS. BERG: Well, yeah, I -- I -- I do
18 have some -- some views on that. While I -- while I'm
19 sure that we would all love to wrap up on Friday, this
20 is a proceeding that, I think, everybody would agree is
21 heavily visual, and I think that for that reason
22 written argument would be more appropriate.
23 So that's my view on -- on written argument, and
24 we are fine to -- to move written argument forward in
25 an expedited way, you know, within -- argument within a
26 week. I don't know what the view is on reply argument,

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1 whether there would be a reply, and I'll, yeah, just
2 wait to hear from you, Madam Chair, with regard to your
3 thoughts on that, but -- but we would prefer written
4 argument. It's just more appropriate given the nature
5 of the material in this proceeding.
6 THE CHAIR: Typically, the AER practice in
7 a fully oral proceeding is to allow for a reply, if
8 it's required.
9 So, Ms. Jamieson?
10 MS. JAMIESON: Can I take a moment to consult
11 with my client? I'll just say that Canadian Natural,
12 you know, was prepared to go with the Panel's suggested
13 schedule on Friday. So we are prepared to do oral
14 argument on Friday in that time slot, but given
15 Ms. Berg's comments, if I could just take a moment and
16 confer with my client just to see if that changes
17 anything for them.
18 THE CHAIR: Sure. Please do.
19 MS. JAMIESON: Thank you.
20 (ADJOURNMENT)
21 MS. JAMIESON: Thank you, Madam Chair.
22 I think the bottom line for us is that we're ready
23 to go on Friday. We're prepared to do it orally, and
24 we'd just like to see it get done. We do acknowledge
25 Ms. Berg's comments and -- in terms of moving it to a
26 written final argument process, and we would just defer

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1 to the Panel in terms of what decision it wants to
2 make.
3 THE CHAIR: Okay. Well, rather than take
4 up Ms. Berg's -- any more of Ms. Berg's time in terms
5 of questioning Canadian Natural witnesses, the Panel
6 will confer at the end of the day, and we'll let you
7 know in the morning, if that works.
8 MS. BERG: That's fine.
9 THE CHAIR: Thank you.
10 MS. JAMIESON: Thank you.
11 THE CHAIR: Over to you.
12 MS. BERG: Yes. All right.
13 Q MS. BERG: So I do have some additional
14 questions on core fractures, and, Mr. Lavigne, I assume
15 that I'll continue to direct those questions to you?
16 A MR. LAVIGNE: That's correct.
17 Q Okay. All right. So if I could ask you to turn to
18 Exhibit 63.01, PDF 91.
19 MS. TURNER: So, Madam Chair, that is the
20 confidential exhibit number for ISH's reply submission.
21 The -- the version that came in after the Panel's
22 letter Exhibit 80.1 is -- the public version is 63.02.
23 So just to clarify which one you're looking for.
24 MS. BERG: So I am looking for the -- the
25 confidential exhibit, and -- and perhaps we should just
26 address this at the outset. I am going to be referring

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to a number of exhibits in 63.01 as well as 53.02 in the next line of questions. I understand that those are confidential exhibits, but it's also my understanding that the AER has taken the view that -- that reference to individual -- and it's all core -- individual core photos is not confidential, but, again, Madam Chair, I'm in your hands there. If --
THE CHAIR: No.
MS. BERG: If we want to go in camera, I am fine with that.
THE CHAIR: No, no. You interpreted it correctly, and I think we had another one similar to this earlier in the day. So please proceed.
MS. BERG: Okay.
Q MS. BERG: So 63 -- and I always say "63.01". I believe it's 63.02, PDF 91, please.
A MR. LAVIGNE: Counsellor, could you please give me that well.
Q It's the AA/08-02 well.
A Thank you.
Q And I'm hoping they'll pull it up for us.
THE CHAIR: I'm assuming they're working on it.
MS. BERG: Yeah.
MS. TURNER: So to confirm, Ms. Berg, sorry, you would like the confidential Exhibit 63.01

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and not the public version 63.02?
MS. BERG: Just one -- one second, please.
So 63.01 is the unredacted version, and I'm actually going to ask you to go to PDF 95.
MS. TURNER: Okay.
MS. BERG: Thank you.
Sorry. I'm just waiting for that to come up before we --
THE CHAIR: Yeah.
MS. BERG: -- continue.
THE CHAIR: No. I know.
MS. BERG: Yeah.
Q MS. BERG: All right. So if you could go five columns from the left just to the right of the black scale, you'll see there a pyrite-filled fracture. Do you -- do you take the view, sir, that -- that this is -- does not provide evidence of fractures or faulting in the -- in the KN06 area?
A MR. LAVIGNE: It's -- it's hard to -- it's hard to say. I am not convinced that actually is a fracture. To me, that looks like a burrow. It's very curvilinear, and it -- and it doesn't -- it doesn't have any -- it doesn't have a plainer aspect to it. And so if you were to ask me, I would interpret that that's a diagenetically pyrite cemented burrow.

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Q All right. Let's move to PDF 96. And for PDF96, is it also CNRL's view that there's no fault or fractures present?
A That -- that may be a fracture in the Clearwater A, which is not in the confinement strata, and as it's above the caprock, it's not relevant to these proceedings.
Q All right. Moving on to -- if we could move to Exhibit 53.02, and I'll be going through a number of pages there, if we could start with 316. And, again, this is a confidential exhibit, and it's PDF 316.
So would you agree that this interval has at least -- at least three intervals where the stratigraphic layering is completely destroyed?
A I wouldn't say "completely destroyed". I can see background fabric, but I would agree that it's very highly bioturbated.
Q So with regard to the second column from the bottom, do you agree that at forty four point -- 444.7 there's a termination of strata that cuts diagonally down from the left?
A At 444.7 ...
Q Do I have the --
A You -- I presume you're referring into the rubblized zone from coring. You can --
Q I don't know.

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A -- see the bits of white around it from the tube. That piece of core has been rotated and broken away in the core barrel, and you'll notice as well that it's near the bottom of the core interval, which would be on the right side of that too.
Q So we're referring to the -- the second -- sorry. I'm pointing in a way that -- that you're not able to see -- the -- the second column from the top; correct?
A Yeah.
Q Okay.
A And maybe about a quarter of the way over from the right-hand side.
Q Yeah. And so are you referring to the truncation that rises at a high angle toward the left?
A Yes. I would suggest that that entire approximately 10 centimetres of core has been rubblized in the core barrel.
Q Oh, okay. All right.
So moving on to page -- could you zoom in on the -- sorry, on the lower part, the -- the last column -- sorry, the -- on that page. Back to 316. You know what? Just one moment, please.
So just with regard to the -- the lower -- the lowest column, is it your view that this is intense bioturbation?
A I presume you mean about the 10 centimetres just below

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the red line?
Q No. Actually, further to the right.
A Oh, okay. Are you looking at the dark-light contrast?
Q Yes.
A I -- I think that's actually bedding. They look like low angle wavy beds, and there's a -- there's a slight erosion surface within the stratigraphy, and that probably is why there's a slight saturation difference across those -- those two zones. So I would suggest that's sedimentary bedding.
Q Okay. All right.
Let's move to PDF page 452 of the same exhibit, please. So in this core -- we're getting it flipped -- at the base, the lower most column, there's a fractured Paleozoic overlying this -- overlaying -- sorry, a mudstone that you referred to as "post B2". Is that correct?
A Base of the post B2, yeah. That's how it's labelled.
Q Okay. And what's the black staining in the mudstone that the base of the overlying water saturated sandstone?
A That's a cemented interval, and so it has such low permeability that oil often bleeds out of the core face. So it suggests that cementation is occurring probably just after charge, but that's a cemented interval.

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Q Okay. Okay. If we could move to PDF 416, and if you could direct your attention to the lower column, left-hand side. And do you agree the red line represents the boundary between the Paleozoic and overlying base post B2?
A Yes. I believe it is right there.
Q What is the nature of the sediment overlying the unconformity?
A It's trough cross-bedded sand with abundant carbonaceous organics that's been completely cemented by calcite.
Q And would you agree the overlying sand is water saturated?
A Yes, I would.
Q Okay. And is this anomalous, to have bitumen saturated cemented sands below water saturated sands?
A No. It -- it -- it tells you a story of the timing of charge versus cementation. So, no, I -- I don't -- I don't think that's anomalous at all.
Q All right. Moving on to PDF 92 of the same exhibit.
All right. And I guess I have a few questions regarding this particular well. So just one moment.
So the cored interval covered includes the top of the lower B1, mid -B1 mudstone and is in turn overlaying by the upper B1. Is that correct?
A Yes. That's what the labels are, yeah.

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Q Okay. And this core is a continuation of -- just one moment. Just one moment.
All right. Would you agree that there is a thin B1 here?
A The mid-B1 mud appears to be about 15 to 20 centimetres thick.
Q Okay. And do you recognize that there's a fracture from the base of the B1 all the way up to the base of the core?
A No, I do not.
Q You don't see that at all?
A No, because it's not a fracture. That is a bioturbation fabric that contains -- it's -- it's highly bioturbated. The top of the lower B1 is a subaerial exposure surface, and that sort of fabric of trace fossils, including ichno fauna such as Naktodemasis is -- is a common suite of -- of nonmarine paleosols, and so, no, they are not fractures. That's biogenic disruption of the sediment.
Q Okay. Could you please move -- the same exhibit -- page 102.
So looking to Core Tube 3 from the top, would you agree that in the lower 25 centimetres, just above the bitumen water contact, the mudstone layers are highly distorted?
A Yes. That's because they're part of a basal channel

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lag. Those are clearly ripped up mud clasts that have not been fully lithified at the time they were reincorporated into that high-energy channel sand deposit. These are very common throughout the McMurray formation.
Q Okay. And so, sorry, what is the nature of the sediment underlying the basal water sand of the post B2 reservoir unit. And I'm sorry.
A That's actually --
Q We just covered it.
A That's actually part of the same sand unit. That's a diagenetic concretion of calcite, but you can still observe the original sedimentary fabric within that concretion.
Q Okay. Moving on to PDF 231.
A I'm trying to look at the core photos, but they keep flipping on me.
Q Yeah. I just don't look at them until they're done.
All right.
A That's good advice.
Q So do you concur that the lower 40 centimetres of core below the top lower B1 label is highly contorted and typical horizontal stratification has been completely destroyed?
A Okay. Sorry, Counsel. I did hear the second part. Could you just point me to the right spot on the photo

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1 again.
2 Q So the lower 30 centimetres of core below the top
3 lowered B1 label.
4 A The -- oh, the top lower B1. Okay. 40 centimetres?
5 Q Yeah.
6 A Yeah. Okay. So in the -- around 465 or slightly up
7 above or below?
8 Q Yes. I believe so.
9 A Yeah.
10 Q I'll have to trust you on that. You look at these more
11 than I do.
12 A I sure do.
13 There -- yeah, again, that's -- that's a
14 bioturbation fabric. That's a mudstone bed that's been
15 almost completely -- completely bioturbated, and so a
16 lot of the beds are deformed. There's a lot of burrows
17 in there, but it's -- it's -- yeah. That's normal
18 bioturbation. That is quite characteristic of the B1.
19 Q Okay. And immediately below this interval Core Tube 2,
20 do you see a high-angle truncation of mudstone beds?
21 A Is that the feature just below Dean-Stark 32? I just
22 want to make sure that I'm talking in the right place.
23 Q So I just know that it is immediately below in Core
24 Tube 2.
25 A Core Tube 2. Okay.
26 Well, I'm going to -- I'm going to speak as if

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1 that's where you mean because I think that's
2 probably --
3 Q So -- so my understanding is to the right side of
4 this -- to the right-hand side of the second -- the
5 second tube.
6 A I look at that as centimetre scale mud beds that have
7 been completely turned up by bioturbation.
8 Q Okay. Could we move to page 238. Same exhibit.
9 All right. So do you agree that the sedimentary
10 fabric of the interval overlying the Paleozoic -- so my
11 understanding is that that's 503.25 to 503.65, Column 2
12 and 3, from the bottom -- has been destroyed, and the
13 upper boundary is a high-angle fracture?
14 A No. I -- I -- I don't think I do. I'm just trying to
15 look. I'm going to need just one second. This is
16 the --
17 Q Yeah. That's fine.
18 A -- the AB/07-01 well; correct?
19 Q It is.
20 A Okay. My apologies. Yeah. That -- that's drilling
21 disruption. One of the things that you see in water
22 sands is that they -- they don't have bitumen holding
23 them together, and so they tend to fall apart.
24 So what we notice when we core those particular
25 water sands is that our core recovery is often
26 drastically reduced, and so what I might suggest to you

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1 there is the disruption that you're talking about is
2 from the drill bit encountering the Paleozoic.
3 You can see a nice petal fracture at the end of
4 that tube on the bottom part, and I think that that
5 unconsolidated liquid saturated water sand has been
6 distorted and squished in the core tube.
7 Q Okay. Just one moment, please.
8 Mr. Lavigne, you'll be happy to know that I don't
9 have any more core photos to show you.
10 A Well, you did very well.
11 Thank you to the AER for doing that. It's very
12 tedious. I know.
13 Q Yes. Probably more for me than you.
14 So who would be answering questions on the oil
15 water contact? Maybe I'm not done with you,
16 Mr. Lavigne.
17 A Aha. Okay. May I have just a brief moment to confer
18 with my colleagues?
19 Q Yeah.
20 A Ms. Berg, I'll start the line of questioning if -- I
21 think I know where you're going with this, and, if not,
22 perhaps I could have the opportunity to pass it off to
23 one of my colleagues.
24 Q So would you agree that the oil water contact will
25 represent a near horizontal surface at the time the
26 reservoir was filled and that hanging a cross section

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1 on the oil water contact would give us an understanding
2 of the structure of the reservoir at that time?
3 A I'm -- I'm afraid I'd have to strongly disagree with
4 that. I think that's a very dangerous practice,
5 especially since in -- in oil sands reservoirs, after
6 charge, the degradation of the oil to bitumen happens
7 very quickly. And so, essentially, that oil water
8 contact freezes in place. Any structural movement or
9 changes to that after the fact has the affect of
10 bending and distorting the oil water contact.
11 I think that for a microsecond in time that may
12 have been a horizontal surface, but it's completely
13 unreliable to -- to ascribe any horizontality to it.
14 Q Do you agree that biodegradation of the oils in the
15 McMurray formation -- actually, sorry. Just -- just
16 one moment.
17 THE COURT REPORTER: You're unmuted,
18 Mr. Iannattone, just so you know.
19 MS. BERG: Would I be able to ask you to
20 go to Exhibit 29.03? And if you could go to the WW
21 prime. And I'm not sure. I think it might be the last
22 page of that exhibit. These are not easy to see.
23 Okay. And I just would appreciate it if you could
24 find the oil water contact for us between -- at the
25 bottom of the wells between the 06-01 and the 07-01.
26 We -- we need -- actually, if the court reporter

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1 or whoever is handling that could scroll down to the
2 bottom. That would be appreciated. That's what we're
3 looking at.
4 And, yeah, just up a little bit now. And if you
5 could -- if you could move it over a bit to the left,
6 and just one more over. It's just on the far
7 right-hand side. If you could just point to it. I'm
8 sorry. We will try to get -- now we need to just move
9 up a bit, and I think that should do it for this
10 particular well. Can you point to the oil water
11 contact on this well -- on this particular well.
12 THE CHAIR: Is it supposed to be marked?
13 I don't see an oil water contact clearly marked.
14 MS. BERG: It's -- it's not -- sorry.
15 I -- it isn't clearly marked, and so I was asking
16 Mr. Lavigne if he could mark it for us, if he could
17 tell us where it is.
18 A MR. LAVIGNE: I apologize. I was muted
19 there for a second.
20 Q MS. BERG: No worries.
21 A It's interesting how we would evaluate this. You --
22 you would look at -- I'm trying to understand the
23 scale. These are very difficult logs to work with, I
24 might add. That would be, say, 498 possibly.
25 There is a little bit -- as the resistivity moves
26 to the right as you go up through the well, there may

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1 be a little bit of transition zone, and probably
2 maximum oil saturation would occur at about 493 metres.
3 It would be full oil saturation.
4 So this is another problem with: Where is the oil
5 water contact? That's a very fair question in this
6 well because it depends how you define the base of --
7 the base of the oil column, if it's based on a cutoff
8 of resistivity or if it's based on facies. It's --
9 it's very difficult to answer exactly where that is,
10 but it's somewhere in that range between 498 metres and
11 493 metres.
12 Q All right.
13 MS. BERG: And then if you could just
14 move to the adjacent well. So I'll ask the court
15 reporter to just move the cursor over to the left,
16 please.
17 THE CHAIR: I think it's actually one of
18 our hearing coordinators.
19 MS. BERG: One of the hearing
20 coordinators. Thank you.
21 Sorry. I -- I feel your pain because I've tried
22 to navigate these on my computer, and it's not easy.
23 So, again, moving down, please. Okay. And just
24 stop there.
25 Q MS. BERG: Okay. Are you able to look --
26 to locate the oil water contact for the adjacent well?

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1 A MR. LAVIGNE: I'm an elderly gentleman, and
2 my eyes have a lot of trouble seeing that at that
3 screen.
4 Q Okay.
5 A I -- I'm -- I know this is dangerous, but I'd like to
6 zoom again, please. Okay. I think we have it there.
7 So --
8 Q It's -- it's over actually a bit -- it's -- it's just a
9 little bit -- yeah.
10 A Oh, goodness. Okay. Thank you for that. I was
11 looking at the wrong well.
12 So I presume -- just so we're completely clear,
13 this is the well that's immediately above the ISH
14 Energy Limited structural cross section WW prime label?
15 Is that correct?
16 Q I --
17 A Yeah.
18 Q -- believe so.
19 A Okay.
20 Q Yeah.
21 A Right where the cursor is now?
22 Q Yeah. I believe so.
23 A Okay. So it looks like the ten-ohm cutoff there would
24 be at about -- maybe about 492 metres.
25 Q All right. Okay. Thank you.
26 So I have a question regarding IHS, and I think

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1 that we will need to go to exhibit -- Exhibit 2.01,
2 PDF 28 and 29.
3 Do you agree that -- that there are sandy IHS
4 going up to the top of the reservoir in this figure?
5 A In which well?
6 Q Just to the right of the 1AA, I believe.
7 A Would that be the 1AA/11-01 or the 1AA/12-01?
8 Q I have elderly eyes as well, so it's on the -- the one
9 to the right.
10 A On the right-hand side?
11 Q Yeah. On the right-hand side, so immediately to the
12 right of that.
13 A It looks to me like there's a package of mixed to muddy
14 IHS that covers almost the entire model slice.
15 Q And what about that middle section?
16 A Which -- which middle section are you referring to?
17 Q I'm referring to this. Or what are we -- okay. The
18 yellow. Yes. The yellow. Sorry.
19 A I'm not sure what -- what you're meaning by "yellow."
20 Q Okay.
21 A There's a lot of yellow.
22 Q Yes. There is, indeed.
23 All right. If we go to the right of the -- of the
24 1AA -- I'm not sure if it's -- I think it's the 11-01,
25 we -- if you go to the right of that, there is a
26 section on the bottom which -- and I wish that I was

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1 able to mark it for you -- which is -- is just below --
2 just below the base of the A2. You see the -- the blue
3 line.
4 And if you go below that, there is an area where
5 there's very little of the black and the brown and the
6 light brown. That's where -- yes. That's exactly --
7 A Oh, okay. Okay. Thank you for clarifying that. I
8 wasn't --
9 Q Yeah.
10 A -- sure exactly where you meant.
11 If you refer to the line of that cross section in
12 the upper right-hand side of that slide, the AA prime,
13 the blue line that goes through the KN06 box --
14 Q Yeah --
15 A -- what you'll see is that -- you'll see the three
16 wells that have been projected onto the line of
17 section, and then you'll see there are no wells along
18 the rest of the section. So these -- you'll also
19 notice below the yellow area that you're talking about,
20 there's a little orange blob there as well.
21 Q M-hm.
22 A It turns out there's no well there. There's no data
23 there, and this is merely a stochastic postulation of
24 facies between well control. So this -- you know, this
25 is one realization of a geostatistical model.
26 MS. BERG: Can you move to the next PDF,

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1 please, the next page.
2 Q MS. BERG: All right. And the same
3 question for this particular -- for this particular
4 figure and looking to the well on the far left this
5 time.
6 A MR. LAVIGNE: My apologies. Are you --
7 Q You'd agree -- you'd agree this was -- this is sandy
8 IHS?
9 A No. I -- well, like I said, I don't know exactly where
10 you mean, but in that --
11 Q So it's the --
12 A -- well --
13 Q It's the one -- so it's the well to the far left.
14 A Yeah.
15 Q It's the 1AB/05-01.
16 A Yeah.
17 Q And so would you agree that the area around that is
18 sandy IHS at the top?
19 A It looks like there's some mixed and muddy IHS there as
20 well. But -- but, yeah, there's a little bit of sandy
21 IHS at the top of the reservoir.
22 Q So you would say a little bit? It -- it seems that
23 it's almost -- from my eyes -- and -- and, yeah, the --
24 the two blind people looking at the -- at the exhibit
25 here.
26 In my view, it looks like there's quite a lot.

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1 Where do you see the additional strata?
2 A Well, when I look at -- when I look at that, the well
3 log does not seem consistent with the interpretation of
4 sandy IHS there.
5 You'll note that in that sort of really ugly
6 green-ish yellow colour is -- the gamma log is -- is
7 deflecting sharply to the right as you go through that
8 unit and that the dark streak that cuts across the top
9 of that well just below the green line that marks the
10 top of the incision has muddy IHS. So I think that's a
11 very heterolithic muddy package.
12 The other thing I might point out, when we log
13 cores and we go through and pick facies, what we --
14 what we do is we sort of take -- we take this sand
15 percentage and the mud percentage, and we come up with
16 a facies. These geostatistical models often have
17 enormous numbers of cells, and so the vertical
18 resolution on how you pick the facies depends -- it
19 depends on the cell size of your model.
20 So this, again, is a realization of -- that this
21 may be an upside case. I'm not sure. This is -- this
22 is just one realization of something that has populated
23 something that looks like sandy IHS.
24 I might also point out, however, that the -- the
25 interval below the base of the A2 down to the green
26 line, the incision top, looks to be, I would guess,

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1 almost 10 metres of mudstone, and the base of the A2 is
2 picked in that well, meaning that the base of the A2
3 mudstone is there.
4 So I would still argue that even if the post B2
5 non-reservoir is heterolithic, there's still over
6 10 metres of muddy confinement strata present in that
7 well.
8 Q All right. I would like to move on to some questions
9 regarding GCMS, and so who would respond to those?
10 A I would be happy to respond to those.
11 Q Okay. And so if we could go to Exhibit 30.02, page 92.
12 And, actually, if instead I could get you to go to
13 page 108 first of that same exhibit. Thank you.
14 So would you agree that your interpretation of the
15 GCMS data from the AA/11-01 well is based on the one
16 dimensional advection-diffusion modeling of Adams 2008?
17 A No, I would not.
18 Q You wouldn't?
19 A No.
20 Q Okay. Then could you explain that, please.
21 A This is a schematic diagram taken from a piece of
22 academic literature that's meant to schematically
23 illustrate the concept of the variations and
24 concentration of hydrocarbons. This is not real data.
25 This is just -- this is just plotting to show the
26 trends that one might observe if one were analyzing

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1 real data.
2 Q Okay. Why don't we move on to page 92 of the same
3 exhibit, and this is a diagram from Fustic -- Fustic?
4 I'm likely mis --
5 A Fustic.
6 Q Fustic. I'm getting Fustic, Fustic.
7 -- et al., 2011, and you would agree they provide
8 a different table based on ground truthing the modeling
9 of Adams from 2018 on reservoirs in the McMurray
10 formation?
11 A Again, this is a schematic diagram. This is not real
12 data.
13 Q Okay. Could you tell me what distinguishes the
14 barriers in the Fustic and et al. paper from -- from
15 Adams?
16 A Well, if I recall, Adams is actually a co-author on
17 that paper. She's part of the "et al." in the "Fustic,
18 et al." So this is her work as well. This is just a
19 modification. It's -- it's a very similar diagram, and
20 I might suggest that it was just redrafted to be
21 incorporated to put into this paper.
22 Q So why -- it appears to us that you used Adams' GCMS
23 interpretation based on the one dimensional modeling in
24 the figure at PDF 108 rather than the one in Fustic
25 at 82. Is that correct?
26 A No. We didn't use any of those. They're schematic

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1 diagrams that we put into our submission so that
2 members of the panel who might not be familiar with the
3 technology would have some sort of a guideline to see
4 how the -- the potential barriers and baffles in the
5 GCMS can interpret it. This is just a visual prop.
6 Q So using this as a visual prop -- and let's compare it
7 from the GCMS data from the 1AA/11-01 well, just using
8 the Fustic, et al. chart from one oh -- page --
9 page 109 of Exhibit 30.02. Sorry. What page are we
10 on?
11 So which chart from Fustic, et al. would best
12 represent the GCMS data from this well?
13 A Well, it depends. The -- the -- there's a whole bunch
14 of data here. These -- these trends, these -- these
15 dashed lines, actually were first proposed by
16 Schlumberger, who did the analysis, who has expertise
17 at interpreting GCMS signatures. Then we bring it
18 and -- and plot it into this graphic.
19 So we're not using the Adams. That is a schematic
20 guideline to suggest what it is you're looking for in a
21 scatter of GCMS data that would indicate the presence
22 of a barrier baffle. So we're not using the Adams, et
23 al. That's simply --
24 Q But I -- I am using it, and I am asking --
25 A Why would you do that? It's a --
26 Q I -- I am --

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1 A -- schematic --
2 Q I am --
3 A -- diagram.
4 Q -- simply -- I am simply asking you, sir, to look at
5 the data in Tab 19 and then look at the diagram from
6 Fustic, et al. and tell us which chart best represents
7 this GCMS data.
8 A Well, again, the limits of it -- if you go to -- for
9 example, if we could just maybe enlarge this figure
10 that's on the screen slightly.
11 Q Sure.
12 A Thank you very much.
13 For example, if you go to the top dashed line and
14 look at the A2 mudstone, what you'll see there is that
15 the -- the blue diamond at about 457 or so metres.
16 Then if you go up, you'll notice the blue diamond at
17 about 455 metres has a backstepping to the -- to the
18 left.
19 And that is -- that has been interpreted as --
20 it's -- the concentration profile suggests that the --
21 the hydrocarbons present above the A2 mudstone were
22 isolated by shales, and they degraded in isolation from
23 the oil water contact below. That backstepping, which
24 I believe is Figure C of Adams or Fustic, et al.
25 Q So you would agree that it's Figure C of --
26 A For --

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1 Q -- Fustic --
2 A Well, for that barrier.
3 Q For that barrier?
4 A For that one barrier. You realize there's a bunch of
5 barriers depicted in this diagram that ISH has
6 commented they -- they don't -- or believe they're
7 overstated.
8 So in my evidence submission this morning, I
9 demonstrated the ones that correspond to Canadian
10 Natural's confinement strata, and so if you go to the
11 bottom red dashed line and you look at around 477,
12 you'll see the step change to the right. That also is
13 a barrier. It's that offset.
14 Q And that's Adams; correct?
15 A No. That's not actually an Adams because that's a
16 schematic illustration. They don't actually illustrate
17 the case that shows a right step change.
18 Q So could we flip to Adams, page 108 of the same
19 exhibit. So which -- which schematic are --
20 A So I would say that at 477 metres in the 11-01 well on
21 the KN06 box, there is a case 'D' where there's a right
22 step change in the data that supports there's a
23 barrier. I'll point out to the -- for the Panel's
24 benefit that that particular pick is within the post B2
25 reservoir. This is not even in the confinement strata.
26 I'll also point out that at Jackfish, Canadian

Natural has done geochemistry work in 26 wells on 17 operating pads, and we have confer -- and matched this with temperature data. So we have a high degree of confidence that these data sets are actually compatible and comparable in the same confinement strata in the same post B2 reservoir.

Q All right. Just one moment, please.

Do you have additional GCMS to confirm this?

A This is the only -- this is the GCMS that we submitted from a representative well on the KN06 pad.

Q Okay. And so why did you not submit some additional GCMS to confirm?

A Why -- why would we do that? This is the only one that's relevant to the hearing.

Q All right. I'm just going to take one moment. I might be quite close to finished this line. Just one moment.

MS. BERG: All right. I am done this line of cross, and so, Madam Chair, I could -- I could continue for a while, but I do have over half an hour, and so I'm in your hands. We can keep going, or -- or I'll try to wrap it up tomorrow.

I do think I would be more efficient tomorrow because I'll have a little bit more time to work with some of my witnesses to tighten up the cross tonight.

THE CHAIR: So how much time roughly, then, in total do you think you have left? Just

roughly.

MS. BERG: I would say -- so right now, I would say an hour, but I would hope I could cut that down by about 15 minutes overnight.

THE CHAIR: Okay. I think -- well, I was going to say since our current schedule, if we had kept going today, has us done at about 12:30 tomorrow. I think taking the break now and finishing your questioning tomorrow morning and then going into staff, Panel, et cetera only shifts us a little ways after lunch. So I don't see a problem with that.

Ms. Jamieson, are you okay with that?

MS. JAMIESON: I have no concerns with that. That's fine.

THE CHAIR: Okay. So let's do that, then.

So, Canadian Natural, as at the lunch break, you are still under oath. You'll remain so overnight, and you may only confer with each other, not your counsel, or anybody outside of the witness panel.

With that, we are adjourned for the day until 9 AM tomorrow morning. Thank you.

PROCEEDINGS ADJOURNED UNTIL 9:00 AM, OCTOBER 15, 2020

CERTIFICATE OF TRANSCRIPT:

We, Andres Vidal and Sarah Howden, certify that the foregoing pages are a complete and accurate transcript of the proceedings taken down by us in shorthand and transcribed from our shorthand notes to the best of our skill and ability.

Dated at the City of Calgary, Province of Alberta, this 14th day of October 2020.

Andres Vidal, CSR(A)
Official Court Reporter

Sarah Howden, CSR(A)
Official Court Reporter