Page 1

CHAIRMAN:
Q. I hope we all smiled for the camera, did we? So where are we, madam. We are going to get to Mr. O'Reilly or Mr. Johnson?
O'REILLY, Q.C.:
Q. Mr. Chairman, we have reviewed the transcript. There are some issues with respect to the accuracy of who is saying what, who is responding--
CHAIRMAN:
Q. Uh-hm.
O'REILLY, Q.C.:
Q. --and I spoke to counsel about that, and I think we don't need to take up the Commission's time on that. We can correct that offline sort of thing.
CHAIRMAN:
Q. Sure, yeah.
O'REILLY, Q.C.:
Q. It's mainly questions between Mr. Humphries, I think, and Mr. Kean. They seem to be a little confused, but we can fix that out afterwards, so that's it, so -
CHAIRMAN:
Q. Editorial accuracy.

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O'REILLY, Q.C.:
Q. That's it, right, and we can fix that, so I think it's probably over to Mr. Johnson, yes.
MR. JOHNSON:
Q. Okay, good morning, Mr. Chairman, commissioners. Good morning, gentlemen. I'd just like to circle back a little bit. A few issues arising from yesterday's questioning by my friend, Ms. Greene, and then there's some customer questions that I've been receiving, which I'll try to get before you as well for your comment this morning. I guess the first one I would address to Mr. Humphries. It has to do with the probabilistic adequacy studies, and I think yesterday you indicated that these probabilistic adequacy studies would not be addressed to DG3, and you indicated that incorporating that level of evaluation in your decision-making process could have significant implications, and we feel it needs to be addressed with stakeholders, the regulator and the customers, and I just wanted you to advise us in Nalcor's judgment what are the significant implications that could arise because that wasn't developed on the record.

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MR. HUMPHRIES:
A. Yes, thank you. When we look at these more detailed probabilistic reliability studies, we start to introduce factors such as the cost, societal cost, of the interruptions to customers and items like that that we traditionally have not included in our cost effective analysis and our lease cost decision-making to date, and when we--you look at the inclusion of these things, while in principle, yes, these things do have cost, but in relation to what we currently do in our isolated scheme as compared to what may be the case in an interconnected scheme, when we consider a customer outage and the value of a customer outage, it causes a little bit of concern in how that gets treated, particularly in the isolated case as it is today, and will probably continue to exist for a long time, and the fact that we do incorporate under frequency load shedding, and in fact customer interruption is a significant contributor to the overall reliability of the system, and it will continue to be so. That's something that's worked for us in Newfoundland over the

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years, and it's not the norm. As I said yesterday, it's not the norm, but if we start to introduce to put a cost on those interruptions, I have the concern that we may be unduly disadvantaging, for argument's sake, an interconnected alternative because we have a solution that works. It probably doesn't work anywhere else, but it works here, and is that really fundamentally where we want to go, and we need to assess that and fully explore what the implications of these studies would mean on a go-forward basis, and with respect to both alternatives, you can look at it from the interconnected alternative, and these types of outages are not going to be prevalent in the interconnected phase. When we interrupt the customer it's going to be because we have a problem, and it's not--we're not interrupting him to--or them to necessarily prevent further deterioration of the system, but that's the standard in the isolated case, and it's going to continue to be, so all I'm saying from the perspective--we have to think through--and this whole philosophy and look at how it applies to the

Page 5

way we have planned our isolated system, and it has been reasonable, and will it continue to be reasonable to do that, and if it's not--it's a fundamental shift in our thinking, and all I'm saying, that we're not at a stage to make a determination if we want to move off that yet, or even if we should, or it's prudent to do it, so that's the basic concern we'll have with--and the major issue with those types of studies.

MR. JOHNSON:

Q. The other point I'd like to ask about is in relation to the discussion around 11 gas turbines, and it was indicated that if we were to advance or put in 11 gas turbines to provide the same level of reliability on some measurements as the isolated option, that that would involve a 350 million dollar effect on the CPW to the infeed option, which is not currently reflected in the CPW analysis for that option, and I'd like some clarity on Nalcor's position on this potential proposition for rate payers.

MR. HUMPHRIES:

A. You mean what the--the impact that that 350

Page 6

million dollars would be?

MR. JOHNSON:

Q. Well, what's the probability that this needs to be incurred from Nalcor's judgment?

MR. HUMPHRIES:

A. From a probability perspective as, you know, we've indicated in the past, the probability of an event, loss of the--failure of the Labrador-Island link, it has a design as we propose of 1-in-50-year failure but, then again, we combine that with the probability of that failure resulting at a time when it actually has an impact on customers. The probabilities get down fairly low, in excess of 1-in-50-year event. It's somewhere in the range of probably a 1-in-200- to 1-in-300-year event that we would have--be actually in a situation where we would have the levels of unserved energy that we have indicated in our deterministic modelling that was there, these exposures that we would be trying to cover off with the 11 gas turbines, so it's a small probability that we would be there.

MR. JOHNSON:

Q. The question to Mr. Goudie came on--in

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connection with Page 219 of the transcript, Line 6, and your answer was in connection from my learned friend, Ms. Greene, having to do with the financial analysis that you did for the PPA, and there being--and was there any contemplation of changing the price, and Ms. Greene asked you--"I was--just all you did was escalate it by two percent and you assumed there would be no off-ramps. If there was any change in market conditions relating to pricing that Hydro would be locked into paying this as a take or pay," and your answer was, "If Hydro required less power than provided for in the supply arrangements, then Hydro and Nalcor would work to monetize that differential and supply requirement in order to minimize any rate payer benefits." Were you indicating--is that what you were intending to -

MR. GOUDIE:

A. No, it's not. As I read that today, obviously, what I meant to say was to minimize any rate payer impacts.

MR. JOHNSON:

Q. I thought so, okay.

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MR. GOUDIE:

A. Thank you.

MR. JOHNSON:

Q. Thank you. Further clarification as it relates to the AC Integration Study, and I'd address this to Mr. Humphries. Mr. Humphries, as you're aware, the MHI report said at Page 53, for the record, that "In the absence of integration studies there may be unidentified risks in proceeding with the project at this time," and they say, "For example, the studies could identify the requirement for additional back-up generation, new transmission, enhanced protection schemes or other systems, additions," and I was interested in knowing whether you would accept that these are the types of recommendations--or the types of requirements rather that could be identified in an integration study as MHI states.

MR. HUMPHRIES:

A. Yes, they are the types of things that would normally be identified in those studies. The level of back-up generation, I'm not positive that that would come out of the integration study in itself but, again, it's possible.

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MR. JOHNSON:

Q. Because there was--I guess when I looked at the transcript from February 13th, I was--at Page 193, and maybe it's worthwhile to bring it up. At Line 18 I--we're having a discussion about costs that have been contemplated, and I said "When you say all those items got costed in, would that have contemplated costing in any back-up generation or beefed-up lines," and your answer was, "No, the system integration does not address system reliability issues." Can you clarify? Is there any conflict between what MHI is saying and what you were saying on that point?

MR. HUMPHRIES:

A. No, and from the perspective of the back-up generation, I guess, if--and the--an integration could identify the requirement for back-up generation if the configuration--if we're not able to perform adequately through a given contingency situation, whether that be a line out or trip of the pole not, but from the preliminary--our--the previous studies that we've done in 1998 and the preliminary work we did in preparation for DG2 internally, we did

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not identify back-up generation as an issue at all, just to clarify that, you know, from the integration perspective.

MR. JOHNSON:

Q. Okay, no, that's good. I guess then what I'd like to do is turn to some questions from the customers and interested citizens who want me to put forward some questions on their behalf for the appropriate panel members' consideration. The first question has to do with the proposed upgrade to the Holyrood facility in relation to environmental upgrades, and the question states as follows that "MHI states that the question as to whether this is necessary, as switching to .7 sulphur fuel has accomplished as much as is necessary to meet provincial targets for sulphur dioxide," and the first question related to this is--Nalcor helped draft the 2007 Energy Plan--what did Nalcor recommend the 600 million scrubber upgrade, which MHI states is not needed?

MR. BENNETT:

A. I'm the--the 2007 Energy Plan is a document issued by the Government of Newfoundland

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Labrador. It's a statement of provincial energy policy. The policy commitment is fair.

MR. JOHNSON:

Q. The second question is how many homes are directly affected by the Holyrood thermal plant, and I presume they mean by "omissions." I don't know if you have the answer to that.

MR. BENNETT:

A. I don't have a specific answer, but it would say that the omissions of the Holyrood thermal generating facility have been an ongoing community concern. Those concerns have been expressed on a continuous and regular basis in a variety of different situations, and I think we'd all recognize that those are a public concern.

MR. JOHNSON:

Q. The next question was has Nalcor considered a relocation plan for residents who want to move, and Nalcor could then resell the homes to others who may not have a problem living near the plant.

MR. BENNETT:

A. No, we have not considered the relocation plan.

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(9:45 a.m.)

MR. JOHNSON:

Q. Okay. The next question is if, according to the MHR report, presumably at Page 196, which is what the questioner suggests, if there was no 600 million dollar Newfoundland policy upgrade, the CPW preference would 1.8 billion, and the questioner says, "This is a bit reduction of 400 million dollars in the PCW," and the question is "Please comment."

MR. BENNETT:

A. There's still a 1.8 billion dollar preference for the interconnected scenario.

MR. JOHNSON:

Q. Next question has to do with the--with respect to 100 percent equity financing of the generation component of Muskrat Falls. "Could you please ask the following questions: Please provide the likely capital structure for Muskrat Falls Generation Project, which was used to examine the Bruce power type rate profile over time with foregone equity income matched with higher future returns in order to prevent rate shock and to create lower rates than would apply under cost of service?" Do

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you follow that?
MR. BENNET:
A. No, I can't say I followed that one.
MR. JOHNSON:
Q. Okay.
CHAIRMAN:
Q. Thank you very much.
O'REILLY, Q.C.:
Q. I was wondering in terms of the reference question. I'm just wondering how -
CHAIRMAN:
Q. Does anybody understand the question, and I'm not trying to facile, but I have no idea what's being said but, I mean, you know, I'd take your -
MR. JOHNSON:
Q. I think what the question may be getting at is the--Nalcor has developed a power purchase arrangement, and I think the materials suggest that it was in some fashion modelled after the use of such a mechanism elsewhere, and I don't know if rereading would add to it, or perhaps I'm best off putting in writing and just proposing it in that fashion.
MR. GOUDIE:

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A. If I can make a suggestion, that type of question--I mean, it has a certain convoluted character to it. If you submitted it as an RFI, we could sort of properly think our way through it and understand the question and answer it.
MR. JOHNSON:
Q. Okay, and just for clarity too, Mr. Chairman, as regards to--I think as you can probably appreciate, I'm getting questions that are not necessarily within the reference altogether--
CHAIRMAN:
Q. Sure. Oh no, yeah.
MR. JOHNSON:
Q. --and I guess I've sort of made a policy decision on that where--I pose the question as it's asked--
CHAIRMAN:
Q. Yes.
MR. JOHNSON:
Q. --and then if Nalcor wants to say it's outside, I just leave it at that as opposed to saying, "I'm going to censor it" -
CHAIRMAN:
Q. Yeah. I think that's fair, Mr. O'Reilly,

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don't you?
O'REILLY, Q.C.:
Q. Yes, that's fair and it's not the--I mean, the question--the nature of the question seem to get down into rates. It was difficult to follow, and I was just wondering for purposes of moving and informing this process, whether it was down into--you know, was something that we should be considering, but I think Mr. Goudie's suggestion probably is the way to deal with it if that's reasonable.
MR. JOHNSON:
Q. Okay.
O'REILLY, Q.C:
Q: Yeah.
MR. JOHNSON:
Q. Okay, I'll do that because some of the other questions have to do with the Bruce power arrangement as well--
O'REILLY, Q.C.:
Q. Yeah.
MR. JOHNSON:
Q. --and I think I'll do it in that fashion. Here is a question that I've been asked to put to you as well. It regards a Nalcor statement

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in Exhibit #36, and the statement quoted, and I'm not sure whereabouts in the exhibit that this statement comes from, but the quote is, "This escalating supply price is lower than would be indicated initially by the cost of a service framework and is applied only to power actually used by rate payers early, the earlier burden placed on rate payers at that time is minimized." Is that in accordance with what that exhibit says?
O'REILLY, Q.C.:
Q. And just so everybody can follow, that's in the latter half of the last paragraph on Page 1.
MR. JOHNSON:
Q. Okay.
O'REILLY, Q.C.:
Q. I can give you exactly the right place there.
MR. JOHNSON:
Q. Okay, and the question in relation to that, Mr. Bennett, would be, "Does this artificially lower power rates created for the 2017 rate payer require future generations to pay higher rates to compensate for the early shortfall?"
MR. BENNETT:

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A. I think at the outset maybe it's important to point out there is no shortfall as such with the return and equities earned over the entire 50-year period. Another observation, I think, that might be worth considering would be the cost of the PPA compared to the cost of the isolated alternative, and in all cases Muskrat Falls energy both early in the study period and late in the study period is lower cost than the alternative, and the alternative being increased reliance on thermal generation at Holyrood.

MR. JOHNSON:

Q. And I think it would be probably appropriate if--because I know--I realize I'm putting these to you and they're complex questions, so that if Nalcor felt that they wanted to add more to the answer in writing, I guess we could do it in that fashion. The second part of the question is again pertaining to Exhibit 36--is "If the 2017 rate payer only pays for the power actually used, like 40 percent of Muskrat Falls, who pays for the other 40 percent. If there an unpaid deficit that has to be paid future generations." I guess it's

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driving at similar points.

MR. BENNETT:

A. That's a similar point, and the answer is that all the costs of Muskrat Falls are recovered in the PPA, so there's no outstanding costs to recover.

MR. JOHNSON:

Q. The third question relates to a further statement in that exhibit, which is quoted as follows: "A supply price for its output set in 2010 constant dollars helped address intergenerational equity issues associated with large, public expenditures," and I'm asked to "Ask Nalcor to comment on the intergenerational equity issues and, in particular, does the 2035 rate payer have to pay more so that the 2017 rate payer can pay less?"

MR. BENNETT:

A. And I guess the response is in a similar context as I mentioned earlier in comparison to the isolated alternative, even the 2035 rate payer is paying less than they would've otherwise in that isolated scenario.

MR. JOHNSON:

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Q. Could you just expand on that so that we can-- so somebody watching can fully understand what you're -

MR. BENNETT:

A. Steve, do you want to step into that?

MR. GOUDIE:

A. Yeah, sure, it's Steve Goudie. I think with respect to the particulars of that third question, the intergenerational equity issue would be that under a conventional cost of service the return on equity for the utility is highest in the early years, and as that asset is depreciated, the return on equity declines, so that the unit cost of production from that facility would be highest in its early years and lowest in its later years, so people 50 years from now will pay very little for the power from a long-term generation asset like a hydro plant, whereas people in the early years would be paying more. Under the PPA approach that we have, the real 2010 price for power from that facility is constant across the entire planning period, so the only adjustment to that price is for this two percent general inflation rate.

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MR. JOHNSON:

Q. Okay.

MR. BENNETT:

A. So people 50 years from now in inflation-adjusted terms will pay exactly the same price per unit of power as we would pay in 2017.

MR. JOHNSON:

Q. So the current generation is not hosing the future generation, is that the takeaway?

MR. BENNETT:

A. Well, I wouldn't characterize it like that, but -

MR. JOHNSON:

Q. I guess the customer wants to know that, right?

MR. BENNETT:

A. Well, I mean, under existing cost of service, customers 50 years from now get a very good deal. They get a better deal than the people today.

MR. JOHNSON:

Q. So if you could put it in Bay d'Espoir terms, for instance, I guess that would be an example of how now we enjoy the fact that it's an aged asset and it's been depreciated and -

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MR. GOUDIE:
A. That's correct.
(10:00 a.m.)
MR. BENNETT:
A. And maybe building on that point, the customers in 2068, who have an asset that's--whose costs are fully recovered will have a similar situation as we've seen with Bay d'Espoir.
CHAIRMAN:
Q. Can't wait. Excuse me.
MR. JOHNSON:
Q. Okay. I guess there was a--I guess a related question--and, again, there might be a term of reference issues with it, but maybe not. It pertains to the answer to the consumer question that was posed--that I posed on behalf of a consumer, being CAKPL-27, which was asked--or was answered in a revised format yesterday, having to do with the incremental stand-alone kilowatt hour cost of Muskrat Falls power delivered to Soldier's Pond and, essentially, they are wishing me to direct your attention to Page 6 of the reply and, in particular, Column 5, which has a nominal,

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annual cost per megawatt hour of 239 dollars of megawatt hour in 2017, and they want me to ask Nalcor to compare the Muskrat Falls 2017 direct costs of 23.9 cents per kilowatt hour to the 14.3 cents per kilowatt hour often used by government and Nalcor, I guess, in speaking rates. I presume that's what the question is getting at.
MR. BENNETT:
A. And I think that, you know, in order to put that in its full context we need to look at the entire response to the RFI, so if we look at the cost associated with Muskrat Falls with the Labrador-Island transmission link with Holyrood, its upgrades, the associated thermal generating facilities, all of those costs are captured in our analysis, and you can see those on the record in a couple of different places. Some are confidential, but others are in the public domain so, for example, Exhibit 99 has all of the costs of both alternatives. There's a common database of all of that information, and that's where we derive our CPW analysis from, so I think the first and most important point is that all of the costs

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of both expansion plans are captured in our analysis. The second question then is what we use for analysis and what we use for comparison rather and providing context around those numbers, so if we look at an annual cash flow stream that extends over a period of 50 years, it's sometimes helpful to put that in context, so from an economic analysis perspective we can use various series of metrics in order to put that number into context so that we can understand it. So the 14.3 cents escalating price is equivalent to the costs that are contained in Exhibit 99, and it provides a useful reference when you're comparing, for example, to the escalating price of fuel at Holyrood, and the other costs that are associated with that. I mean, I think when we're talking about this and explaining the concept we can look at a cost series as an escalating price, as we might say in real terms, or we can look at it as a levelized unit price or LUEC, and we often use that price in the industry as well. Those are equivalent costs, and are used to put context and explanation around the actual specific

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costs, dollar numbers, that are used over the course of the 50-year study.
MR. JOHNSON:
Q. In terms of--does that conclude your answer to this particular question?
MR. BENNETT:
A. I think those are the key points, so for example on page 4, we have those incremental costs for Muskrat Falls and transmission, compared to the Isolated-Island thermal costs, expressed as LUEC. On the next page -
MR. JOHNSON:
Q. Okay, do you want to bring that up and just explain as we're going through, Mr. Bennett, so that -
MR. BENNETT:
A. So the second graph on page 4.
MR. MCNIVEN:
Q. Page 4 of 27?
MR. BENNETT:
A. Oh I'm sorry, page 4 of 7, maybe I have different paging--if we could go a little further down, I'm sorry, looks like I have an earlier--there we go. There's a levelized price. If you compare the Isolated

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alternative to the Muskrat Falls and Labrador-Island Transmission Link.

MR. JOHNSON:

Q. Okay, so your red line is your Isolated?

MR. BENNETT:

A. Yeah.

MR. JOHNSON:

Q. And your blue line is the Muskrat Falls and Labrador-Island Link, so just give us a narrative now so someone at home can understand this.

MR. BENNETT:

A. So now we've taken all of the costs over the 50 year study period and we have expressed it now as a constant amount paid in each year. So this is equivalent to the actual series of cashflows and the cash amounts that are incorporated in our 50 year study period.

MR. JOHNSON:

Q. Okay.

MR. BENNETT:

A. And if we go to the next slide, the next graph here, now we see the escalating price.

MR. JOHNSON:

Q. So just go back to your first graph for a

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second and I'll ask you a question now a customer would want to know. How come I should be happy about that?

MR. BENNETT:

A. Well the reason we should be happy about that is because the cost of the Muskrat Falls and Labrador-Island Link is substantially lower than the costs associated with the Isolated Link.

MR. JOHNSON:

Q. And put that in terms now with what you're seeing on the graph?

MR. BENNETT:

A. Well we see the LUEC for Muskrat Falls and LIL, the blue line, being a much lower annual amount than the red line, which is the equivalent expression of the cost associated with Holyrood, to use a fuel with pollution upgrades and a thermal generation associated with the Isolated plan.

CHAIRMAN:

Q. So that equals the two--in the cumulative sense, the two billion -

MR. BENNETT:

A. You could get back to the 2.2 billion dollar

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CPW preference.

CHAIRMAN:

Q. From the--that's a cumulative difference there that turns out to be, in terms of present value, the 2 billion dollars or whatever it is we're talking about.

MR. BENNETT:

A. That's right.

MR. JOHNSON:

Q. And similarly, and I guess Mr. Bennett, I guess--I'm not being facetious, but I'm asking you to really explain this and I know you guys are emersed into it, but you know, because people want to understand it.

MR. BENNETT:

A. Oh I understand, I understand, these are complex topics, I understand.

MR. JOHNSON:

Q. So if you go to the next graph -

MR. BENNETT:

A. Now we've expressed it in an escalating term, so we have an amount now that increases a percentage year over year, and if we look back in 2017 at the beginning of the blue curve on this line, you can see that there's

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approximately--it's sort of hard to read on this scale, but this is where the 143 dollars comes from. And now the 143 dollars escalates over time, and that's useful in comparison to our Isolated case, which has a substantial amount of fuel in it, so the bill for Holyrood will continue to escalate over time in the same manner.

MR. JOHNSON:

Q. Okay, and so again then, what makes us happy if someone is sitting at home about that graph?

MR. BENNETT:

A. The same point here, the gap between the blue line which is the Interconnected scenario and the red line, which is the Isolated scenario. And in both cases, just as in the same manner as the previous graph, the blue line is lower than the red line. So there's been lots of discussion about rates, there's been lots of discussion about the cost of energy, but at the end of the day, it is the actual cost flow to cost stream that's included in Exhibit 99 and the other related documents that we used to derive those long-term projections. And

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when, outside of this form when we hear people talking about the impact on consumer rates, wholesale rates, Newfoundland Power's rates, projected Domestic rates, all of that analysis comes from the database and is not derived directly from these analytical expressions. So these are really helpful to us in the industry, but from the consumer perspective, you have to look at the long-term rate projections that are used and are derived from the original cost numbers that are contained in our database.

MR. JOHNSON:

Q. So in terms of your red number being your Isolated escalating, the number in your lower graph, why--what's the narrative, why is that line going up in a fashion higher than the blue line?

MR. BENNETT:

A. Most fundamentally it's because the costs associated with that alternative are higher.

MR. JOHNSON:

Q. In plain English.

MR. BENNETT:

A. Well, we spend more on the Isolated

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alternative for fuel, for pollution controls, for replacement of Holyrood for the ongoing maintenance for the new thermal generating facilities than we do in the Interconnected scenario. This is another way of getting back to the 2.2 billion dollar CPW preference.

MR. JOHNSON:

Q. Okay, so we want to make sure we've answered this question, just to recap it then, ask Nalcor to compare the Muskrat Falls 2017 direct costs of 23.9 cents per kilowatt hour to the 14.3 cents per kilowatt hour often used by government and Nalcor. So answer that in a nice bow for this customer.

MR. GOUDIE:

A. Steve Goudie. Maybe I can try to help out here. If we move back to the first graph, if we could? No, that's the second graph, okay, this graph. So what this chart represents is the incremental costs of Muskrat Falls, plus Soldier's Pond delivered or--I'm sorry, Muskrat Falls plus transmission delivered as Soldier's Pond, that is the blue line. So these are the annual nominal costs of an incremental basis associated with bringing

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power from Labrador. It starts at 238 in 2017, it declines, then stabilizes and then turns up a little bit late in the period. So that's the incremental nominal unit costs that ultimately enters into our total revenue requirement, but this is not a rate that a consumer pays. This is our incremental cost of production, if we can sort of characterize it that way. What matters is what these costs are doing over time. On a weighted basis, when that moves into our total revenue requirement, this would only account for maybe 25 percent of our output, so these costs go into our total revenue requirement and get blended through to come up with the total revenue requirement on which rates are based.

MR. JOHNSON:

Q. So what other costs are they getting blended with then?

MR. GOUDIE:

A. They're getting blended with the existing system costs.

MR. JOHNSON:

Q. Okay, and tell the person at home what the existing system is.

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MR. GOUDIE:

A. The existing system would be our hydro electric base of Bay D'Espoir, Upper Salmon, Hynes Lake, et cetera. So we have two kind of cost buckets, we have our incremental cost bucket which is what this analysis represents; and then we have our existing cost bucket and that existing cost bucket accounts for maybe 75 percent of our output in the early years, but it's very low cost. So the higher incremental cost comes in and gets blended with the lower existing cost and that turns into our overall revenue requirement. Now the red line here represents the, comparatively, the annual thermal incremental costs associated with the Isolated-Island Option, so it's all the incremental, OMN, fuel and capital related to both Holyrood and our base load thermal plant going forward and we have to do that to make sure that we're comparing apples to apples because what matters to the customer is not the rate in 2017, what matters is how that rate changes over time, and that's the analysis we are obviously undertaking here in our CPW analysis. So this chart is

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actually very important because it conveys sort of the economic prize that we all receive once we get to where we're trying to get to, and that is that our incremental cost structure has now changed from an uncertain and increasing cost to a very stable and known cost. And this kind of cost structure will deliver declining real electricity prices to consumers over time. So once we move from this first chart, we want to say--well, we want to reflect on the fact that these nominal costs are changing each and every year, so how can we translate that into an economic message that we can sort of encapsulate what the message is into a single number, and that's why we calculate LUEC and that's why we calculate escalating supply crisis because we're trying to take the same information that's in this chart, which is changing each and every year, and we're trying to translate that back into a single number that we can kind of get our head around and make a fair comparison. So that's what we do when we move to chart No. 2, we take each of those two nominal costs over time and we translate them

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into single relevant economic numbers that open up what the message is. So the incremental costs associated with Muskrat Falls plus LIL delivered at Soldier's Pond across the planning period, would be in the order of 200 dollars per megawatt hours, levelized; whereas our incremental thermal would be in the order of 350, 360 dollars levelized. It is that differential that ultimately makes a huge contribution to the Interconnected Island preference of 2.2 billion. And then when we move to the next chart, we're just going to take the LUEC and we're going to restate that into an equivalent escalating price for a comparison against something like a Holyrood cost, which tends to escalate over time because of fuel. So all we're doing is that we're restating the same numbers in a different algebraic manner for different purposes, but they all have the same present value and they all mean the same at the end of the day in economic terms.

MR. JOHNSON:

Q. Okay.

CHAIRMAN:

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Q. So you sum it up and divide it by the number of years to get that straight line.

MR. GOUDIE:

A. The straight line is the present value of all the costs over the 50 year period, divided through by the present value of all the output. It's a division of those two present values, and that's just the way the algebra works, but they are identical. In present value these three different series for the two alternatives are identical.

MR. JOHNSON:

Q. So just come--if I could ask then regarding page 6 of 7, if we could look at column 5, this is the numerical representation of the nominal annual cost per megawatt hour and so I'm just going to start at the top of the line there, $239.00 in 2017, and then I'm going to pick, let's say 2037 and I think if I come across, that's $192.00 and that's the figure in 2010 dollars, I take it, is it?

MR. GOUDIE:

A. No, that is the nominal dollars of the day, so it's actually declining in nominal terms, in real terms it's declining at even a steeper

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rate. And that's the cost stability on our incremental costs that we're talking about. It's a change in the cost structure, a positive change in the cost structure.

MR. JOHNSON:

Q. Thank you. Some of these are very long commentaries and I have to tease a question out, so I have to put that in writing. There's a further question actually on CA-27, our revision one. I'm asked to direct you to page 6, column 2 for Muskrat Falls purchases and they're directing our attention to 2017 which is $166,054,000 for Muskrat Falls purchases and the question is, is this on a PPA basis?

MR. GOUDIE:

A. This is Steve Goudie. The purchase amount of 166 million in 2017 would be the nominal annual cost in that year.

MR. JOHNSON:

Q. And is that on a PPA basis?

MR. GOUDIE:

A. At that point it's not, but it ultimately feeds--all the nominal costs feed into a total and it's the total cost that would be present

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valued or put into CPW terms, but you have to build up your costs first in nominal dollars, which is what this is doing here.

MR. JOHNSON:

Q. Okay.

(10:15 a.m.)

MR. BENNETT:

A. If I could have a second?

MR. GOUDIE:

A. Perhaps I misunderstood your question. Do you want to try that again?

MR. JOHNSON:

Q. Yes, no problem. The question is in relation to that 166 million dollars that we see in column No. 2 for Muskrat Falls purchases, is this on a PPA basis; and then the follow-up question is if so, costs would be higher on a cost of service basis? And ask Nalcor to comment.

MR. GOUDIE:

A. The 166 million is derived from the PPA, it's basically the PPA price in that year, in nominal dollars, divided by the take for Newfoundland and Labrador Hydro. As I said before, it will build up into the total

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incremental costs and it will be present valued, so if that was a--the PPA again is focused on the rate of return on equity, it's not focused on net book value. So if we were moving to a cost of service framework, where we're going to revert back to net book value as to what really drives the rate, that 166 million would be at least doubled what it otherwise would be under PPA.

MR. JOHNSON:

Q. Okay. Well I guess just to follow up, why not just go cost of service? You have double, what's the--I guess, you know, I'd just like to flesh that out.

MR. BENNETT:

A. I think, you know, our rationale for using a PPA approach was laid out in Exhibit 36 and we think there are some good reasons for having that PPA approach, I mean, first of all you avoid that rate hit. The return for the investment is still recovered over the study period and the price schedule that shows up here in column 2 in general terms follows the same format and the same shape generally, but lower than the Isolated-Island scenario. So

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we think there are some very good reasons for using the PPA approach.

MR. JOHNSON:

Q. The next question has to do with interest during construction in relation to the Muskrat Falls generating facility. I think the background on that is initially that question was asked in CA-25, it was a customer question, an inquiry, and the question was is any interest during construction cost provided for in the cost projections for the Muskrat project and the answer said that "applicable interest during construction, IDC, is included in all in-service capital costs associated with both the Isolated-Island and Interconnected-Island alternatives. For all regulated assets, including the Labrador-Island Transmission Link, there is an allowance for funds used during construction, AFUDC, which includes costs for both the debt and equity used during the construction period based on the weighted cost of capital. The weighted cost of capital or WACC is determined by the capital structure assumed, i.e. 75 to 25 debt equity and the cost of debt and

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equity, i.e. 7.4 percent and 10 percent respectively." Then the answer continues, "The analysis for the Muskrat Falls generating facility is based on 100 percent equity with no debt. Since IDC only accrues against debt, no IDC is applicable." And I guess the question was if one--I guess what's behind the question is it doesn't appear likely that Muskrat Falls generating facility is going to be financed 100 percent with equity and what--it will take another capital structure to finance the project and I guess how would the "water on the beans" change in terms of CPW analysis if you were to assume a more likely financing scenario for the generating facility. I think that's the thrust of the question.

MR. GOUDIE:

A. Steve Goudie. We analyzed Muskrat Falls on 100 percent equity basis in DG2 for analytical purposes, there was really no clarity at the time on what the final financing arrangements would be, so we just analyzed it basically on a project basis, which is really quite common in many industries before the introduction of

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debt leverage. So once we put debt into Muskrat Falls, it doesn't necessary change the "water on the beans" at all. In fact, it could be favourable and likely will be favourable for consumers because the cost of debt will be less than the cost of equity. So as we leverage the project, the PPA price will reflect that, as long as we're focused on the return on equity--as long as we're focused on the return on equity, then the--as our hurdle, then the fall out will be on the PPA price.

MR. JOHNSON:

Q. Wouldn't be a bad way to conduct trials, just to have people give you the questions to ask. This one would be, "Dear Sir: Has Nalcor provided the following information"--and again, there might be issues of Terms of Reference, but we'll see. "Were there detailed negotiations with CF(L)Co and or Hydro Quebec for possible energy supply for the Interlink to the Island of Newfoundland."

MR. BENNETT:

A. Detailed negotiations with CF(L)Co. Certainly as far as CF(L)Co is concerned, you know, CF(L)Co's energy availability is something

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that we understand, it's a recall and it's the Twinco of the so called Twinco block which is available for iron ore development or industrial use in Western Labrador. So CF(L)Co in of itself has a limited supply of energy. And as far as Hydro Quebec is concerned, no, we have not undertaken detailed negotiations with Hydro Quebec.

O'REILLY, Q.C.:

Q. I think that's about as far as we can -

MR. JOHNSON:

Q. As far as you can go.

O'REILLY, Q.C.:

Q. - run that.

GREENE, Q.C.:

Q. Is Nalcor making an objection for the record? I just heard a consultant's question.

O'REILLY, Q.C.:

Q. Well what I heard the Consumer Advocate say is that he's getting these things here and we're trying to be discreet in raising them, I understand he's under some obligation to ask questions. I think the question that was put in general terms was responded to and I think he'd be pressed to go further than that, you

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know, there is some latitude and we're prepared to acknowledge that, but I think we're getting into an issue now that we shouldn't go down and if there's something in addition to that that the Consumer Advocate feels that is bearing on this and informs this process, then he can probably use the same method he suggested before as to put it in the form of a RFI and file it.

MR. JOHNSON:

Q. Well, and in point of fact the follow up was my follow up, not the customers and if they wanted to further email me and perhaps we could put it in the writing, if that be the case.

GREENE, Q.C.:

Q. No, I just wanted to make the process clear if there is a question asked by the Consumer Advocate it's for Nalcor to take an exception as to whether it is within or without the Terms of Reference, as opposed to counsel having a little discussion, it should be made for the record.

O'REILLY, Q.C.:

Q. Well I guess we will raise the objection to

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it.

MR. JOHNSON:

Q. Okay.

O'REILLY, Q.C.:

Q. I'm trying to be nice about this and not too stickily, you know, it is a review process, it's not a judicial process per se and so, you know, ordinarily if you were in probably a more defined setting, you'd be popping up and down and saying "objection" and so on. It is a review process; it's a little different. And Nalcor wants to be forthcoming in its answers, but at the same time it wants to stay focused on what the reference questions are.

GREENE, Q.C.:

Q. And there's no problem, that -

O'REILLY, Q.C.:

Q. Okay, well let's -

GREENE, Q.C.:

Q. The only thing was, there was a discussion between counsel which wasn't recorded for the record and if there was a decision made, it should be really on the record, that's my only point.

MR. JOHNSON:

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Q. Were diversion of exported recall energy to the Interlink considered?
MR. BENNETT:
A. So the currently exported energy from Churchill Falls is insufficient to meet our needs and there's a limited supply in the winter when we actually need the -- need firm capacity on the Island. The available recall capacity in the winter is about 80 megawatts.
MR. JOHNSON:
Q. The next--this is part C, were "SWAP" arrangements with Hydro Quebec re: Menihek output considered?
MR. BENNETT:
A. No, Menihek is an isolated generating facility next to Schefferville that has no transmission interconnection to the North American grid.
MR. JOHNSON:
Q. I think the next, Part D, is what will be the status of the Twin Falls Plant and transmission lines after reversion to CF(L)Co in 2014, and cannot moves be made to utilize them for input to the Interlink with regain of water supply as needed.
MR. BENNETT:

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A. I don't have specifics on Twin Falls, so I can't answer that question.
O'REILLY, Q.C.:
Q. I think that's outside the Terms of Reference, that's, you know--I raise an objection to that, if I can.
GREENE, Q.C.:
Q. And then, Mr. Johnson, your position on the objection?
MR. JOHNSON:
Q. I think it is probably outside.
GREENE, Q.C.:
Q. So there's no need for the panel to make a decision, I'm just--this is the type of process -
MR. JOHNSON:
Q. Yes, yes.
CHAIRMAN:
Q. I love it when lawyers argue.
GREENE, Q.C.:
Q. We're not arguing, we're just ensuring that the process is clear for all of the parties and for the process.
O'REILLY, Q.C.:
Q. Not always as pleasant.

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CHAIRMAN:
Q. I am sure, I know.
GREENE, Q.C.:
Q. This is definitely not argument, Mr. Chair.
(10:30 a.m.)
MR. JOHNSON:
Q. The last part (e) is how much spillage occurs at Upper Churchill at the present time and usually annually?
MR. BENNETT:
A. I don't have that number. Paul, do you -
MR. HUMPHRIES:
A. No, I don't have -
O'REILLY, Q.C.:
Q. It's the same issue and I raise an objection if I have to put it on the record.
GREENE, Q.C.:
Q. And the Consumer Advocate's position on this objection is, is it within or outside the Terms of Reference in your view?
MR. JOHNSON:
Q. It would appear to be outside, I have to concur, but again I wanted to put it there.
CHAIRMAN:
Q. But I think it's fair to Consumer Advocate, I

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mean, for the question was asked by a concerned citizen.
MR. JOHNSON:
Q. Yes, yeah.
CHAIRMAN:
Q. And it seems to me that it should be read into the public record so that at least you would have done your job and acknowledged the fact that this is a question that you asked.
O'REILLY, Q.C.:
Q. That's right.
CHAIRMAN:
Q. And if there's an objection, of course, that's--you know, and it is deemed to be outside the Terms of Reference, well duty has been done, I guess.
GREENE, Q.C.:
Q. And in a situation where there may be disagreement as to whether it is within or without the Terms of Reference, that is when there will be the opportunity for argument with Nalcor, the Consumer Advocate and Board Counsel expressing a view on that issue.
MR. JOHNSON:
Q. A question concerning--this is the question:

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"There is public concern that the 824 megawatt Muskrat Falls capacity may have reduced capacity of only 575 megawatts for the winter peak from January to March on the Island (cause 500 megawatts will be needed for Holyrood, 165 megawatts for Nova Scotia), leaving an estimated 150 megawatts for new demand. Ask Nalcor for pubic comment."

MR. BENNETT:

A. Well as far as production in Muskrat Falls goes, certainly Muskrat and Churchill Falls operate under the terms of--or will operate rather under the terms of a water management agreement that has been established by the Board, so when we look at the production between Muskrat and Churchill Falls, there will be available capacity on peak through the operation of that water management agreement.

MR. JOHNSON:

Q. The second question is: does Nalcor have any recent updated hydrology studies to confirm that Muskrat Falls can produce at 824 megawatts for the winter peak?

MR. BENNETT:

A. We have a long history of hydrology studies on

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Muskrat Falls. Records go back over 50 years. So, we're comfortable with the energy production at Muskrat.

MR. JOHNSON:

Q. The next question is: for the winter peak of 2018, how much Muskrat Falls 824 megawatt capacity will be available?

MR. BENNETT:

A. We expect to have the capacity necessary for Muskrat Falls to meet the winter peak in 2018.

MR. JOHNSON:

Q. The next question is: if there are power outages, how will these be apportioned between Newfoundland and Nova Scotia? Again, that's a -- we're assuming for the purposes of this reference that there is no link. But there was some discussion of it yesterday.

GREENE, Q.C.:

Q. Does Nalcor take objection to the question?

O'REILLY, Q.C.:

Q. I think that that's outside -- it's outside the terms. It's not -- it doesn't inform -- again, it doesn't inform this process, you know, how the distribution of power, who's going to get the recall, primary call on that.

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That does not inform this process and I'd raise an objection to that.

MR. JOHNSON:

Q. Well, I certainly can't take the position that we are here in this reference assuming that the link is part of the reference, but you know, there was some discussion about it and I guess from a technical aspect, I may be wrong, but someone may have tuned in yesterday and said "well, you know, there was a bit of discussion about it yesterday." So, pretty much all I can say about the point.

O'REILLY, Q.C.:

Q. I mean, you know, I guess what you're prodding into here is a subject that is the subject of ongoing negotiations between parties that are not part of this reference question and I can't see how this could be -- really, I can't see how this could be informative of this process.

GREENE, Q.C.:

Q. One of the challenges with this particular question is trying -- is the proper interpretation of the terms of reference that were given to the Board by the government.

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The Terms of Reference exclude consideration of the monetization of any excess power. As mentioned in the Terms of Reference, certain issues were excluded from consideration by the Board. One of those issues was the Maritime link and the arrangements with Emera. While there was discussion yesterday, it was brought forward by Nalcor as to whether that is within or without the Terms of Reference and it was the reference to the Maritime link with respect to reliability. However, Nalcor's position is that the Maritime link is not required to adequately address reliability, so while they did refer to it, it is not necessary for the Board's consideration and in fact would be outside the Terms of Reference. So with respect to this particular question, my opinion would be that it would be outside the Terms of Reference as well.

I don't know if the Panel needs to take any additional time to consider before making their decisions or their view.

CHAIRMAN:

Q. No, I don't think so. We can carry on and we might discuss it, but we're satisfied with it,

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you know.
O'REILLY, Q.C.:
Q. Well, I guess the question will be deferred until there's a ruling.
GREENE, Q.C.:
Q. Yes.
MR. JOHNSON:
Q. Another question: Nalcor advised today, that being yesterday, that IOC expansion may require 500 megawatts of power. Muskrat Falls has 824 megawatts of capacity, 165 megawatts for Nova Scotia, being 159 megawatts left for the island of Newfoundland over the in-feed. That would amount to transmission line in-service cost of 2.5 billion for 159 megawatts, question mark. Ask Nalcor to comment on that scenario.
MR. BENNETT:
A. I don't see that as a viable scenario. First of all, we don't have a firm request from IOC and I think it's fair to say that if customers on the island part of the system are paying the cost associated with Muskrat Falls and the Labrador-Island transmission link, then they're absolutely entitled to receive the

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energy that's associated with the assets they're paying for.
MR. JOHNSON:
Q. I think you answered the second question already. When does IOC need the 500 megawatts for expansion?
MR. BENNETT:
A. Yeah, in general terms, they're following a Decision Gate process the same way that we do and they have not put forward a firm request for energy.
MR. JOHNSON:
Q. Third question: Why not dedicate Muskrat Falls solely to Labrador power requirements if IOC needs 500 megawatts? It's answered in the previous question.
Nalcor advised that the transmission line losses would be the maximum peak of ten percent when Muskrat Falls is operated at peak capacity. This will impact the ability of Muskrat Falls to meet the island winter peak power demands. Can Nalcor comment?
MR. BENNETT:
A. I'm not sure how it affects it. So, can you just restate that question, please?

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MR. JOHNSON:
Q. Nalcor advised that the transmission losses would be at the maximum peak of ten percent when Muskrat Falls is operated at peak capacity. This will impact the ability of Muskrat Falls to meet the island winter peak power demands. Can Nalcor comment on that?
MR. HUMPHRIES:
A. The existing analysis up to DG2 assumes that the peak losses could be at the nine or ten percent range, so the expansion plan already compensates for that ability to supply the load. It's just not Muskrat Falls. It's the total resource in Labrador and on the island.
MR. JOHNSON:
Q. That does that. There might be some in there that are embedded that I'll put in writing. They look like they're a bit more involved than what can be handled like that. So those are my questions of the Panel. Thank you very much.
CHAIRMAN:
Q. So I guess we'll take a break now. No?
O'REILLY, Q.C.:
Q. I don't know. Does the Panel have questions?

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I'm just wondering if we can finish with the Panel because -- I don't know. If you wish to take a break, that's fine with us, but if there's -
CHAIRMAN:
Q. I can keep going all day, but I mean, I got chastised the day before yesterday.
O'REILLY, Q.C.:
Q. Okay. Well, alright, we'll take a break.
GREENE, Q.C.:
Q. What Mr. O'Reilly is wondering is how long the Commissioners might be with the Panel, whether the Panel could be finished before the coffee break. It would assist in them moving forward to the next panel.
CHAIRMAN:
Q. Well, I got a few questions. I won't be very long.
GREENE, Q.C.:
Q. So that's -- the idea would be -
O'REILLY, Q.C.:
Q. There's two things. There's the Board's, the Commission's questions and also there's a few undertakings that we can deal with while the panel is here. So I thought if we could get

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that part and if you're not going to be long -
CHAIRMAN:
Q. No, no.
O'REILLY, Q.C.:
Q. - we can deal with that and then we can dismiss the panel, if that's satisfactory.
CHAIRMAN:
Q. Okay. Is that acceptable to all parties?
GREENE, Q.C.:
Q. Yes. Yes, Mr. Chair.
CHAIRMAN:
Q. So it's up to us now. So, Commissioner Newman, have you got any questions?
COMMISSIONER NEWMAN:
Q. No questions, thank you.
COMMISSIONER OXFORD:
Q. No, sir, no questions.
CHAIRMAN:
Q. Madame?
VICE-CHAIR WHALEN:
Q. I just have a -- I had lots of questions. I think most of them have been covered. I have one question from something you, Mr. Bennett, just said about in reference to a -- in your response to a question from Mr. Johnson with

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reference to IOC and you don't have a firm power commitment or request from IOC of 500 megawatts, I think was the number. What does Nalcor or Hydro do when you get that request?
MR. BENNETT:
A. So once we see that request, then we'll have to look at timing. We'll have to compare the size of that request compared to our various resources. If we look at Muskrat Falls in the short term, it has supply. I guess in very general terms, that would go into a generation expansion plan and we'll have to come up with a solution to meet that requirement.
VICE-CHAIR WHALEN:
Q. So what other -- are there any other options or alternatives in Labrador for to meet that significant load?
MR. BENNETT:
A. There are other potential developments in Labrador.
VICE-CHAIR WHALEN:
Q. Gull Island for example.
MR. BENNETT:
A. Gull Island being one. The others would be further down the line in terms of timing

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because of the environmental assessment process. Ultimately, we may have to find we have to go to the market in order to meet a short term need or use a thermal alternative. Those are the general suite of alternatives. Mr. Humphries, I don't know if you -
MR. HUMPHRIES:
A. No, that would be -- and again, the important factor is the size and the time. That would, you know, whether it's 100 megawatts or 500 megawatts makes a difference, and the timing, and to date, we do not have a firm request or even a firm idea of where this may settle out and once we get that, then we will start through a process to address how we would meet that request.
VICE-CHAIR WHALEN:
Q. I had another question and it relates to the probabilistic assessment, reliability assessment discussion you were having with Mr. Johnson yesterday and Ms. Greene and Mr. Johnson this morning and you were talking -- I wrote down your comment. I can't find the transcript reference. That the results of such an assessment could have significant --

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and I think your word was significant implications for ratepayers.
MR. HUMPHRIES:
A. They would have significant impact on the way we currently -- our current practices, which ultimately could have an impact on ratepayers, yes.
(10:45 a.m.)
VICE-CHAIR WHALEN:
Q. Could you expand on what the impacts specifically might be?
MR. HUMPHRIES:
A. Well, like in the -- when we start to introduce these new, I would call new factors into the overall reliability assessment, like the cost, the societal cost of outages, customer outages and those types of things, and that if our standard increases to a level that we have to incorporate them, we could end up having to add additional capacity, generating capacity, transmission capacity to live within these new constraints and that could introduce significant costs given the fact that we are a small rate base and, you know, the ability to pay and the desire to pay

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is not -- it has a larger impact than it would in a larger jurisdiction where there's a bigger rate base to spread these costs over.

VICE-CHAIR WHALEN:

Q. Okay. That's fine. I think that's all. Thank you very much, Panel. It's helpful.

CHAIRMAN:

Q. I had a couple of questions. I would have put them to Mr. Martin if he was here, but I think, Mr. Bennett, you can fill the breach admirably.

MR. BENNETT:

A. I'll try.

CHAIRMAN:

Q. On the issue of economic benefit, Mr. Martin I think said that because with respect to Muskrat Falls that we would be spending this money immediately in the community that there was a greater economic benefit as opposed to doing an Isolated island scenario, and I mean, really we will not know whether or not this project or the Isolated island is a good project except over an extended period of time, wouldn't you agree?

MR. BENNETT:

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A. Yes, I would agree with that. You know, we're looking at the beginning of that expansion plan and the project as it unfolds.

CHAIRMAN:

Q. As long as the chosen alternative remains over time the least cost then there is an economic benefit?

MR. BENNETT:

A. Yes, and I think maybe when Mr. Martin was speaking of that, he was looking at the cost preference as well as the benefits to the economy, just in general, from the large scale project that we'd be undertaking.

CHAIRMAN:

Q. Well, that's my point. I mean, there's no benefit to the economy if you don't produce an asset that has economic value over time. We can build a tunnel to Bell Island tomorrow and it would be great for the work, but it won't produce any economic value.

MR. BENNETT:

A. Other than the benefit to the economy from the construction, labour, the tax income, the purchases that are associated with the project itself.

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CHAIRMAN:

Q. Yeah, but the assumption there is always that there's other alternatives you can spend that money on that may produce some value.

MR. BENNETT:

A. And you're right, but in this case, most of the value in the Isolated case is gone to imported oil where we don't see that benefit in our economy.

CHAIRMAN:

Q. And I also got a question on this business of clean energy and I guess the question is why do you say hydro is clean energy? I think you said that the avoided CO2 emissions would be 866 thousand tons. Is that the number that you guys used?

MR. BENNETT:

A. There is some large numbers.

CHAIRMAN:

Q. Yeah.

MR. BENNETT:

A. Yes. I think for Holyrood the number is in that -

CHAIRMAN:

Q. The not burning a fossil fuel generates carbon

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savings of 866 thousand tons of CO2?

MR. BENNETT:

A. Right, and on a larger scale basis, if we were talking about the export energy and the displacement of thermal generation in other markets, the numbers would be much bigger than that.

CHAIRMAN:

Q. But it's at 866 thousand tons, and I mean, I don't have no -- I have no idea what a ton of carbon looks like. Do you? I mean, it's just so abstract to me, it just -- I mean, anyway.

MR. BENNETT:

A. Just maybe to put it in perspective, a typical vehicle on the road is about five tons per year. So that's sort of some insight into the magnitude.

CHAIRMAN:

Q. But is that a net figure?

MR. BENNETT:

A. Oh yes, that's a net number.

CHAIRMAN:

Q. So you've calculated in your -- coming up with your 866 thousand tons, you've calculated the carbon content, the fossil fuel content in the

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construction of the project?
MR. BENNETT:
A. Oh yes.
CHAIRMAN:
Q. All the materials that are bought?
MR. BENNETT:
A. Yes, we have. So there's a process for doing that. The Intergovernmental Panel on Climate Change has identified a methodology for doing that and we look at both the emissions during construction, as well as the greenhouse gas emissions from the reservoir itself over time.
CHAIRMAN:
Q. And the net is 866?
MR. BENNETT:
A. That's right, and that's just for Newfoundland, for the Newfoundland system. In Nova Scotia, there would be about another one million tons from their displacement.
CHAIRMAN:
Q. And why is that significant? I mean, 866 thousand is a big number, but is it really big?
MR. BENNETT:
A. Well, Canada's greenhouse gas emissions in

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approximate numbers are in the order of 700 million tons. So, I think, from -- you know, from all of our perspectives, there's a collective desire to reduce our carbon footprint, as a society, to reduce our greenhouse gas emissions. So, I think over -
CHAIRMAN:
Q. Well, that's -- there's arguments about that.
MR. BENNETT:
A. There's a lot that we all have to do.
CHAIRMAN:
Q. But what percentage does -- what percentage are Newfoundland's emissions as a percentage of Canadian emissions?
MR. BENNETT:
A. They're slightly less than two percent. I'll confirm these numbers for you.
CHAIRMAN:
Q. No, that's the number I got, so we agree on that.
MR. BENNETT:
A. Okay. Yeah, my recollection is that we emit, in Newfoundland and Labrador, about ten megatons per year.
CHAIRMAN:

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Q. And what's the percentage of the Canadian emissions as the percentage of world emissions?
MR. BENNETT:
A. That number I don't have. On a per capita basis, we're among the highest per capita greenhouse gas emitters in the world.
CHAIRMAN:
Q. Yes, but we're not a big population.
MR. BENNETT:
A. We're not a big population, you're right.
CHAIRMAN:
Q. I have read that Canada's CO2 emissions are two percent of the world total.
MR. BENNETT:
A. That wouldn't surprise me. I would tend to agree with that number.
CHAIRMAN:
Q. Are you aware that, for instance, that the brick countries -- you know what I'm talking about, Brazil?
MR. BENNETT:
A. Yes, I do.
CHAIRMAN:
Q. They refuse to have any -- contemplate any

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reduction in the use of fossil fuels in their economic development.
MR. BENNETT:
A. I think that's a concern. They're a big block of population.
CHAIRMAN:
Q. They said no.
MR. BENNETT:
A. And so far they've said no.
CHAIRMAN:
Q. And are you aware that since 1998, I think I read that CO2 emissions have risen by, I think the number is some 28 percent. Have you come across that number?
MR. BENNETT:
A. That rings a bell, and certainly the questions that we all have to -- you know, as part of our global society, we're going to have to consider the consequences. I think in looking the other way, the Intergovernmental Panel on Climate Change from the UN have said that we collectively have to find a way by 2050 to reduce our greenhouse gas emission substantially and that's a big challenge and I would agree that everybody on the planet can

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look at this and say "well, I'm only a small piece" and you know, this is a -- you know, from a global perspective, I'd agree this is a very complicated topic.

CHAIRMAN:

Q. And you don't think whatever Canada does or Newfoundland does is irrelevant in that process?

MR. BENNETT:

A. Well, I think it's helpful in two senses. I think we can say, first of all, that we're doing our share. And secondly, we're setting a good example for the rest of the world. So, I would look at it that way and say I think everybody -

CHAIRMAN:

Q. And you actually believe the rest of the world will care?

MR. BENNETT:

A. Well, that's -- I don't know if I can answer that one. It's a concern. There's no question.

CHAIRMAN:

Q. You think the Chinese would be concerned, "oh, gee, Canada is stepping up to the plate. We

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got to follow"?

MR. BENNETT:

A. Well, I hear you.

CHAIRMAN:

Q. And I asked the -- you're going to get the number on the CO2, you know, the cost of CO2 per -- and you think Newfoundlanders would be willing to pay carbon tax in their electricity rates because they want to be good world citizens? You think that's a viable political alternative?

MR. BENNETT:

A. Well, I think in the scenario that we're moving forward with, we're proposing to move forward with, that being the Interconnected scenario, we avoid that debate.

CHAIRMAN:

Q. Yeah, yeah, that's true.

O'REILLY, Q.C.:

Q. Mr. Chairman, I have those -- I have that number. I think you asked for that yesterday.

CHAIRMAN:

Q. Yeah.

O'REILLY, Q.C.:

Q. And we have the cost and I can give it to you

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now, while you're -

CHAIRMAN:

Q. Sure. I'd be interested.

O'REILLY, Q.C.:

Q. - while you're in mid -

CHAIRMAN:

Q. In mid flight or mid fancy.

O'REILLY, Q.C.:

Q. - mid flight there, and I can produce that and actually, Steve, you need to speak to it. You can speak to it.

MR. GOUDIE:

A. If we have to, yeah, sure.

O'REILLY, Q.C.:

Q. So I can make those available here. So I hope we can now check off one of the undertakings. And Mr. Goudie can speak to that, if -

CHAIRMAN:

Q. I'm sorry?

O'REILLY, Q.C.:

Q. Mr. Goudie can speak to that if you want to.

CHAIRMAN:

Q. Commissioner Oxford said six bucks a month. Where am I looking for that?

MR. GOUDIE:

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A. Yes, Mr. Chairman, if you look to line 17.

CHAIRMAN:

Q. It was too big. I was looking at the small print.

MR. GOUDIE:

A. Yeah. Well, at line one, you'll see that the input there is 24 dollars a ton. So, we took that and increased Hydro's revenue requirement and then followed through the calculations as in PUB-5, which take revenue requirement through to wholesale and retail rates and that would be our preliminary estimate. Given 24 dollars a ton for CO2, it would be approximately six dollars per month per residential customer.

CHAIRMAN:

Q. So if we had a carbon tax in Newfoundland with the Isolated island, it would cost consumers about 70 bucks a year, assuming the tax was a reality?

MR. GOUDIE:

A. 24, yes, that's correct.

CHAIRMAN:

Q. And Mr. Bennett, you're aware that Canada has withdrawn from Kyoto?

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MR. BENNETT:
A. Yes, they have. You're right.
CHAIRMAN:
Q. And you're aware that there's no possibility, there's no -- it doesn't look likely that there's going to be any international agreement on carbon taxation?
MR. BENNETT:
A. You're right, it's a global challenge.
CHAIRMAN:
Q. And that Mr. Harper has said that they will follow the -- Canada will follow the US example?
MR. BENNETT:
A. That's right.
CHAIRMAN:
Q. And you're aware that the House of Representatives for sure, certainly have turned thumbs down on the Waxman -- is it Waxman goes first, Waxman Markey Act?
MR. BENNETT:
A. Waxman Markey, that's right.
CHAIRMAN:
Q. So that's dead on arrival in the House of Representatives.

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MR. BENNETT:
A. Yes, I -
CHAIRMAN:
Q. And you still believe that carbon taxation is a possibility?
MR. BENNETT:
A. No, what I said was that the Federal government has taken steps on coal-fired generating facilities. So they have moved forward with legislation. Now, and I agree with everything you've said, those are all absolutely correct. I'm also concerned with the science and I'm also concerned with the long term implications. So, I just -- we recognize there's a challenge. We didn't include it in our economics, but I think both Navigant and MHI identified this as a potential risk to the Isolated scenario. I agree with you that this is complex question and there -
CHAIRMAN:
Q. When you say concerned with the science, what do you mean?
MR. BENNETT:
A. Well, I think that in the long term, you know,

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the question, the science behind greenhouse gas, the connection between emissions and global warming I think is a long term challenge that we're going to have to come to grips with, but that's a whole -- that's a whole different topic, you know, for a different venue, I think, unless you'd like to go there.
CHAIRMAN:
Q. No, I don't want to take up -- I'd sure like to argue with you about it, but I'm not going to do it here. But, I mean, I just read the other day, China has got plans now for 100 coal-fired plants.
MR. BENNETT:
A. Right, they build coal plants like, you know, like a lot of utilities install distribution systems.
CHAIRMAN:
Q. Coal is not going away anytime soon. I think the EIA said coal use is probably going to rise.
MR. BENNETT:
A. It's a challenge.
CHAIRMAN:

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Q. Are you aware that, like for instance, I have also read you can't make steel without using coal. So no matter what you do with CO2, you're still going to have some. You got to make coal to make steel.
MR. BENNETT:
A. Coal, cement, aluminum are all big industrial challenges.
(11:00 a.m.)
CHAIRMAN:
Q. And big components in dams. Now, let's -- just a couple of questions on CO2, which is a real puzzle for me. I mean, you and most people link together CO2 -- you link SO2, NO 2 and CO and soot all together. Now I agree that -- I mean, there's no doubt in this room or anywhere, if you know anything about it, that SO2, NO2 and CO, even though there's only one little difference between CO2 and CO, CO and soot are bad. They're not nice. They make people sick. Are you aware of people showing up at the Health Science with CO 2 problems?
MR. BENNETT:
A. No, I'm not.

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CHAIRMAN:
Q. Do you know anywhere in the world where people have gotten sick from CO2?
MR. BENNETT:
A. Not from atmospheric CO2, no, I would agree with you there. I'm not aware of any situation.
CHAIRMAN:
Q. Do you know what -- I mean, toxicologists say that it's not the substance, it's the dose that matters. Do you have any idea what the -- I don't, but do you have any idea what a toxic dose of CO2 would be?
MR. BENNETT:
A. No, I don't.
CHAIRMAN:
Q. Do you know what PPN we are at now with respect to CO2 in the atmosphere? What number do you use?
MR. BENNETT:
A. My recollection is that number is just north or just approximately 200 parts per million.
CHAIRMAN:
Q. I think it -- I thought it was closer to 400.
MR. BENNETT:

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A. I think that's where we're projected to be going.
CHAIRMAN:
Q. Oh, that's where we're projected to be going?
MR. BENNETT:
A. I think so. I can validate that. That's an easy one to look up to confirm for you.
CHAIRMAN:
Q. Have you ever looked at climate history? Have you ever looked at what some of these paleoclimatologists say about the CO2 levels?
MR. BENNETT:
A. Certainly in previous points in our history, I would agree that CO2 levels have been much higher than they are today.
CHAIRMAN:
Q. I read one article where it said that CO2 levels during mankind's time on earth were 50 times higher than they are now with no threat to life.
MR. BENNETT:
A. I haven't seen that number.
CHAIRMAN:
Q. So we don't -- you can't really say that CO2 is a pollutant because we got no evidence.

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MR. BENNETT:
A. And at this point, we've never put forward CO2 as that issue, and as I said, we haven't included it in our economic analysis.
CHAIRMAN:
Q. I'm just saying if there's no evidence of it being a problem, why is it necessary to tax it or control it? I mean, I don't want to -- you know, am I getting -
O'REILLY, Q.C.:
Q. I guess that's -
CHAIRMAN:
Q. - am I running afoul of you, Mr. O'Reilly? Do you want to do that, you know?
O'REILLY, Q.C.:
Q. Well, this is very -- you know, very interesting. I guess, I -
CHAIRMAN:
Q. Anyway, alright.
O'REILLY, Q.C.:
Q. - I just think that we might be -- I mean, the -- if there are going to be policy considerations for regulating carbon emissions, I think it's a little bit beyond this Panel to argue with them.

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CHAIRMAN:
Q. Okay.
O'REILLY, Q.C.:
Q. But I'm very cognizant of the fact that when I take an objection, I'm taking the objection to the person who's making a ruling on it, so I got to take -- the chances of raising a successful objection in this context is very, very low. It's probably plus 50, minus 30 and probably getting broader.
CHAIRMAN:
Q. Let me assure you, I wouldn't under estimate you. Anyway, I just -- I'm just -- all I can say is I just find the whole thing -- I'm bemused or I'm perplexed. I don't understand what is going on and I mean, we're in somewhat of a judicial setting. I just refer to the Supreme Court of the United States and the unanimous decision which said that this whole issue should be subject to an awful lot more debate before any major policy decisions are made that have cost implications for society. I read 272 billion dollars been wasted so far in Europe. Anyway, I'll stand chastised by Mr. O'Reilly, so I'll carry on.

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The rank of wind in the Isolated island, would you -- if I could ask you, is it important, somewhat or not very important?

MR. HUMPHRIES:

A. In the Isolated island?

CHAIRMAN:

Q. Yes.

MR. HUMPHRIES:

A. We feel wind is important as a resource. It is limited in the -- going to be limited in the Isolated island case and we will continue, I guess, if we stay Isolated, to look at opportunities to integrate as much wind as we can, when we can, into that system and again, in the Interconnected case, there are huge opportunities for wind because of the fact that we have those connections. There are the potential to integrate hundreds of megawatts of wind.

CHAIRMAN:

Q. Wow. I mean, have you looked at wind in other jurisdictions?

MR. HUMPHRIES:

A. We've looked at it in other jurisdictions and we have a limited amount in our current

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jurisdiction.

CHAIRMAN:

Q. Pardon?

MR. HUMPHRIES:

A. We have wind in our current jurisdiction.

CHAIRMAN:

Q. No, but I mean, have you looked at wind -- like I looked at wind in Germany, in Denmark, in Spain, in Texas, in Ontario, and again, I remain perplexed why people consider it first of all as a source of power because it's not really power. It's energy, but it's not power.

MR. HUMPHRIES:

A. I agree and that is one of the concerns particularly in our Isolated situation. It is not capacity, but it is energy and we do have an abundance of it and the capacity factors of the developments we do have in Newfoundland are attractive. They are in excess of 40 percent. The two facilities that we have right now, the small ones, they work quite well.

CHAIRMAN:

Q. They're the highest in the world.

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MR. HUMPHRIES:

A. Close to it.

CHAIRMAN:

Q. Well, there's no -- I haven't come across a capacity factor higher than 30 percent.

MR. HUMPHRIES:

A. That's more the norm, but there are numerous sites in Newfoundland and Labrador.

CHAIRMAN:

Q. In Texas, which got 3400 wind farms, ERCOT rates Texas reliability at less than ten percent. In Germany, it's the same. In France or in England, it's the same. Anyway, I'm having some problems with -- anyway. Are you aware of -- like I saw a British study of the British grid with respect to wind integration and the title of the -- I got the title of the book in my office. Anyway, this guy is a grid engineer. That would be -- the closest would be you?

MR. HUMPHRIES:

A. That's correct, yes.

CHAIRMAN:

Q. And his study showed that once you get beyond -- I think he used a figure of seven to eight

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percent of wind integration into your grid, certainly no higher than ten percent, it introduces tremendous supply instabilities and can cause blackouts.

MR. HUMPHRIES:

A. That's correct.

CHAIRMAN:

Q. And he expects anytime now the British grid to crash because of the -- they got close to 4,000 turbines operating now too.

MR. HUMPHRIES:

A. It's very much a function of the size of the grid and in our Isolated road, we are a very small grid and that is a concern.

CHAIRMAN:

Q. But why do you think if you went with Muskrat Falls you could introduce large amounts of wind then if you got this ten percent problem?

MR. HUMPHRIES:

A. Well, we're part of a bigger grid now. We're part of the North American grid. So it is an attractive North American solution because of our high capacity factors. Wind in Newfoundland will be more attractive than wind in the other jurisdictions.

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CHAIRMAN:
Q. Anyway, I don't want to -- I mean, I'd like to -- again, I could argue the point, but we'll -- I guess that's -- just check my notes now to see. At Holyrood, with respect to the good problem and the other stuff, how many events have you had in the past five years? Anybody know?
MR. HUMPHRIES:
A. I don't have that number right now, but there's been a marked reduction in the number of complaints from the public.
CHAIRMAN:
Q. Because Holyrood really runs during the winter months, doesn't it?
MR. HUMPHRIES:
A. Predominantly, yes.
CHAIRMAN:
Q. Winter peak.
MR. HUMPHRIES:
A. Yes.
CHAIRMAN:
Q. I guess that comes back to the wind thing. I mean, what's the good of wind in the summer, if you're not using Holyrood?

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MR. HUMPHRIES:
A. Yes, that is another fact and when you have Hydro resources, you have to balance the wind with the Hydro and obviously if you spill water to generate this wind, that's not good either.
CHAIRMAN:
Q. No. Are you aware of the Energy Information Agency's -- they did a calculation on what it costs to generate a megawatt of wind in the United States. Their figure was 119 dollars. Do you have any numbers on to create a megawatt of wind? What are you guys using?
MR. HUMPHRIES:
A. It's in that range, yes.
CHAIRMAN:
Q. Versus say what's a megawatt of Muskrat going to cost?
MR. GOUDIE:
A. 76 dollars.
MR. HUMPHRIES:
A. 76 dollars.
CHAIRMAN:
Q. So we got a 45 dollar difference. So wind is pretty expensive, isn't it?

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MR. HUMPHRIES:
A. It's not cheap, but it's -
CHAIRMAN:
Q. So what's the good of it?
MR. HUMPHRIES:
A. In the -
CHAIRMAN:
Q. I mean, I got an open mind. I mean, I have no preconceived notions, but I just ask myself questions and I don't get a chance often to talk to experts.
MR. HUMPHRIES:
A. From an energy perspective, from the global sense and the North American sense, it still fits in a range that is an acceptable option. There are issues with capacity and all those factors, but there's still a place for wind in an overall balanced portfolio of resource.
CHAIRMAN:
Q. Well, in terms of the concept that I like to think about, power density, I mean, wind is not even power, but that's another -- do you agree with me on that? Mr. Bennett is shaking his head and saying yes.
MR. HUMPHRIES:

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A. From the overall -
CHAIRMAN:
Q. Well, wind is not power. I mean, when we think of power, we turn the switch on, the energy is there.
MR. HUMPHRIES:
A. That's right.
CHAIRMAN:
Q. When you start your car, I mean, you only use your car an hour a day, but boy, that engine got a reliability of what, 100 percent? How often does your car breakdown? Wind, you don't know whether wind is going to be there. It could be there and it could not be. It could go up. It could go down.
MR. HUMPHRIES:
A. That's right.
CHAIRMAN:
Q. You got problems. You got parameters on operating. I mean, you need ranges between six miles per hour and 40, I think. Once you get beyond 40 you got to shut her down because they're liable to go off their -- well, they crash and they break.
MR. HUMPHRIES:

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A. That's right. Wind, as a technology stand alone, is not a reliable power source.

CHAIRMAN:

Q. And you're going to put windmills in Labrador in that climate? Wow. Anyway, I guess I've digressed or wasted enough of your time. Weighted average cost of capital, that's one of the things interests me. 75/25 you're saying for -- wouldn't you -- if you had a higher debt ratio and a lower equity ratio, wouldn't that make your rates cheaper? I mean, can't you guys finance this at a higher -- aside from -- I guess you got a government order to have an equity base of 25, have you?

MR. GOUDIE:

A. It's Steve Goudie. I think the government policy directive has to do with the return on equity that we're entitled to earn and that would be in the order of what Newfoundland Power receives, if not equal to it. On capital structure, to the extent that debt is cheaper than equity, that's the whole point of leverage, you will minimize your -- you'll minimize your selling price. But we have a -- you know, you got to take into account the

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sort of financial strength of the company too. So I think our debt equity target right now, I think our actual target for Hydro is around 75/25 as we speak.

CHAIRMAN:

Q. But I mean, you -- Nalcor/Hydro has a government guarantee, so you guys can't go bust unless the government goes bust, and I guess my point is if you decided to increase your debt ratio say to 95 percent and you only had five percent equity, I mean, that wouldn't make the company any riskier in the markets because of the government guarantee. Would that lower rates to consumers? Because that's the only thing that concerns me in this whole exercise. I mean, all of us, what's the best deal for the ratepayers of Newfoundland over the period that we're talking? How do we get the best deal for the people? That's the only thing I'm interested in. Would it -- as one of the factors, wouldn't it be a 95/5 versus 75/25?

MR. GOUDIE:

A. Well, Nalcor will be financing Muskrat Falls, not Newfoundland and Labrador Hydro, so Nalcor

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has to go to the marketplace and the financial strength for Muskrat Falls has to be there. Otherwise, people will not be interested in buying -- in financing it.

CHAIRMAN:

Q. Yes, but it's backed by the -- I mean, it's backed by the Province though, isn't it? It's not like Fortis. I mean, Fortis is a stand alone company. It has no guarantees beyond the equity base and its fiscal integrity. I mean, Nalcor is more like -- you know, it's more like a -- I shouldn't say a bank, that's unfair to Nalcor, but I mean, you know, Nalcor can get bailed out if he runs into problems because it's a government entity.

MR. GOUDIE:

A. The debt guarantee fee applies to Newfoundland and Labrador Hydro capital.

CHAIRMAN:

Q. Yeah, but does it -- it doesn't matter then you're saying, Mr. Goudie, that it's owned by the government, guaranteed by them? Does it make any difference in terms of a potential investment?

MR. GOUDIE:

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Q. Well, I'm sure it does make a difference, but at the same time, if you're trying to interest people in the capital markets in your project, which we will be, in terms of Muskrat Falls investment itself, the capital structure of that company has to be solid and it can't be over leveraged.

CHAIRMAN:

Q. So you don't think we could finance at 95/5 for instance? You don't think anybody -- a bond holder would find 95 percent attractive?

MR. GOUDIE:

A. I don't think we could, no.

CHAIRMAN:

Q. Okay. Just one last quick question on gas turbines. What kind of gas are you -- how does that work?

MR. HUMPHRIES:

A. The units we have now, they burn number two, which is basically diesel fuel.

CHAIRMAN:

Q. Oh, okay, alright. Well, that ends that line of questioning. Is there anything else before we break?

GREENE, Q.C.:

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Q. I believe Mr. O'Reilly would like to respond to some undertakings.

O'REILLY, Q.C.:

Q. Yeah. There were five undertakings, I think, correct?

GREENE, Q.C.:

Q. And for the record, we will mark these undertakings we haven't to date. The one you just filed on the carbon tax will be Undertaking No. 2, in case you wish to refer to it in your submissions.

O'REILLY, Q.C.:

Q. Okay. I'm just going to go through the ones -- the time period deficits to bridge the loss of 880 gigawatts from the system now, that's being worked on and we'll deal with that later.

GREENE, Q.C.:

Q. If that is the case, I would reserve the right, based on the information filed, to either have -- well, further RFIs obviously or possibly have a witness come back from Nalcor.

O'REILLY, Q.C.:

Q. Understand. Understand that, okay. The other, the second one that I have noted here

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is the requested confirmation of the change in the Vale numbers between DG2 and the current understanding, there was a question asked on that. And Mr. Stratton can speak to that, probably he can go over that. I think he's worked that number.

MR. STRATTON:

A. Paul Stratton. Vale, as of our DG2 analysis, indicated that the requirements were for 80 megawatts firm power and with an annual energy requirement of 640 gigawatt hours. As per our latest operating load forecast numbers that were just recently indicated to us from Vale, their requirement are now 84 megawatts of firm power with annual energy requirements of 670 gigawatt hours. So, just marginally higher with incremental firm power requirement of 4 megawatts.

O'REILLY, Q.C.:

Q. Okay, thank you. The next undertaking was a request to provide a total value of the tenders already awarded and ready to be awarded cumulatively, not by bidder, but cumulatively. And I think Jason you can speak to that. Mr. Kean will speak to that.

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(11:15 a.m.)

MR. KEAN:

A. Yes, Jason Kean. The total value is approximately 4.5 million.

O'REILLY, Q.C.:

Q. And the carbon charge on the domestic rate payers, we've dealt with that. And the last item, last undertaking was to provide the costing of adding additional reliability in Alpine regions of the transmission system. And Mr. Bennett, probably you could speak to that.

MR. BENNETT:

A. Thank you. So, we went back and looked at the Long Range Mountain crossing and I think we will want to file an update to Exhibit 97 because we do have the meterological loadings for the Alpine areas. So, we're happy to put that on the record. But the loadings in those areas are much higher than elsewhere on the line. And the cost per kilometre in those Alpine areas reflects those increased loadings. So, in the Long Range Mountains, for example, the cost per kilometre is approximately--more than double what we're

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spending per kilometre in the normal loading areas. So, that would put the cost per kilometre in the range of say eight hundred thousand dollars to one million dollars per kilometre. Those costs are reflected in a much more robust structural design in those areas, as well as the addition of additional anti-cascade structure to minimize the impact of a failure, should it happen.

So, if we were to look at, for example, upgrading the structural integrity in those areas, let's say 25 percent, the cost impact in those Alpine areas would be in the order of 20 to 25 million dollars. And maybe as a, just as an operational note on that, certainly our operational planning going forward will see, you know, additional repair structures for this new type of line on the system and certainly our emergency restoration plan would be focused on the Long Range Mountain areas.

GREENE, Q.C.:

Q. As a follow up question, the cost that you just gave us at that point, those are additional costs not included in the capital cost estimate of the transmission line

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included int he CPW analysis for DG2, is that -

MR. BENNETT:

A. That's right. Our DG2 estimate would--had an allocation in the cost per kilometre range that I identified. And to increase the structural capacity in those areas, the cost would be an additional 20 to 25 million dollars.

GREENE,Q.C.:

Q. Thank you.

O'REILLY, Q.C.:

Q. So, the only outstanding, we only have one outstanding undertaking and subject to that, unless there is some question arising out of those responses, I would ask that the Panel be dismissed.

MR. JOHNSON:

Q. After one of Commissioner Whalen's questions, I was asked to ask--and this is in connection with the question regarding any IOC requests for load, whether Nalcor has received any applications for power and energy from any other company or entity in Labrador.

MR. BENNETT:

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A. An application? If you can help me understand what you mean by that?

MR. JOHNSON:

Q. That's how it was put to me. I guess a request for power.

MR. BENNETT:

A. There's no firm request for power, no.

MR. JOHNSON:

Q. Thank you.

MR. BENNETT:

A. This might be unusual, M.r. O'Reilly, I think we have the answer for the 880 gigawatt hour. So, if it's convenient to the Chair, maybe we can address that before we -

O'REILLY, Q.C.:

Q. Okay, fine. That'll be--okay.

MR. HUMPHRIES:

A. Okay. Based on that, the actually deficit dates are similar to the assumptions that counsel made yesterday.

GREENE, Q.C.:

Q. I'm sorry, I was distracted wit the undertaking numbers. Are we -

O'REILLY, Q.C.:

Q. This is the first one, the one that we were

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deferring is going -

GREENE, Q.C.:

Q. Okay, you are -

MR. HUMPHRIES:

A. Yes, we do have those numbers.

GREENE, Q.C..:

Q. Alright.

O'REILLY, Q.C.:

Q. We're in a position to respond to that now. So, Mr. Humphries will with that.

MR. HUMPHRIES:

A. They are consistent with what we--counsel anticipated yesterday for the loss of an 880 gigawatt hour load in 2013. And we'd assume that we'd have a capacity of 125 megawatts. The capacity deficit would occur in 2023 and the energy deficit would now be in 2030.

GREENE, Q.C.:

Q. Sorry, I didn't hear your -

MR. HUMPHRIES:

A. 2030 for the energy, 2023 for capacity.

GREENE, Q.C.:

Q. Thank you. My team did do the calculations correctly then.

MR. HUMPHRIES:

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Q. Yes.

GREENE, Q.C.:

Q. They'll be kept on.

CHAIRMAN:

Q. So, that's it now, Mr. O'Reilly.

O'REILLY, Q.C.:

Q. That's it for the Panel.

CHAIRMAN:

Q. So, Mr. Bennett and your colleagues, thank you very much. If I may use a terrible energy pun, there was more light shed than heat, so thank you.

O'REILLY, Q.C.:

Q. That's good; that's the idea, thank you.

GREENE, Q.C.:

Q. During the -

CHAIRMAN:

Q. Yes, 15 minutes.

GREENE, Q.C.:

Q. We might need a slightly longer, we're going to change over the panel and MHI will start the presentation. Fifteen, twenty minutes possibly.

CHAIRMAN:

Q. We're in your hands.

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O'REILLY, Q.C.:
Q. So, another five on top of the fifteen, the usual. Okay.
(11:23 a.m.) (BREAK)
(12:06 p.m.)
CHAIRMAN:
Q. Now, Madame, you're on and I assume we'll go to around 1:00. Is that what -- or I'll wait for a certain look from a certain solicitor? Is that what I'm supposed to do?
GREENE, Q.C.:
Q. Thank you, Mr. Chair. That would be acceptable. I don't think the presentation will be finished at that time, so depending on the flow of the presentation, whether it's five to one or ten to one or five after one, but generally 1:00 will be acceptable.
CHAIRMAN:
Q. Okay.
GREENE, Q.C.:
Q. Mr. Chair, Manitoba Hydro International are here this morning and ready to present the report for the Commissioners and for the review process. I would like to introduce first the members of the panel who are seated

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over at the table. In the middle, we have Paul Wilson, who is the managing director of Manitoba Hydro International, and for this particular project, for this review, he was the project director. Seated immediately to Paul's right, we have Mack Kast, who for this review is the financial project manager. And on the other side of the table, we have Mr. Allan Synder, who is the project manager team lead and the biographies for each of the panel members, there is a short biography included with the Manitoba Hydro report in Volume 2. So with that introduction, I turn it over to Mr. Wilson who I believe will start the presentation.
MR. WILSON:
A. Thank you. Mr. Chairman, Commissioners of the Board, respective counsels and ladies and gentlemen, it's a pleasure to be here today to present Manitoba Hydro International's report. Assisting me today I have Al Snyder on my left and Mr. Mack Kast on my right and we will be splitting this presentation into the three parts and you have the pleasure of my voice for at least the first part of this

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presentation. I've been told to -- I guess I have a trait like many Newfoundlanders of speaking too fast and I've been told to slow down and I shall try to endeavour to do that.
O'REILLY, Q.C.:
Q. We listen fast.
MR. WILSON:
A. I have spent a fair bit of time here in Newfoundland in the last six months and it's been very interesting. A number of slides here today are included in material that's already been discussed.
GREENE, Q.C.:
Q. Excuse me, Mr. Wilson. I'm getting a sign from the back of the room that it may be difficult to hear you, so if you could speak up, please.
MR. WILSON:
A. How's that? Okay?
O'REILLY, Q.C.:
Q. Speed and a low voice is lethal.
MR. WILSON:
A. Yes. Thank you. A number of slides in this presentation we've seen already in the report through the cross-examinations and

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presentations and they're in here for completeness, but I may be glossing over, reading through them fairly quickly.
The outline of today's presentation, there's an introduction of the project and what we did and who MHI is, the options that were reviewed and our review methodology. What MHI did in this review has been documented. We talk the details of what Nalcor has done in terms of project screening and project estimating, which has a big impact on how the CPW analysis is constructed and presented. MHI was part of -- undertook a technical review of the materials provided by Nalcor and their various consultants, particularly in the areas of load forecasting, hydrology, reliability studies, the AC integration was reviewed, those studies, and there's some documents on NERC standards we reviewed. The infeed option and the Isolated island options were reviewed in detail and then we concluded with the CPW analysis and the results thereof and we'll have some concluding comments at the end of the presentation.

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It was a challenge to reduce all of this comprehensive material in the review into this presentation and for the most part, all the important points have been retained in here and some of the areas, I've de-emphasized since we've covered those extensively already in this hearing.

Central to MHI's review was the reference question. It was front and central and it defined what was to be done and how we undertook this undertaking. It was the foundation. It outlined what the options were and what we could not do.

MHI filed its report in January, which was made public January 31st, the report entitled "Two Generation Expansion Alternatives for the Island Interconnected Electrical System" and the two expansion alternatives were identified in the terms of reference and are as follows: the infeed option, which is the Muskrat Falls generating station and Labrador-Island link HVdc system, and the Isolated Island option which was largely a thermal generation expansion plan.

It's important to note what areas were

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not covered in MHI's review. The terms of reference did not include consideration of the following: alternative fuel types, for example, natural gas, coal or liquified natural gas. We did not consider other island supply options which were not part of the options presented to us, for example, biomass or tidal power, solar. Consideration of the export market via the Maritime link and the monetization thereof was not included in our review by terms of reference. Technical feasibility of the Maritime link was not reviewed nor were the electricity requirements in Labrador or the potential impact of the island rates for the ratepayers.

Now, MHI's engagement in this, Manitoba Hydro International, is a wholly owned subsidiary of Manitoba Hydro and Manitoba Hydro is a provincial Crown corporation charged with serving generation, transmission, distribution to the people of the Province of Manitoba, much like Nalcor is here in Newfoundland. MHI has provided consulting services in over 70 countries worldwide. The countries include a lot of post-conflict

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countries, Mozambique, Liberia, East Timor and then we move on to some other nice locations in Kenya, Saudi Arabia. We've been working in the United States, Canada and many other countries around the world. We provide consulting services and management services worldwide to these clients, including engineering.

Our engagement in this project was undertaken through a request for proposal. MHI was invited and awarded this contract through a competitive RFP process. This RFP is a public document and on the PUB Board website, along with our proposal. That contract was awarded on July 4th of 2011.

To undertake this work, MHI assembled a team of specialists, many of them in-house and from our parent company and from other contacts and contractors that we use in our projects around the world. We assembled this team to look at load forecasting, project management and they're experienced in utility resource planning, hydroelectric generation, engineering, operations and maintenance, thermal generation, HVdc engineering,

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operations and maintenance, hydrology, reliability, AC integration and planning studies, submarine cables and marine crossings, wind power and financial analysis and when needed, I would invite other subject matter experts from the parent company, when need arose.

Now I want to briefly cover the options reviewed. The first option was the infeed option, which is the Interconnected option with Labrador. We have a nice little diagram here, shows the route of the interconnection link, which the locations are approximate. The facilities are noted. The details of the infeed option are fairly well known. You know, there's a Muskrat Falls generating station, 824 megawatts with an average energy of 4.9 terawatt hours per year. The Labrador-Island HVdc transmission link or LIL is part of that. There's HVdc converter stations. There's the marine crossing at the Strait of Belle Isle and the addition of thermal energy plants and other energy sources to assist with capacity and demand.

The time line of these additional

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resources to the island power system has been outlined in many exhibits. In this one, we've drawn and extended out for the full study period, but the details, you know, are that there's the large investment in 2017 with Muskrat Falls and the LIL and then the next source isn't until 2036 with additional sources then scattered throughout the rest of the study period to 2067.

(12:15 p.m.)

With the Isolated island option, there is not interconnection to the mainland. As mentioned, it's largely a thermal plan focusing on the Holyrood thermal generating station with installation of pollution control equipment. It provides for life extension for the generation to 2033 and 2036. The plant is replaced ultimately with three 170 megawatt CCCTs. There's three hydroelectric generating stations in that plan with additions of CCCTs and CTs to fill out the energy requirements. Also, there's one new wind farm. Time line for this plan, you know, it's less capital intensive, but investments are scattered throughout the time horizon of the study.

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Now I'd like to describe our review methodology for how we undertook this work. This diagram is in our report. I guess what's important about it is that it somewhat mimics a generation resource planning process. There's a load forecast that's identified, that's fed in to the generation resource plan. It develops the alternatives. In our case, there was two alternatives to review. There's a large number of feasibility studies that were available or not available for both options and we had a number of volumes (phonetic) that were common to both options. Reliability analysis would be undertaken for both options and the CPW analysis or the financial business case for those options would be reviewed and then for our report, we developed our key findings from all of this material.

From the technical perspective, for the technical review, we looked at the generation resource plan, load forecast, hydrology, reliability, the feasibility studies for the various project components, AC system integration studies, the cost estimates and

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estimating methodologies and then the risk analysis associated with each of those projects.

For the financial perspective, financial review, we reviewed Nalcor's CPW methodology which has a number of elements in it, including capital and operating expenses. We reviewed the fuel price forecasts. MHI did an assessment on the allowance for funds used during construction as part of those estimates. We looked at the escalation rates, discount rates and the debt to equity component of those projects. We examined the power purchase agreements and we looked at the power purchase agreement, PPA, versus the cost of service methodology approach and their treatment for Muskrat Falls. In order to test the merits of the CPW results, we used a sensitivity analysis to determine what were the critical elements and the sensitivities to the CPW.

Now there's been a lot of material provided and talked about the project estimating and the Decision Gate process and how that works, so I won't go into a lot of

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details here. DG2 was the important milestone and all the study reviews that MHI undertook were at the DG2 level and we've also stated that not all the information was available for Nalcor to pass DG2, such as the AC integration studies in our key findings.

The DG3, which is project sanction, which Nalcor is endeavouring to move to now, is really the final check and confirmation of that investment or that decision is well founded to pass through that decision gate.

Now this is the last time you'll hopefully see AACE on any slide. It's very difficult. From now on, we'll call it just class four and class three, but we did follow the cost estimating methodology under this standard, which Nalcor has adopted for their project estimating. The important part here is the class four and class three estimates where class four is the study or feasibility level at plus 50, minus 30, and for class three was the plus 30, minus 20 or budget authorization, project sanction in Nalcor's case. It's a metric for our assessments when we're undertaking to review those cost

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estimates. If they fit within those ranges, then we would find that the work was reasonable. So we've seen that chart already, so I'll just go on. We're good.

Again, I'll just gloss over some of this, but the important part on this slide, other than the ranges and that, is the capital cost that we've seen in this hearing has a role in how the CPW analysis rolls out. So, you know, the refinements of these estimates are critical to that outcome of the CPW analysis. What ranges of accuracy are used have an impact on that CPW result.

Now, for risk review, Nalcor has documented in their documents and their consultants, they categorized risk under two headings, tactical risk and strategic risks and tactical risks, you know, is the evaluation of the design and planning aspects, for example, foundation risks of the Muskrat Falls dam, performance risks associated with contractors, weather or pricing, and then in terms of strategic risks, you know, there's changes in scope, market conditions and local factors that have an influence on how costs

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are estimated, and organizational risks, size and complexity of the project. So this was the platform for Nalcor's risk assessment.

In our review, we noted that as part of the technical review that risks were generally related into three areas: determination of costs, the timing of the projects and the ongoing technical and operational risk issues. Prior to DG3, Nalcor had done a fair bit of risk analysis work and factored it at a higher level in those reviews. MHI has documented these risks in our report where appropriate.

Now for generation resource planning, the time horizon is typically 20 years or more. You need to take the long view when you develop these very large projects. Generation planning is a function of the load forecast, generation retirements and government policy. The timing and the sizing of future generation is driven by the annual energy needs and peak demand requirements. Ideally you want to keep a reasonably tight relationship between supply and demand in order to maintain reliability and the economics of delivering power. Increments on both the demand and supply can

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be lumpy and what I mean by lumpy is they're rather large. In terms of Muskrat Falls, it's a large plant with the LIL at 900 megawatts and loads can be similar with, you know, I heard a potential 500 megawatt requirement in Labrador, Western Labrador, which may or may not come. Now, supply price may impact the load curve, thus the analysis is typically iterative. And we did not show any iterations on our--in our review since we're doing a straight-line review, but when you perform a CPW analysis, price has an impact on how much energy is consumed and that has an impact on, ultimately, the CPW. Depending upon the location, supply choices involve various preferred sources, so if you have indigenous sources on the island, that may be your preferred choice. The objective of generation which is declining is that--to determine the most economic mix to reliably satisfy the demand. And the supply equation must also consider security and reliability, environmental, social issues, transmission capabilities, et cetera. Also as part of the generation resource plan, reserve requirements

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must be factored in. There's been a lot of talk in this hearing and material presented about the loss of load hours. The amount that's established is based on reliability and economic factors. Interconnections generally reduce, reserve requirements while improving reliability. A sophisticated modelling program was used to optimize these preferred choices and in Nalcor's case, they used strategists, in Manitoba Hydro we use our own in-house tools, but the principles are the same. Newfoundland found that Nalcor's generation resource planning process is consistent with leading North American utilities, such as Xcel Energy, Minnesota Power, Ontario Power Generation, Trans Alta or ATCO--and I'll include Manitoba Hydro with that.

Now, I'd like to talk about Nalcor's load forecast. We're starting to get to the technical material and some of these concepts --we'll move on. The load forecast is key input into the generation expansion plan where the generation plan is structured to match load growth increments in both capacity and

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energy. As part of MHI's review, we completed a comprehensive review of Nalcor's load forecast methods, data sources, analysis techniques, using the Island of Newfoundland's historical load data and key inputs provided by Nalcor. MHI reviewed the rationale behind the historical load growth factors and we tested these factors and assumptions for future load growth. For example, the penetration of electric heat in the Domestic sector or the number of housing starts, these are inputs into the load forecast.

Past performance was measured by examining the accuracy of the last ten forecasts. In the econometric model, it's based on historical past performance to project forward. The load forecast is based on the summation of different sectors, you know, in Domestic, which is largely residential or is residential, general service sector, the industry or the Industrial sector and other, which is technically transmission lines.

So for the Domestic sector what did we find? Well it's based entirely on econometric

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modelling techniques and the results consistently under predicted future energy needs by a rate of one percent per year. The forecast error is nationally mitigated with the annual production of an updated load forecast and generation expansion plan which naturally biases it to correct for that. Now the most recent load forecast was done in 2010, and this is the load forecast we assessed. What we found for the Domestic sector was that the methodology was acceptable, but does not fully meet utility best practices for this sector and MHI recommends the incorporation of end use modelling techniques. End use modelling techniques will improve the capability to quantify load growth by end use, incorporate new energy uses into the model, quantify energy efficiency by end use or improve the design of conservation and demand management programs. It is important to note that, you know, even with the adoption of end-use modelling, the accuracy of the forecast may not improve, but the quality of the derived knowledge would.

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In the general service sector the methodology has produced excellent results, I'm using regression modelling and linear extrapolation techniques. The forecast was only one to two percent out as far as eight to nine years into the future. At this time implementation of end-use modelling techniques is not required. In the Industrial sector forecast accuracy has been adversely impacted by unforeseen plant closures in recent years. The load forecast for this sector has consistently over predicted load growth due to unanticipated mill closures. The future status of the existing pulp and paper mill is a critical component of the Industrial load forecast.

Industrial load, the total Island-Industrial load in the 2010 forecast was 1258 gigawatt hours and this represents approximately 17 percent of the total island load. The existing pulp and paper mill consumption in 2010 was 981 gigawatt hours, also representing about 13 percent of the island load, and now there's a new industrial, oncoming, I understand with Vale, which has a

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demand of 80 megawatts and 600 gigawatt hours in 2015 and I understand that there's additional--that has been revised recently and was discussed this morning.

Now this is the total Island energy demand over the study period, don't want to get into too many of the details, but after the 2029 period, since the load forecast is only done for a twenty year period, the load is extrapolated based on the average of the last five years to the end of the study period. So at the end you have a total load of 12 terawatt hours.

This next slides shows system peak demand, in terms of capacity and today you have about 1,600 megawatts of demand, capacity demand peak, and it goes to about 2,400 megawatts by the end of the study period in-- is it 2069? 2067, which is roughly about the same amount, the differential amount is about Muskrat Falls, about 800 megawatts. So our key findings in this area in load forecast, the load forecasting process was conducted with due diligence, skill and care and meets acceptable utility practices with the

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exception that end-use modelling techniques for domestic loads are not currently employed.

The load forecasting process has produced reasonable results for the domestic and line loss sectors, excellent results for the general service sector, and very poor results for the industrial sector. The industrial sector has adversely affected the overall energy and peak forecast results and in hindsight MHI finds that if the pulp and paper mill closures were accurately forecasted, the energy and peak forecast would have been excellent.

The domestic sector consistently under predicts future energy at a rate of one percent per future year. And as indicated, although the magnitude of the forecast error is acceptable, the frequency of the under prediction of the energy consumption should be addressed. And to solve this problem, I gather the model needs to be recalibrated in some fashion.

In the next ten years, the load forecast performance should produce good results, if the remaining pulp and paper mill remains

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operational. Conversely, the load forecast will significantly over predict electricity requirements, if the remaining pulp and paper mill closes.

In the long term, if the remaining pulp and paper mill stays operational, the load forecast is likely to under predict future requirements because the industrial forecast does not include any new loads for the study period. Another way to say that is it may be unrealistic to expect that there would be no new industrial load over a period of 50 years. And that is enough on load forecast.

The next area of topic I would to cover is reliability, and reliability, power system reliability has been discussed quite significantly in this hearing and MHI's report on this area. We've got the definition of reliability by NERC on the screen, which consist of two fundamental concept, which consists of two fundamental concepts: adequacy, all right, and what we call operating reliability, which is also termed security. Adequacy is the ability of the electric system to supply power and energy

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requirements at all times, taking into account scheduled and reasonably expected, unscheduled outages or system components. Operating reliability or security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components; for example, of the loss of HVdc transmission line. Now adequacy is the type of reliability analysis done in strategists for generation resource planning. Security is--can be assessed by deterministic means or by reliability probabilistic assessment methods as recommended in our key findings. Now there's generally two categories of power system reliability studies. One is a deterministic mode, which is subjective and based on engineering judgment, and then there's a probabilistic method, which is more accurate for reliability assessment. It takes into account the nature of the risks associated with the power system, and how we operate power systems. If events are random that occur, probabilistic assessment takes into account these random events. Also, these

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probabilistic methods are being recommended by industry-wide standards and by working groups. We have the MISO reliability working group there, but probably a better example would be the NERC generation and transmission reliability model task force, which fed the recommendations into the NERC resource issue subcommittee, which was approved, and which approved those recommendations for adoption by NERC. The deterministic methods noted above were the methods that were used in Nalcor's Exhibit 106 on reliability risk assessment as stated in the hearing by Nalcor. The probabilistic methods are applied system-wide and consistent risk factors for the component parts. Now the following are some examples where industry performs probabilistic reliability studies. The Northeast Power Coordinating Council, or MPCC, performs annual loss of load expectations studies for the region considering transmission restrictions, so they factor in the transmission system into their reliability assessments. Members of the Midwest independence transmission system operator utilities are a part of the Midwest

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Reliability Organization, or Reliability First Corporation, and they undertake these types of studies, and individual utilities also take these studies: BC Hydro, Idaho Power, the California ISO or--undertake these studies as part of the Western Electricity Coordinating Council. When we talk about reliability assessments for specific projects or mega projects such as Muskrat Falls and the Labrador-Island link, there's example of utilities that undertake these themselves. BC Hydro undertook one for the Vancouver Island Transmission Reinforcement Project, and Manitoba Hydro did these probabilistic reliability assessments for the HVdc Bipole III alternatives, and Hydro One does these studies as part of their transmission planning and asset management in Ontario. Now for a review of the probability system reliability-- or power system reliability, excuse me--MHI reviewed the related information provided by Nalcor, so we looked at the generation expansion plan documents filed in their exhibits. We examined Nalcor's Exhibit 106, Labrador-Island HVdc link and Island

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Interconnected Reliability study. We looked at CIGRE HVdc reliability surveys which collect member information on the performance of HVdc systems, and we also looked at the early Gull Island HVdc reliability analysis studies that were done in the 80's, and this was the information that was made available to MHI. Nalcor has established generation planning criteria related to the reliability of the island interconnected system and timing of generation additions, and this is a central driver in the strategist generation plan. Nalcor's capacity criteria of adequacy is a loss of load hours with a target of 2.8 hours per year, and I guess in layman's terms that means there's insufficient generation for two-point hours per year to service the needs of the customers, and MHI considers this criteria reasonable. Probabilistic reliability models performed in the 80's for the HVdc system have not been updated by Nalcor. MHI finds that Nalcor is Forced Outage Rate, or FOR, of .89 percent per pole for the Labrador-Island link is within the normal accepted range. The Labrador-Island link, FOR, however, should be

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replaced by a more advanced and comprehensive reliability model incorporating all components of the Labrador-Island linkage HVdc system, and Nalcor has stated that they are undertaking this work, which I applaud.

(12:45 p.m.)

When we talk about the normally accepted range of Forced Outage Rate, it's typically one percent, and then HVdc specifications, they typically have targets of about one percent for forced energy and availability, which equates to about a one percent Forced Outage Rate, and then two percent typically with penalty thresholds, so there's a contractual obligation on the manufacturers to provide a system that will perform reliably. This is from our experience. For your information, Mr. Chair, we don't know if those numbers are in the specifications since we have not examined those power system reliability findings. Deterministic assessments such as those performed by Nalcor cannot quantify the true risks associated with a power system, and are unable to provide some of the important inputs for making sound

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engineering and business decisions. Probabilistic reliability studies, including transmission considerations, have not been performed for the comparison of the reliability for the two options. MHI has determined that choosing between the two options under review without such an assessment is a gap in Nalcor's work to date. Typically these studies are completed as part of the DG2--Decision Gate process. Several Canadian utilities, NERC regions and members have adopted these probabilistic methods reliability studies, particularly for major projects. Risk factors are factors such as risk and associated cost, including potential larger societal cause related outages are not evaluated. Probabilistic assessment is an invaluable means to assess system risk, reliability and associated cost of benefits for various system improvement options, particularly for major projects proposed by Nalcor, and this is my last slide. MHI recommends that these probabilistic reliability assessment studies be completed as soon as possible for both options under

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review. Such studies should become part of Nalcor's planning processes that would allow them to do a comparison of the relative reliability for significant future facilities.

GREENE, Q.C.

Q. Thank you, Mr. Wilson. At this time, Mr. Snyder would start the presentation, so I don't know if this is a convenient time for you to break for lunch, Mr. Chair, or if you would like to carry on for a few moments. We would be switching panel members at this point.

CHAIRMAN:

Q. I don't care. What do people want to do? Do you want to keep going for awhile?

GREENE, Q.C.

Q. I'd suggest that we break at this point then if -

CHAIRMAN:

Q. All right, we'll break.

GREENE, Q.C.

Q. Yeah.

(12:47 p.m.) (BREAK FOR LUNCH)

(2:10 p.m.) (RESUME)

CHAIRMAN:

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Q. All right, madam, you can continue with your -

GREENE, Q.C.

Q. Thank you, Mr. Chair. Mr. Snyder will now start his part of the presentation with AC integration studies. Mr. Snyder?

MR. SNYDER:

Q. Thank you very much.

MR. SNYDER:

A. Thank you very much. Good afternoon, Mr. Chairman, members of the Board, members representing the legal facilities in Newfoundland, and women and gentlemen--gentlemen and ladies. I don't see--oh yeah, there's one lady in the corner.

CHAIRMAN:

Q. There's two.

MR. SNYDER:

A. Two, sorry.

CHAIRMAN:

Q. And she's upset too you missed her.

MR. SNYDER:

A. Why integration studies. Integration studies are necessary to assess the impact of new facilities on existing electrical power systems. Nalcor did provide us with studies

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for a 1600 megawatt, 3- terminal HVdc link between Labrador, Newfoundland and New Brunswick. They also provides us with a 1998 study of the Gull Island, the Soldier's Pond interconnection. However, the project definition has changed that DG2 with the Muskrat Falls development. Nalcor initially indicated that studies for the new project configuration would be available in November of 2011, and this was revised to March 2012, so we've really not had the opportunity to review the results of this study. Not having these studies completed has introduced an additional design and operational risk or potential unknown capital costs in the generation expansion plan. For example, there may be a need for additional transmission lines, additional AC equipment needed to regulate frequency or voltage or back-up generation to cover operational limitations of the Labrador-Island link. The detailed AC integration study is required prior to DG3 to fully conform--or to confirm the system requirements, operating parameters and risks associated with this elected option. The

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planning criteria is a document that clearly identifies the parameters that would trigger system additions to meet operational criteria as a result of demand. Nalcor's planning criteria was provided for MHI's review along with a self-assessment of their compliance to that criteria. In general, the transmission planning criteria in use at Nalcor follows best utility practices. It could be improved, however, by referencing external standards such as the transmission rating calculations. With respect to NERC standards, some of the key of NERC standards include reliability, communication, critical infrastructure protection, transmission operations, transmission planning, personnel performance, training and qualifications. While Nalcor has stated that they don't currently comply to NERC's standards, they have stated that they were launching a study compliance team, and that was good news to us, as a review team. NERC's standards are in place in eight of the 10 places in Canada, and the adoption of the NERC's standards is becoming synonymous with what's known as good utility practice.

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(2:15)
MR. SNYDER:
A. Application of NERC's standards is important. When the island interconnects to a neighbouring utility, and assurances of operational norms are part of the interconnection agreements. NERC's standards help to define these norms. The key findings that we found is that--from a transmission planning criteria, Nalcor generally follows utility best practices. With respect to the AC Integrational Studies, they should be completed prior to DG2 to adequately describe the facilities to operate the system under new configuration. However, they weren't done at this particular stage, and it's what we feel is a major gap in Nalcor's work to date. While Nalcor doesn't comply with NERC'S standards, we do recommend the decision that they've taken to undertake a self-assessment and prepare for compliance to the NERC standards with or without the Maritime link. I'd now like to review the hydrology studies that we went through that were made available to us by Nalcor. We reviewed the engineering

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documents provided by both Nalcor and their consultants as they related to the hydrology for Muskrat Falls and the three small hydroelectric plants on the island. MHI reviewed the time series river flows, the various heads associated with those river flows, and the results of the models provided. The software tools employed by Nalcor's consultants have been used on numerous hydroelectric projects on a global basis. We reviewed the project layout for Muskrat Falls and the characteristics including construction design flood estimates, the probably maximum flow and maximum floods, a spillway design, the numerical modelling of structures, the dam break analysis, ice studies, and the energy estimates. There were a large of reports, but these reports were structured with--a lot of them were structured with Gull Island built first. We reviewed the engineering analysis provided by Nalcor and its consultants and determined that it was appropriately done. In terms of the key findings, the Muskrat Falls studies provided by Nalcor were conducted and prepared by qualified consultants in

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accordance with utility best practices. The energy and capacity experts for Muskrat Falls were reviewed by MHI and confirmed to be reasonable for DG2. We looked, as I said, at the three small hydroelectric plants on the island, and found that Island Pond had an energy estimate of 186 gigawatt hours per year with a nominal capacity of 36 megawatts. Round Pond had an energy capacity--or an energy estimate at 139 gigawatt hours per year with a nominal capacity of 18 megawatts, and Portland Creek, the energy is estimated at 142 gigawatt hours per year with a nominal capacity of 23 megawatts. These have all been established by qualified consultants using similar techniques to Muskrat Falls using the head and average time series river flows. The key finding from the hydrology studies were that Muskrat Falls studies were conducted in accordance with utility best practices comprehensively and with no apparent demonstrated weaknesses. Also the energy an capacity estimates for Muskrat Falls and the three small hydroelectric facilities on the island, which were prepared by a variety of

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consultants using industry accepted practised were reviewed and confirmed to be reasonable for DG2, and now I would like to look at the infeed option, which includes Muskrat Falls, the HVdc converter stations, the HVdc transmission lines, and the Strait of Belle Isle crossing. Here's an overview from a mock sketch of Muskrat Falls and what it'll look like with the power house on the left and the spillway and the concrete dams on either side. Our technical review of Muskrat Falls included reviewing the proposed project layout and characteristics to identify any factors that might preclude successful development of this site. Confirmation that the scope of work of--for the project is both comprehensive and as a basis for planning. We assessed the methods used for preparation of the project cost estimate and evaluated the construction schedule. MHI also assessed the method used to prepare the cost estimates, and we'll get involved in that later with the CPW discussion. Nalcor used the work breakdown structure approach, or bottom-up estimate as we heard from them a couple of days ago. They

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provided extensive focus on construction and labour rates, construction materials, construction equipment, project management and engineering and they made provision for contingencies and cost escalations throughout the duration of the project. We did find that the capital cost of the project had increased by 104 percent between 1998 and 2010, but this can be largely explained by changes in scope of the project, inflation and an increase in the EPCM estimate, construction management estimate.

Key findings for Muskrat Falls were that the proposed layout and design of the generating station appears to be well defined and consistent with good utility practices. The general arrangement of the permanent works is a reasonable proposal for the optimum development in terms of both cost and construction duration and for those of you that are interested, the construction duration is estimated to be 62 months.

Another key finding is that based on the information provided, the proposed design and construction schedule is consistent with good

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engineering and construction practices and should not pose any unusual risk for construction or operation of the facilities. The available studies have identified technical risks and appropriate risk management strategies, and despite the increase in costs, MHI considers the cost estimate at DG2 to be within the accuracy range of a class four estimate, that is the plus 50 or minus 30, which is representative of a feasibility study.

In terms of the HVdc transmission link, the converter stations themselves, one at Muskrat Falls, a second at Soldier's Pond, as far as the Muskrat Falls station is concerned, each pole operates at a nominal rating of 450 megawatts, thus the transfer capability of 900. Each pole has an overload capacity of 150 percent or 675 megawatts on a continuous rating and an overload pole capacity of 200 percent or 900 megawatts for ten minutes. Without the overload capability, the loss of a 450 megawatt pole due to an outage, the load could not be supplied without backup and could lead to load shedding or possible blackout.

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The intended project is to transmit the 900 megawatts of power over 1100 kilometres of transmission line and inject this power into the island's electrical system at Soldier's Pond with an appropriate voltage and frequency control.

Here's a typical example of a footprint of a converter station. This happens to be the Henday converter station in the Province of Manitoba in the Manitoba Hydro system and you can see in the foreground consists of a dc switchyard, a converter building and in the background, a 230 kV switchyard. So you can see the footprint is not all that large, despite the fact that it's going to be the most significant station, I would guess, these two stations in the province.

Soldier's Pond converter station has a design similar to Muskrat Falls. It has three MVAr synchronous condensers to support DC conversion and stabilize AC performance. There's AC system upgrades required. For example, Holyrood units one and two will be converted to synchronous condenser units. Unit three has already been converted. A

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number of HV high voltage breakers will need to be upgraded as a result of the higher fault currents. Also associated with the HV converter stations is an electrode used for grounding and there's a distribution type line will be used to reach the electrode at each site location, one at the Strait of Belle Isle and one at Dowden's Point.

What we found is that most of the HVdc system documentation was not available, such as the converter station single line diagrams or the concept transition document, since the project definition was changed at DG2, and this really hampered MHI's review to form an opinion on the anticipated performance of the converter stations. MHI found that the HVdc converter station system design parameters that were available for review were reasonable for the intended application.

One of the key findings was the Labrador-Island design link was specified using line commutated converters for the HVdc technology and this technology is mature and robust for the application and I think that Nalcor spelled that out earlier this week. The

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estimated cost for the HVdc converter stations and electrodes that were reviewed by MHI were found to be within the range of a class four estimate. Cost estimates for the synchronous condensers, while low, are still within the range of a class four estimate.

We also found that there was no comprehensive HVdc system risk analysis of operation and maintenance done for the HVdc converter stations or the operational aspects of the Labrador-Island HVdc transmission line and outages could be lengthy and repairs expensive. For example, a converter station may take only -- may take a week if a spare isn't -- to repair if a spare isn't in the area; may take two and a half years if there is no spare. Risk analysis should be completed prior to completion of finalization of specifications of the HVdc converter stations post DG2. Functional specifications are being prepared by the EPCM contractor to be issued to HVdc suppliers as part of the detailed design.

Here's a picture of an HVdc transmission line and as you can see, the footprint is not

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significantly large and they're guyed towers and it's very similar to what would be built here in Newfoundland.

In terms of the HVdc transmission line itself, you can see some of the exhibits that we -- I'm not going to read through the exhibits that we went through, but there was a lot of available metrological data as input into the reliability base design.

The Nalcor decision to adopt the IEC standard and CSA code for design and reliability is appropriate. However, Nalcor does deviated from the code in our interpretation of it. Nalcor has used a 1 in 50 year return period and Nalcor also stated that the HVdc line need not be designed at a level greater than that of the existing 230 kV AC system. A significant icing event could occur however in an area remote from the 230 kV system which could down the HVdc line while all the 230 kV lines remain intact.

I've provided some examples of what other utilities are doing for critical lines that have an alternate supply. For example, the Manitoba Hydro Bipole III is being designed to

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a 1 in 150 year return period and in Alberta, AltaLink is designing to a 1 in 100 year return period with a 100 percent safety factor.

As this HVdc transmission line is a major component of the Island electrical system and given that the line has a singular failure mode, standards dictate a high reliability level. In terms of the HVdc transmission line outages themselves could also be lengthy and given that the HVdc line is the primary source of power in the Province, then rotating outages to interconnected customers could be a reality if the worst case scenario occurs. The length of the outage can be mitigated with a well prepared response plan. As an example, best utility response plans could include: an inventory of spare towers, conductors and insulators; trained operators and construction forces; mobilization and logistical plans; equipment on site; and supply agreements with neighbouring utilities, consultants, contractors and manufacturers.

The two-week repair period stated by Nalcor in their Exhibit 106 may not be

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realistic and is not an industry adopted metric. Remote regions in Newfoundland and Labrador may require additional infrastructure during periods when access is restricted. For example, in Manitoba, in order to achieve a system wide two-week repair period, additional berms, roads, and/or equipment located on site are required at many remote locations.

An option to meet load requirements could also be alternate supplies, and again, we heard from Nalcor on that matter. Connection to the mainland via Maritime link may be a viable alternate supply, provided this interconnection agreement allows for this and market conditions allow access to that power, also, standby thermal sources, CTs or CCCTs, and of course, retention of the Holyrood thermal station or curtailable load.

MHI recommends that a minimum of a 1 in 150 year return period should be used for the design of the transmission -- of the Labrador-Island link HVdc transmission line. The design choice selected by Nalcor is contrary to best utility practices and the IEC Industry Standard recommends 1 in -- suggests, I'm

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sorry, 1 in 500 year return period for a critical single sourced power supply. Nalcor should also consider enhanced reliability in the remote Alpine regions, considering the potential access problems, and again, we heard from this morning that they were intending to do that. But as a minimum, a 1 in 150 year return period should be employed where no alternate supply is available.

The capital cost for the HVdc transmission line fall within the range of a class four estimate, but appear to be at the low end of the range.

GREENE, Q.C.:

Q. Mr. Synder, perhaps if you could go back to slide 90? Your last bullet, you said something differently than what's shown on the slide there.

MR. SYNDER:

A. I'm sorry. As a minimum, 1 in 150 year return period is acceptable where an alternate supply is available.

GREENE, Q.C.:

Q. Okay.

MR. SYNDER:

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A. Sorry.

O'REILLY, Q.C.:

Q. And also, just make a correction that on the second bullet, instead of recommend, you used the word "suggested" in your oral presentation. Is that correct?

MR. SYNDER:

A. That is correct because we read the -

O'REILLY, Q.C.:

Q. You read the standard?

MR. SYNDER:

A. - read the standard.

O'REILLY, Q.C.:

Q. Okay.

MR. SYNDER:

A. It's still our recommendation.

O'REILLY, Q.C.:

Q. Yeah.

MR. SYNDER:

A. But it does say suggested in the standard.

Capital cost for the HVdc overland transmission line fall within the range of a class four estimate, but appear to be at the low end of the range and the incremental cost to extent from 1 in 50 to 1 in 150 year return

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period is approximately 150 million dollars, again which we've heard earlier, and within a class four estimate.

The Strait of Belle Isle crossing presents some specific challenges to this particular project and again, we had reviewed documentation from Nalcor. We evaluated things like the rock berms, the onshore trenching, cabling equipment and placement. Strait of Belle Isle crossing consists of three cables, 36 kilometres in length, two load carrying and one spare. The width of the Strait is only 18 kilometres, but cables will follow a circuitous route as a result of maximizing the depth of the cables. The intent is to keep the cables between 80 and 100 metres beneath the surface of the water.

Cables will enter the Strait using horizontal directional drilling techniques to a water depth of 80 metres and rock berms will be placed over the cables for protection against damage from anchors and fishing gear. The Strait of Belle Isle crossing is a critical component of the infeed option and construction of this particular component is a

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complex undertaking. Cable laying and protection could take up to two years to complete, two seasons.

Iceberg risk assessment. Local consulting firm C-CORE developed a model to assess the probability of cable contact by icebergs. Data indicated that iceberg scours were mostly present in deep water and C-CORE postulated that these iceberg scours had taken place in previous glacial periods. However, this could not be positively confirmed at this stage. Model studies found that the probability of iceberg contact with a submarine cable was one in 1,000 years at the depths planned for the marine crossing. The probability of contacting multiple cables was reduced with increased cable separation. And further investigation of iceberg scours and iceberg roll rates was recommended by C-CORE.

One of our key findings was that the selection of the plus or minus 350 kV mass impregnated cable is an appropriate technology selection for the application of an HVdc marine crossing operating at plus or minus 320 kV. Nalcor's base cost estimate for the

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marine crossing at DG2 was reviewed and found to be within the range of a class four cost estimate.

The iceberg risks, as perceived to be significant by C-CORE, has quantified the risk to be less than one iceberg strike in 1,000 years and this risk is further mitigated with rock berms and with increased cable separation. Additional research, monitoring of iceberg roll rates and bathymetric surveys of earlier iceberg scours should be done to provide a level of validation to further tune the iceberg strike model.

Application of a spare cable with as much separation as practical is a prudent design feature of the Strait of Belle Isle marine crossing considering the potential difficulties of bringing in repair equipment at certain times of the year.

Lastly, we reviewed the information made available for the Isolated Island option. The Holyrood thermal generating station consists of three heavy fuel oil boilers for a combined net generating capacity of 466 megawatts. The Holyrood station currently supplies

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approximately one-third, up to 2.99 -- up to 2,996 gigawatt hours annually, of the island's existing firm energy. The plant normally operates all three units during the highest customer demand periods of December through March.

Also noted for Holyrood was the fact that as of 2011, the units are 41, 40 and 31 years of age and operation beyond 50 years may not be viable. The plant may become unsafe and unreliable to operate before the 2033- 36 planned replacement period. With respect to Holyrood life extension, Nalcor has included 230 million dollars in the Isolated Island option to extend the life of the plant. The estimates don't appear to have been based on detailed engineering, but are considered reasonable for sustaining capital for the plant for DG2 purposes.

The Holyrood pollution control equipment additions with a projected cost of 603 million dollars with an in service date of 2015 includes electrostatic precipitators, scrubbers, low NOx burners, but as suggested earlier, the upgrade will not reduce

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greenhouse gas emissions which could be problematic if emission standards change. The pollution control equipment additions that were discussed earlier are not required to satisfy the current limit of 25,000 tons of SOx emissions even at full load. Continued use of the 0.7 percent sulphur fuel satisfies the current certificate of approval and the pollution control equipment additions are not required by current Federal regulations, but are based upon the government direction related to the Provincial Energy Plan.

The Holyrood replacement is anticipated to consist of three 170 megawatt number two oil-fired combined cycle combustion turbines installed in 2033 for units one and two and 2036 for unit three. The technology and costs for the replacement plant appear to be reasonable.

In terms of CTs and CCCTs, the Isolated Island option includes seven CCCTs and nine CTs and the methodology and base cost assumed for both the 50 megawatt CT and the 170 megawatt CCCT installations are reasonable.

In terms of the small hydro plants, as

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discussed earlier, the in-service dates: Island Pond would be 2015; Round Pond 2020; and Portland Creek, 2036. The project cost estimates and schedule are optimistic in light of more recent stringent environmental requirements these plants might have to undergo.

In terms of wind farms, there is only one new 25 megawatt wind farm proposed and that's for in-service in 2014. The two existing wind farms will be replaced after 20 years of service in 2028 and 2048. The capacity factor of 40 percent for these two plants is reasonable for a planning study and the estimated capital cost and operating expenses used in the CPW analysis are appropriate.

Nalcor's 2004 study which specified an upper limit of 80 megawatts for non-dispatchable capacity is considered reasonable as well. Additional wind beyond the 80 megawatts could result in potential spilling of water due to the limited hydraulic storage on the island.

Thanks very much for your attention. I would now like to turn the podium over to Mack

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Kast, our financial project leader.

MR. KAST:

A. Chair, members of the Board, counsel and parties present, I will address the matter of the cumulative present worth, otherwise known as the CPW analysis. To begin, we need to appreciate that when the government set out its mandate to the Board, it did not define the metric for making a determination of least cost. Rather, the CPW metric was defined by Nalcor in its July 6th, 2011 letter to the Board. The CPW focuses on costs only, those being capital expenditures, fuel costs, power purchases and operating expenses. The CPW approach excludes costs that are common to both options and the CPW does not take cash inflows into account. If it did, we would likely be looking at doing an NPV analysis or an internal rate of return analysis.

That said, MHI found the CPW approach to be reasonable for the purposes intended, that is to make a determination of the least cost between the two options. The CPW results, as per Nalcor's final submission, are set out in the table. We have heard numerous references

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to the base differential and it is a 2. 2 billion in favour of the infeed option.

MHI has identified a number of matters which I would like to highlight in my presentation, the first being the PPA approach versus a cost of service approach. This matter pertains only to the Muskrat Falls generating station. The PPA approach avoids the impact of rate shock following the implementation of the project for Muskrat Falls, in as much as the PPA rates are uniform over the period under review. In contract following a cost of service approach, the rates would be impacted by carrying charges on the undepreciated plant in the early years resulting in the highest rate impact in the early years following implementation of Muskrat Falls. However, quite apart from the rate impact, the choice of the approach has minimal impact on the CPW result. Dealing further with the derivation of the PPA rate for Muskrat Falls, the plant cost input for Muskrat Falls was based in 2010 dollars and it is assumed that 100 percent, that is 100 percent of the output from the plant would be

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sold. In the analysis, an 11 percent internal rate of return was targeted based on the project cash flows. The result was $75.82 per megawatt hour expressed in 2010 hours, estimated at 2 percent per year, first applied with a 2017 in-service date for Muskrat Falls.

(2:45 p.m.)

Now more specifically dealing with the PPA rate it relates to Muskrat Falls, using a $75.82 per megawatt hour rate, multiplied against the projected Newfoundland Hydro volumes, results in an internal rate of return of 8.4 percent. The internal rate of return of 8.4 percent is considered reasonable and positive relative to the 8 percent weighted average cost of capital approved by the Board in its recent rate decisions. Further, Nalcor was comfortable with the 8.4 percent internal rate of return since the derivation of the $75.82 per megawatt hour assumed 100 percent equity financing. To the extent that Nalcor can bring in debt financing to replace a portion of the equity financing, it will be able to lever up the 8.4 percent internal rate of return. Further, to the extent that the

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volumes in excess of Newfoundland Hydro's needs can be sold, such revenues will enhance the 8.4 percent return.

My final comment in this area relates to the take or pay aspect of the PPA rate. The PPA rate is proposed to be fixed at the time of the signing of the PPA contract between Nalcor and Newfoundland Hydro based on, as I understand it, the then-current Newfoundland Hydro planning load forecast. The PPA contract will be a take or pay contract for a 50-year term. The minimum revenues from Newfoundland Hydro to Nalcor for any given year, as I understand, will be fixed by contract at that time of signing. On the other hand, if the volumes exceed those in the contract, the unit rate will be, for example, the $75.82 per megawatt hour, of course, escalated.

My next area of comment relates to the discount rate sensitivity. Nalcor used a discount rate based on the weighted average cost of capital, that is the WACC. And the WACC was calculated being the composite 75 percent debt at 7.35 percent cost and 25

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percent equity at 10 percent cost, resulting in a weighted average cost of capital of 8 percent. Co-incidently, a WACC rate of 8 percent is in line with those rates approved by the Board in prior rate applications and MHI considers that the 8 percent WACC used in this instance is reasonable.

In terms of discount sensitivity, the discount rate would have to increase to 17 percent to result in a zero differential between the two options.

Looking next to the capital cost sensitivity, the Nalcor study is based on DG 2 estimating accuracy. If both Muskrat Falls and LIL capital costs are increased by 25 percent, the CPW differential in favour of the Infeed Option would be reduced from 2. 2 billion to 1.2 billion and that's with a 25 percent increase. However, as we understand DG2 level estimates for class 4 that would be cost estimates have the potential to increase by as much as 50 percent. An increase of 50 percent could cause the CPW differential between the two options to essentially become equivalent. And I say "essentially" because

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the net differential is reduced to 200 million from 2.2 billion. The capital costs sensitivity results for 25 percent and 50 percent increases to Muskrat Falls and LIL are summarized in the table as shown.

Moving on to load forecast sensitivity, Nalcor assumed a continuation of the operation of pulp and paper mill. Such a plant closure, however, would result in increased generation capacity of approximately 880 gigawatt hours per year, and if that were to be the case, the CPW differential would be reduced from 2. 2 billion to approximately 400 million, as shown in the table below. MHI also looked at sensitivity associated with fuel pricing for thermal plants. The fuel price forecast used by Nalcor were provided by the PIRA Energy Group. The PIRA forecast provides: reference, low, high and expected price forecasts. Using the March 2010 PIRA low forecast, the CPW differential in favour of the Infeed is essentially eliminated, and that is illustrated in a table below. In terms of this presentation, the PIRA high forecast was not illustrated, in as much as the CPW

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differential between the two options was already 2.2 billion in favour of the Infeed option and presenting a high forecast would only illustrate that the differential would be increased.

In short, fuel pricing forecasting will remain a challenge over the duration of the period under review. And this is evidenced partly by the fact, first of all, that one cannot buy derivative contracts probably for more than a year or two forward; secondly, PIRA itself only forecasts forward for 15 years and I consider that a pretty short window relative to the 50 year horizon that we're looking at in this review. And, of course the fuel price forecasting is a concern because as we've heard as much as 70 percent of the CPW value for the Isolated-Island Option is related to fuel pricing.

So up to this point I've only talked about sensitivity impacts from a single focused perspective. We can all appreciate that changing only one variable by holding all others constant is probably not that realistic, so let's take a look at the impact

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of a couple of examples related to combined sensitivities. The changes to the risk areas acting in unison could have a major impact on shifting the CPW differential. The first example: Assume the fuel cost decreased by 20 percent, the load growth decreases by 20 percent and capital costs for Muskrat Falls and LIL increase by 20 percent, in which case the CPW is essentially reduced to a minimal differential. Well, 100 million differential, but still in favour of the Infeed option.

In Example two, if we have a pulp and paper mill closure and capital costs of Muskrat Falls and LIL increase by 10 percent, the CPW is essentially reduced again to a minimal differential. This table provides a summary of the various sensitivity reviews. The scenarios are illustrated in order of diminishing differential. I spoke to the first nine items, I believe, up to this point and the tenth item that's in this table relates to how much would fuel prices have to decrease for the differential to be zero and the answer is 44 percent in this case.

So in summary, MHI has several key

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findings which I would like to highlight. First MHI endorses the CPW differential--I'm sorry, the CPW method as a valid approach for comparing the least cost of the two alternatives. In that regard, Nalcor has determined that the CPW differential is favourable to the Infeed Option by 2.2 billion dollars relative to the Isolated-Island Option. And the CPW results for each option have been validated by MHI based on the inputs used by Nalcor at DG2. That said, however, the CPW results may vary significantly if impacted by variations from the base case used by Nalcor for changes to, first of all, significant additions or deletions of load, for example the continued operation of the existing pulp and paper mill. Second, capital costs which at this point are based on DG2 level of review; and third, fuel prices which are difficult to forecast over the long term. Suffice it to say particularly as it related to forecasting for fuel prices, the risks associated with these inputs are further magnified given the length of the period under review, that is from the year 2010 to 2067, 57

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years used in the preparation of the CPW analysis.

MR. WILSON:

A. Thank you Mac. I would just like to make a couple of concluding statements as we wrap up our presentation, through MHI's work on this review, we've identified a number of areas of concern in our report which have been highlighted in the key findings.

GREENE, Q.C.:

Q. We need slide 133, Mr. McNiven.

MR. WILSON:

A. We have identified a number of areas of concern and we talked about a number of them already in our presentation, the areas in reliability assessment, which we found there's a gap in Nalcor's work; AC integration studies is another concern of ours as a gap; NERC Standards which Nalcor has decided and to prepare an assessment team to look at those issues; the transmission line design criteria was another critical issue highlighted in our review, and we noted that there are risks with the marine crossing at the Strait of Belle Isle, mostly with the concern of the relic ice

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scours--iceberg scours, pardon me, whether they're glacial or not, C-CORE has recommended further work to identify that and further turn their ice risk model. And the uncertainty associated with the continued operation of large industrial load on the Island.

Also noted in the hearing here and through our study, there may be a firm commitment for large industrial load in the future in Western Labrador that could change the generation resource expansion plan, and this would have impacts on how generation would be rolled out on the Island here. Fuel price forecasting will remain a challenge over the period under the review. Those risks, or the fuel price risks are not risks readily within our control. In conclusion, overall Nalcor's inputs, for example the capital cost estimates, fuel price forecasts and load forecasts into the CPW were developed in accordance with the utility best practices. And that the Infeed Option was found to be the least cost option of the two options reviewed, based on Nalcor's assumptions and the level of available information provided by Nalcor for

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DG2. And I would like to thank the Board and people here for your attention and this was a pleasure doing this presentation. Thank you.

GREENE, Q.C.:

Q. Thank you, Mr. Wilson, Mr. Kast and Mr. Snyder, that concludes, of course, MHI's presentation. It may be a suitable time to break to give the parties if they needed any time or--and then to reconvene after the break for questioning by, as I understand it, it is the Consumer Advocate who is going first.

CHAIRMAN:

Q. Okay, we shall break. Ten minutes, is that what we -

GREENE, Q.C.:

Q. Ten to fifteen minutes, sure, yes.

(3:00 p.m.)

(BREAK)

(3:26 p.m.) (RESUMED)

CHAIRMAN:

Q. I used to move faster. Now, where are we, Madam? We're with Mr. Johnson, are we?

GREENE, Q.C.:

Q. Mr. Johnson is going to be -

CHAIRMAN:

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Q. Oh, okay, sorry.
MR. JOHNSON:
Q. Thank you, Mr. Chairman. Good afternoon gentlemen. I am representing the consumers of the Province, as you know, in this proceeding and I guess before I start, I would like to just observe that I appreciated the clear language and the candour that you used in your report by times to describe things as you saw them and we'll visit some of that this afternoon so that I can get a better understanding of where you are, where Hydro is and see if I can wrap my mind around it. I have a question at the start on the point which, as you recall from my questioning of Nalcor, I spent some time talking about the classes of their estimates, and one particular passage that I pointed out to them in my questioning occurred at page 35 of your report, at volume one, where you referred to seeing a mix of class estimates. And the quote was that typically in the early stages of a project's development, a mix of cost estimate classes would be used as evidenced by what MHI has seen in the case of Muskrat Falls

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Generation Station or the Strait of Belle Island Marine Crossing, which were studied more extensively than other components. And I'm just interested in knowing what it is that you meant by that.
MR. SNYDER:
A. Basically some of the estimates that were done were 1988 and have been updated only with the price of inflation and some of the estimates have been done in 2010, so there was a range that had been conducted, and as a result, I would say that there was a range of class of estimates, some of them would be more accurate, those done in 2010 would probably be more accurate than those done in 1988 and escalated to today's dollars.
MR. JOHNSON:
Q. Okay, and when you say "more accurate" would you mean to suggest that they would fall in a different class under the AACE estimation methodology or what else would you mean?
MR. SNYDER:
A. Just degree of accuracy and so some of them suggested by Nalcor that they were talking about, they felt their estimate was a narrower

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range than the plus fifty, minus thirty. I would agree with some of their estimates probably are and some of the old estimates that were done, particularly as they related to the Isolated-Island Option, I would think would be at the upper range.
MR. JOHNSON:
Q. Which ones would be more at the upper range when we're thinking about the components of the projects in the Infeed Option?
MR. SNYDER:
A. The two hydro stations that were looked at as-- the two small hydro stations that were looked at.
MR. JOHNSON:
Q. Okay, and that's in the Isolated scenario you mean?
MR. SNYDER:
A. In the Isolated scenario that were not part of the overall integrated solution.
(3:30 p.m.)
MR. JOHNSON:
Q. And at the reference at page 35, makes a discussion of "as evidenced by what MHI has seen in the case of Muskrat Falls Generating

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Station or the Strait of Belle Isle Marine Crossing which were studied more extensively than other components" do I take that to mean that you felt that they were a bit more accurate than other components of the Muskrat Falls LIL?
MR. SNYDER:
A. Yes, there is no question that they have done some, you know, a lot of homework on the Strait of Belle Isle and we had an independent consultant do an evaluation of that estimate and while they're both, you know, not--I can't describe the numbers because they're--can't be produced on the record, but in fact I would say that both of those estimates have been done accurately and within a range of a class 4 estimate.
MR. JOHNSON:
Q. Okay, so they're still a class 4, but you would feel them as being in a tighter range?
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. And where would be the tighter range within that overall classification, in your view in

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respect of the generation station SOBI.
MR. SNYDER:
A. Yeah, they done a lot more engineering on both of those projects, so the range would probably be at the lower end in line with what Nalcor had suggested.
MR. JOHNSON:
Q. So the--you're referring I think in the evidence given by Mr. Harrington?
MR. SNYDER:
A. Right.
MR. JOHNSON:
Q. And that would be applicable to what components, the generating station and the SOBI, anything else?
MR. SNYDER:
A. No, I would say that we don't have sufficient information to make that judgment on the convertor station or the transmission line.
MR. JOHNSON:
Q. Okay. In relation to the transmission line, just to back up for a second, on an overall basis do you have--are you prepared to give us some guidance as to where you think the range is for the overall on the Infeed Option?

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MR. SNYDER:
A. I think it's fair to say that it's a class 4 estimate, that's what we looked at.
MR. JOHNSON:
Q. So you don't wish to make a comment as to where it would be within that estimate on an overall basis?
MR. SNYDER:
A. No, we were looking at the difference between the two options.
MR. JOHNSON:
Q. In relation to the cost of the transmission line, I understand it was priced at 400 million dollars, that component, but I understand there was a slight up date of that today on account of some of the more alpine regions and that one struck me because you did indicate that it was consistent with a DG 2 estimate but the low end of a range and I'd like, if you could just explore that a little bit with you in terms of what you meant by that.
MR. SNYDER:
A. Well even with the update that was given today for the potential for 20 million dollars to be

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added to the estimate for the Long Range Mountain Crossing, that would still be within the range of a class 4 estimate.
MR. JOHNSON:
Q. And I think your report indicates that you had some regard to benchmarking as a cost comparison to the number that Nalcor had provided with respect to the over land transmission line.
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. And what was the range of that benchmark that you were using as a comparison?
MR. SNYDER:
A. It would be in dollars per kilometer.
MR. JOHNSON:
Q. Okay, and what would the dollar per kilometer be in the range that you were referring to for the benchmark?
MR. SNYDER:
A. Well, you know, the 400 million dollars was the 1,100 kilometer transmission line and that's basically in the range of some of the other options that we looked at.

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MR. JOHNSON:
Q. And I take it--am I to understand you're aware of benchmarks out there in terms of a certain cost per kilometer of this type of line?
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. Okay, and what--who publishes these or which ones were you relying on?
MR. SNYDER:
A. There is internal confidential information that we have had access to, as to comparisons. Also, you know, you have to consider the terrain that you're going through and the types of crossings. This particular line, the LIL line is not, you know, not exactly the same as what somebody else would have built elsewhere.
MR. JOHNSON:
Q. With respect to--Mr. Kean I think described it as, you know, they took sort of a bottom-up approach and would they have described for you the bottom-up approach they took to that over land transmission line?
MR. SNYDER:

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A. In terms of the number of towers and things? No, they did not describe that to us.
MR. JOHNSON:
Q. Okay. So your comparison was more along the lines of taking their number and then comparing it to an external comparator being a benchmark.
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. And you indicate as well about the incremental cost and I think Nalcor provided the incremental cost to get up to the 150 year return period standard, being another 150 million, and in your report it would indicate that you can add that to the 400 million and still stay within the range, we're understanding each other so far?
MR. SNYDER:
A. That's correct.
MR. JOHNSON:
Q. Okay, and my question would be if you were told that there was an incremental cost of 150 million to get to that higher standard, do you then treat that incremental cost estimate

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itself as a class 4 estimate and then have to say, well, you know, that could be minus 30 to plus 50 itself, or do you just take the 150 and say that's a solid enough number and just add it to your, the 400 million. How does that work?
MR. SNYDER:
A. It does go within the range of a class 4 estimate with a 150 million dollars, it's, you know, we feel it's still applicable.
MR. JOHNSON:
Q. So you accept the 150 as a good tight estimate and that's how you do it, you don't -
MR. SNYDER:
A. It's reasonable.
MR. JOHNSON:
Q. Okay, all right, so the 150 itself is not subject to a possibility of being 50 percent higher, is it, the incremental cost of getting to the 150 line?
MR. SNYDER:
A. It was deemed to be reasonable, you know, and it was within the range of, again, of plus 50 or minus 30 on that.
MR. JOHNSON:

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Q. On the whole -
MR. SNYDER:
A. Yes, on the whole thing.
MR. JOHNSON:
Q. Okay. I guess as I said at the outset, the comments, you know, the very direct and candid comments on some of the issues is applicable now because I'm going to talk to you about the transmission line design. And, you know, your report has termed that a major issue, you've indicated fairly clearly in the report that you believe it to be contrary to best practices to pursue a one to fifty year return over the length of that 1,100 kilometer transmission line.
MR. SNYDER:
A. That's correct.
MR. JOHNSON:
Q. And I guess my purpose is not to challenge your view in that in any respect, my purpose is to ask you more about it and to get a sense of what you have to say about the Hydro position and see if I can get it straight in my mind.
MR. SNYDER:

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A. Okay.
MR. JOHNSON:
Q. And the discussion yesterday having to do with the Standard which is set out at page 62 of volume one, and this I would take it is a commonly referred to standard in the business?
MR. SNYDER:
A. Yes, it is.
MR. JOHNSON:
Q. And it's an international standard?
MR. SNYDER:
A. Yes, it is, adopted for Canada.
MR. JOHNSON:
Q. Adopted for Canada and I was interested about the bit of to'ing and fro'ing as to the interpretation of this standard. And Mr. Bennett, yesterday, pointed out a wording in the standard where he said, you know, it is suggested to use a reliability level characterized by return periods of 150 years for lines above 230 kV. And the same is suggested for lines below 230 kV which constitute the principal or perhaps the only source of supply, and then the standard goes on finally it is suggested to use a

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reliability level characterized by return period of 500 years for lines, and he said well, because it was suggested it's not mandatory and does anything turn on that in your view of the standard? Is that a point of significance?

MR. SNYDER:

A. I think it's a point of significance in the fact that the IEC standard suggests lines in excess of 230 kV should consider the use of 1 in 150 year return. It's the principal source of supply. It's routed through a mountainous area that has no transmission lines in it and very little history in the area. Could be integrated into a system, be it the Maritime link or elsewhere, and with all of those things considered, I would say that it's our recommendation that it stay at a 1 in 150 year return period.

MR. JOHNSON:

Q. And I accept that you are making that recommendation. If you go up to the top of the paragraph, it talks about in all cases lines should at least meet the requirements of a reliability level which would seem to be

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indicative of the 50 years as being a minimum in certain circumstances.

MR. SNYDER:

A. Yes, that would be our consideration, as a minimum.

MR. JOHNSON:

Q. And do you know or have any knowledge as to why it would be set out as a minimum for at least meeting the requirements of a return period of 50 years, but in the bottom two paragraphs be only a suggestion? Do you know any of the background on that?

MR. SNYDER:

A. I don't know the history of how this came about other than the fact that, you know, there are certain segments in the world that could not afford probably a 1 in 150, but in most of the areas in North America, I happen to be working in Alberta and in Manitoba where they've accepted a higher degree, a 1 in 150 or at least a 1 in 100 in Alberta.

MR. JOHNSON:

Q. And I'll want to address those with you as well. I wonder if you could look at the last paragraph of that standard which says "when

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establishing national and regional standards or specifications, decisions on the reliability level should be made taking into consideration also the experience with existing lines" and what is your understanding of what that means?

MR. SNYDER:

A. My understanding is that, you know, you should look at your past records in a specific area and given the fact that there is no record in parts of Labrador and the Long Range Mountains, I would suggest that I would take the conservative approach and be assured that I was building to the best standards that I thought was customer friendly, if you will.

MR. JOHNSON:

Q. And just to get your understanding of that, would data from other areas on the Island of Newfoundland, whether it be ice loading, meterological, would that, in your judgment, have any bearing or is that something that would be applicable to be taken into consideration under that aspect of the standard?

MR. SNYDER:

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A. Well, all of the information that you have for the route of the 1100 kilometres should be taken into consideration.

MR. JOHNSON:

Q. And I want to go to the examples of in Manitoba and Alberta in a minute, but I want to find out what you mean at the bottom of page 62 of the report where it says "no design optimization plan has been provided for the review or justification of the reduced transmission line reliability." And could you indicate what you mean by that sentence?

MR. SNYDER:

A. Well, I think some of that was due in the discussions this mornings when there was discussion of the fact that the original 3-terminal 1600 megawatt line specified was 1 in 150, and that some time in the past year or so that was reduced to one in 50 because of a different format, basically the Muskrat Falls line, and we were not privy to any of that information.

MR. JOHNSON:

Q. In terms of the best practices carried out by utilities in Canada and your report saying the

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design for less than 1 in 150 year return period is contrary to best practices carried out by utilities in Canada. Just elaborate on these best practices and how they arise.

MR. SNYDER:

A. When you have a line, as I suggested earlier, that's the principal source of supply, you know, to an isolated location like the island, it would be good, for safety and reliability standards, to use a 1 in 150 years return period.

MR. JOHNSON:

Q. And these best practices, to your knowledge, they would be applicable across the country except here--or not--

MR. SNYDER:

A. And they would be--they should be applicable anywhere.

MR. JOHNSON:

Q. --applicable everywhere--

MR. SNYDER:

A. Yeah.

MR. JOHNSON:

Q. --but they're not adhered to here, but they would be adhered to everywhere else.

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MR. SNYDER:

A. I'm not saying they're adhered to everywhere else, but I do know where they haven't been adhered to, and they're things that--the transmission lines in those particular instances are not the principal source of supply as they are here.

MR. JOHNSON:

Q. Okay, and I'm not taking issue with what you're saying. I am truly not. I'm interested in the debate on the topic.

MR. SNYDER:

A. Right.

MR. JOHNSON:

Q. The experience in Manitoba, just could you elaborate for us what that experience is in relation to that 150 year standard?

MR. SNYDER:

A. There is a new 1300 kilometre, 450 kV line being built from Northern Manitoba to Winnipeg, and it's being built to a 1 in 150-year return period, and that line is not single source because there's already two lines that are in that providing service from that same area.

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MR. JOHNSON:

Q. How long--that's a Line that's under construction?

MR. SNYDER:

A. It's not under construction at the moment, but it's under design phase.

MR. JOHNSON:

Q. Under design phase, and in terms of other--are there other similar lines that you can speak to in the province of Manitoba, for instance, that were also designed to that stage, or -

MR. SNYDER:

A. There's been nothing built in the province of Manitoba for the last 30 years other than that major one.

MR. JOHNSON:

Q. Okay. What would the existing transmission lines be? Would they be built to the 150 years?

MR. SNYDER:

A. I'd have to take that under advisement. I'm not sure what they were built too. They were built in 1971.

MR. JOHNSON:

Q. Okay, and you mentioned as well--in your

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presentation mentioned Alberta, and that's a slightly different standard, one in 100?

MR. SNYDER:

A. It's one in 100.

MR. JOHNSON:

Q. And just tell the board about that particular transmission line, the age of it and what it serves.

MR. SNYDER:

A. There are several transmission lines. Well, there's 14 billion dollars worth of transmission lines being built in Alberta over the next five years, including two transmission lines from the Edmonton area to the Calgary area, so balancing load DC lines. They're held at the present point in time. As a matter of fact, the Government of Alberta is to release a report on them within the next day or so as to whether or not they'll release them back into construction because they were started under construction, and the consumer's advocate them on hold until they can see whether or not they were used and needed to be used.

MR. JOHNSON:

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Q. In terms of the 1 in 500 year that we've heard some citizens and customers interested in discussing the fallout in the province of Quebec in 1998--

MR. SNYDER:

A. Right.

MR. JOHNSON:

Q. --and do you have any knowledge of what decisions were made there after that ice storm?

MR. SNYDER:

A. Yes, there was a 735 ring around the city of Montreal, and most of that ring collapsed, and so they rebuilt that--those transmission towers to a 1 in 700 and--1 in 500 year standard, I'm sorry.

MR. JOHNSON:

Q. What had they been designed to?

MR. SNYDER:

A. I really don't know that.

MR. JOHNSON:

Q. Thank you. You've dealt in your report with the counter argument, if you will, or the justification in terms of--well, if we--we could build the HVdc line to that more robust

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standard, but chances are, given our configuration here--or that's that argument--which are designed to a much lesser return periods, we could have a situation where the DC line stands and the rest of it is all down around our ears, and I'd like you to comment on that argument.

MR. SNYDER:

A. Well, nobody would wish that the transmission line come down at anytime, but if it does, you know, and then having not built it to the safety standard that we believe is necessary, would be unfortunate.

MR. JOHNSON:

Q. Do you have any opinion on the notion of--along certain elements of the line beefing it up more than other areas; for instance, in the Long Range Mountains and the Alpine--you know, what's your advice to us on that?

MR. SNYDER:

A. The advice was that, obviously, you know, as Mr. Bennett pointed out this morning. They've looked at the Long Range Mountains, things that they need to beef up and put in some dead-end towers. That's a good decision in

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our view, but then if it was all built to a 1 in 150 year standard, that may not be necessary. It may be necessary to put in dead-end towers as well as a 1 in 150 year standard in some areas.

MR. JOHNSON:

Q. No doubt, people in the province, sir, would be interested in your views as to reasonable or realistic response times to get a line back up and running in the case of a failure, and could you share with us your insights and experiences on that point?

MR. SNYDER:

A. You know, it's important that, obviously, you get the line up as quickly as possible. You know, it's cited that two weeks was a reasonable period of time, and I believe two weeks is a reasonable period of time if you've got a plan in place, a plan in place which has spare towers, which may have spare converter transformers, and some of those towers--and a plan that actually dictates where crews go, how they work. On personal experience, we lost a 2300 megawatt line in the province of Manitoba on September 5th, 1996, and that line

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was up within three and half days. However, it was also in an area that was easy to access, and equipment was available.

MR. JOHNSON:

Q. At what stage in the process of design and, you know, decision gates, etc., would it be reasonable for these types of plans to be formulated in terms of, "Look, this is the spare inventory that we're going to have here. This is the access points." Whereabouts in the process does that fit?

MR. SNYDER:

A. You should have it place before the line is commissioned, so do you need to have it right now, no, but you need to have it in place in terms of what you're ordering so that when the line is commissioned you have a plan in place to be able to restore that line because whether it's 1 in 50 or whether it's 1 in 150, that one period could happen the day after the line is commissioned.

MR. JOHNSON:

Q. That's right. I want to get your comment on the system reliability studies, and particularly interested to start off with the

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probabilistic approach and the probabilistic adequacy studies and, I guess, just to--can you try to explain to a customer what it is you're talking about?

MR. WILSON:

A. Probabilistic adequacy studies as Nalcor uses them in their strategist program as for generation resource adequacy planning?

MR. JOHNSON:

Q. I'm sorry, I can't hear you very well.

MR. WILSON:

A. Can you hear me now?

MR. JOHNSON:

Q. Yes.

MR. WILSON:

A. Okay. Can you repeat the question, please?

MR. JOHNSON:

Q. Yes, can you explain to the customer who's maybe tuning in what these probabilistic adequacy studies are that you're referring to in your major finding, #6, and loop the gap that you found in Nalcor's case. Make them understand that.

MR. WILSON:

A. That is a challenge.

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MR. JOHNSON:

Q. That is a challenge, yeah.

MR. WILSON:

A. Okay, maybe we can put the key finding, #6, up?

GREENE, Q.C.:

Q. It's Page 9.

MR. JOHNSON:

Q. It's at Page 9.

MR. WILSON:

A. Okay. Now the probabilistic adequacy studies that are being referred to in this key finding look at the entire Newfoundland Power system in its totality--well, including Labrador, right, with Muskrat Falls and those connections. Probabilistic studies, you know, take then into account the random nature of failures that would occur on a power system so, you know, if the line--a line goes out or a generator would trip off, or a combination of certain events, what is the impact on the power system for that event, but these studies take into account when you run them many, many, many thousands of different types of events that could occur on the power system,

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and you get, you know, an average reliability figure out of that. Now what does that mean to the customer as a number? Very little, right, but it is a tool that allows Nalcor to judge the relative marriage between one option or the other, so what is the reliability figure for the isolated island option versus the reliability for the infeed option, so you can see if reliability actually degrades with one option or the other, or improves conversely. Those are the types of studies that we've recommended in this key finding.

MR. JOHNSON:

Q. And where are--I take it, then that we are, in your opinion, lacking insight as to the ability to compare the two at the present time, is that the -

MR. WILSON:

A. Only in that these studies have not been done--

MR. JOHNSON:

Q. Yes.

MR. WILSON:

A. --by Nalcor or any consultant for the island power system, so there was nothing to examine

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or review.

MR. JOHNSON:

Q. Except the deterministic studies, I think.

MR. WILSON:

A. Of course, yes.

MR. JOHNSON:

Q. And in terms of the use of these deterministic studies, what is the problem with using those or relying on those and not having also the probabilistic approach applied?

(4:00 p.m.)

MR. WILSON:

A. Well, as we stated in our presentation, these deterministic evaluation methods are subjective, based on engineering judgment, which is good. Well, it could be good because it takes knowledge of the system into account, but in our view it does not identify, you know, the true level of risks between the two alternatives. It is--yeah, you've picked certain contingencies, representative contingencies to calculate what the impact on clients is, which may not be the highest risk factor, or I may be overstating a case particularly.

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MR. JOHNSON:
Q. Okay, the--I guess Mr. Humphries' of Nalcor indicated that--I'm sort of paraphrasing--it wasn't as simple as Nalcor making a decision to incorporate this level of probabilistic evaluation in our decision-making process because it could have significant implications, and we feel it needs to be addressed with the stakeholders, the regulator and customers, and I'm just wondering if that was a point that you had discussed with Nalcor, you know, prior to the hearing or--what's your reaction to that?
MR. WILSON:
A. I did not discuss that with Nalcor prior to the hearing or in this--in my meetings. The reliability expert that underdid the review may have discussed these concepts with Nalcor during his interviews and meetings with them, but I don't know, really, all the context of what was discussed and -
MR. JOHNSON:
Q. Do you have an observation about Mr. Humphies' observation, what he had to say about that issue? What do you make of that?

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MR. WILSON:
A. I believe the studies should be done as we recommended, yeah, because it provides information that is lacking in the decision-making process now. Now the decisions at the end of the day may be the same, right, but now you have that information on what is the cost and the relative merits of the risks between the two options, or any other development that may occur.
MR. JOHNSON:
Q. So Mr. Humphries' observation doesn't change your -
MR. WILSON:
A. No, it does not.
MR. JOHNSON:
Q. Okay, and I'm not inviting to change it. I'm just wanting to put it to you to see what you had to say about it. In terms of the AC Integration Studies, turn to Page 52 of Volume 1, and this would state at Paragraph 3.4.2 that the lack of an AC Integration Study looking at the new configuration of Muskrat Falls was identified or considered by MHI to be a significant gap in Nalcor's work to date,

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and the report says this information for a large hydroelectric project would normally be available prior to DG2, and these AC Integration Studies must be completed prior to DG3, and yesterday in essence, I think, Nalcor agreed--and I guess we could take up--put up the transcript from yesterday, Page 200, and in particular Line 8 where my learned friend, Ms. Greene, said--you indicated yesterday as well that you had done previous studies on system integration. Some were done in1998 when we had the proposed Gull Island development and Sales West, and in 2008 when you were looking at the 1600 megawatt, multi-terminal line with one terminal in New Brunswick, and that had provided you a level of comfort that you had sufficient for DG 2 purposes. Is that a correct paraphrasing of what you said, and Mr. Humphries said, yes, that was correct, and they also mentioned that they had personnel going back to 1998 involved with Teshmont and they still had two of those engineers, as I understood it, in shop and then Mr. Humphries said "now it was by no means a complete integration study, but it

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gave us that level of comfort to know that this looks very similar" and when I read that similarly, as I have done, I guess with this explanation, does MHI still consider the lack of a completed integration study a significant gap in the work to date or does that in some way go to the benefit of Nalcor?
MR. SNYDER:
A. We still consider it a significant gap. They have suggested they were doing it. Those two previous studies were looking at different size generation, different transmission sizes, different relocations. So, saying that they're similar is a bit of a stretch to me. Some of the same characteristics, yes.
MR. JOHNSON:
Q. Yeah, okay. The MHI report at page 53 says, toward the first full paragraph on the top of page 53 says "with the redefined project definition, these studies do not adequately describe the facilities required to successfully operate the transmission system under the new configuration. As such, there may be unidentified risks in proceeding with the project at this time. For example,

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studies could identify the requirement for additional backup generation, new transmission, enhanced protection schemes or other system additions." Now as I understand it, Mr. Humphries indicated in his comments to the Board that what they considered at DG2 as a result of the analysis they did was -- that was needed based upon their view of the integration needs was three additional synchronous condensers at Soldier's Pond -- at the Soldier's Pond converter station and a number of circuit breakers that were identified. Is that your understanding?

MR. SNYDER:

A. That's one of the things that they've done, yes.

MR. JOHNSON:

Q. Okay. And in terms of these unidentified risks, I guess consumers tend not to like risks and then they tend really not to like unidentified risks and I guess I'd like to have, you know, some measure of the risk that may be there in the absence of these integration studies, albeit they're being done for DG3 as we know.

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MR. SNYDER:

A. You know, I can't give you a definitive number in terms of value of what those may be, but there's certainly things that they may have to -- you know, when you model the system, that they may choose to incorporate because it makes better practice, better operation of the system. It makes the system more reliable and as a result, that might change the number of dollars that are required.

MR. JOHNSON:

Q. Could it -- and I guess is it also possible that what they've already incorporated is sufficient as well. I guess that remains a possibility.

MR. SNYDER:

A. Yeah, that remains a possibility.

MR. JOHNSON:

Q. In relation to then the costs for the three synchronous condensers and the several high voltage breakers, I understand that MHI considered the cost estimates on these to be on the low side and using data from similar prior projects and I think they came in in the DG2 estimate at 198 million, and I'd just like you to give us an indication of how low?

MR. SNYDER:

A. Well, within the class four range.

MR. JOHNSON:

Q. Okay. So that means the -

MR. SNYDER:

A. It's confidential information that I don't think Nalcor wants us to use.

MR. JOHNSON:

Q. Okay. But it would still fit within the range, but you felt it was low?

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. Based on similar prior projects?

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. And recent similar prior projects?

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. In your province or -

MR. SNYDER:

A. In Alberta.

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MR. JOHNSON:

Q. In Alberta, okay, and this is the cost of the hardware?

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. I'm probably going to revisit some of the areas of NERC but probably won't be doing it this afternoon, but I do want to switch gears a little bit and talk about the thermal generation and particularly Holyrood. The first point I want to bring up with you is the pollution control equipment that you say "with pollution control equipment installed at Holyrood, greenhouse gases will continue to present a challenge to its long term operation should emission standards change" and you talk about a risk that a facility such as Holyrood may not be able to operate long term.

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. And I take it you're speaking there because of environmental considerations and regulations?

MR. SNYDER:

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A. That's correct.
MR. JOHNSON:
Q. And I think your report speaks in terms of it being likely that there could be changes which could affect Holyrood's future?
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. And likely means probable, 50 plus 1 I suppose, but what do you base it on?
MR. SNYDER:
A. Based upon what's happening in Ottawa and what's happening with respect to the move towards the elimination of greenhouse gases in Canada.
MR. JOHNSON:
Q. Could you elaborate?
MR. SNYDER:
A. The one item that they have put in place is that all new generation will have to be with standards that meet natural gas emission standards and all existing plant, when it reaches 45 years of age, will have to meet greenhouse gas emission standards.
MR. JOHNSON:

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Q. And what's your basis -- you're thinking that that might be -- have applicability for Holyrood obviously?
MR. SNYDER:
A. Yes, I do.
MR. JOHNSON:
Q. Are there, in other jurisdictions in the country, are they taking steps in advance of that happening to deal with that possibility or likelihood?
MR. SNYDER:
A. Yes, in Ontario they have taken steps. They're shutting down thermal plants in Ontario. Now they're coal thermal plants. In Nova Scotia, they've done an evaluation of their coal and oil burning plants.
MR. JOHNSON:
Q. And what have they determined as a result of that?
MR. SNYDER:
A. I don't know what their final decision is, but they have done an evaluation for sure.
MR. JOHNSON:
Q. And is there any way to, you know, quantify that type of risk in CPW terms or is it just

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intangible?
(4:15 p.m.)
MR. SNYDER:
A. I would say it's intangible.
MR. JOHNSON:
Q. Speaking of the pollution control equipment, I think your report, you know, raised a question about the efficacy of spending a large sum of money to install scrubbers and precipitators and what's your concern about that?
MR. SNYDER:
A. Once you've spent the 603 million dollars, you still have greenhouse gases.
MR. JOHNSON:
Q. And as you're probably aware, there's an energy plan that was delivered in 2007 where the Province made a commitment.
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. And I guess, do you have any familiarity or experience with such policies of provinces and how that gets brought to bear on the point?
MR. SNYDER:
A. Essentially, the utility is mandated to follow

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the plan.
MR. JOHNSON:
Q. And I take it you would interpret the 2007 energy policy as a mandate?
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. The other risk that was raised was with respect to the Holyrood service life and again, I think this was an area where your report was fairly clear and direct in relation to some disagreement with AMEC about how long its conceivable to operate that facility, even putting aside the environmental considerations, and you've indicated that it's widely accepted in the industry that useable plant life is typically a maximum of 60 years including life extension work.
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. And in terms of widely accepted in the industry, are you speaking in terms of Canada or the United States?
MR. SNYDER:

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A. Canada.
MR. JOHNSON:
Q. In Canada?
MR. SNYDER:
A. Yes.
MR. JOHNSON:
Q. And does that mean that you can't operate a plant beyond that or you shouldn't?
MR. SNYDER:
A. It does not mean you cannot operate it. It does mean that you should do a thorough analysis of that plant and ensure that safety and reliability are there for its operation.
MR. JOHNSON:
Q. You indicate that you -- or the report indicates that the determination of remaining life of the equipment appears to be fundamentally based on operating hours and not on total life. Just explain to us what the distinction would be.
MR. SNYDER:
A. Those plants didn't operate or do not operate, as you're aware, on a full year basis. Therefore, the assessment that was done by AMEC was on the number of operating hours, as

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opposed to the total number of hours in a year.
MR. JOHNSON:
Q. And you believe, it's your opinion or MHI's opinion that you should look at the total life?
MR. SNYDER:
A. We believe it should be the total life.
MR. JOHNSON:
Q. Okay. Your report points out that there may -- this is page 13 of Volume 1. "Even with life extension under the Isolated Island option" -- this is paragraph 23. Even with life extension, "operating Holyrood beyond 50 years to a maximum of 60 years with reduced reliability may not be practical. There may come a point well before 2041 when the plant becomes unreliable to operate and the life extension plan and requirements under the infeed option are as follows:" and why did you make a point of pointing out 2041 in that statement?
MR. SNYDER:
A. The only reason for pointing out 2041 was if it was ever intended that that plant operate

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until such time as the power became available from Churchill Falls.
MR. JOHNSON:
Q. You're saying forget about it?
MR. SNYDER:
A. I'm saying that, you know, by that particular stage, you're over 70 years.
MR. JOHNSON:
Q. Okay. So that's not really an option?
MR. SNYDER:
A. You also need the sync condensers, you know, for reliability.
MR. JOHNSON:
Q. At page 166, and this would be in Volume 2, you -- and this is under paragraph 10.4.2, life extension, in the second paragraph of that section, in meetings with Nalcor, it was indicated that a cost estimate of 100 million dollars was identified in the CPW analysis for the life extension work, 20 million dollars a year from 2012 to 2016, and was based on comparisons with similar plants in the region, example: the Trenton Generating Station, a Nova Scotia plant, I guess built in 1969; the Coleson Cove generating station in New

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Brunswick, from 1976 vintage, and you indicate MHI agrees that the 100 million estimate is conservative and appropriate for DG2 and what's the basis for saying that you believe it is conservative, these other life extensions in the other plants that you referred to?
MR. SNYDER:
A. Yes, the two other plants that were evaluated and the fact that this particular plant would -- under the Isolated Island option, would keep it in operations, units one and two until 2033 and unit two until 2036.
MR. JOHNSON:
Q. And I guess is there a difference between conservative and low?
MR. SNYDER:
A. That's your interpretation.
MR. JOHNSON:
Q. I guess what did you mean?
MR. SNYDER:
A. It seems like it's sufficient amount of money to keep the plant operational until those dates.
MR. JOHNSON:

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Q. Okay. Page 171 of your report refers to, at the top full paragraph, "CO2 emission issues and/or costs have not been addressed in this report. Greenhouse gas emission standards are likely to be set by the Federal government and as such pose a risk to the ongoing operation of Holyrood thermal generating station as a generator" and I note at page 170 is the reference at the bottom of that page to the generation planning issue, July 2010 update, where it references the 866 thousand tons a year of CO2 where it states "the most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide is the primary greenhouse gas of concern and Hydro's Holyrood plant emits an average of approximately 866 thousand tons per year of CO2 based on the five-year average from '05 to '09" and that's where that figure came from.

What should we do -- and we know that these costs are only treated as a sensitivity for the purpose of the CPW analysis and I wonder, do we give it any more weight than that? Do we -- how significant is it in the

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scheme of things? Let's say if the two options ended up where we thought that they were close. What becomes of that consideration?

MR. SNYDER:

A. I would give more consideration to being able to get an exemption from Ottawa to keep operating the plant.

MR. JOHNSON:

Q. And so you would expect that there's some sort of exemption being -

MR. SNYDER:

A. No, I didn't say that. I said I would apply for one.

MR. JOHNSON:

Q. You'd apply for one, okay, and hope you get one.

MR. SNYDER:

A. Hope you get one.

MR. JOHNSON:

Q. So it remains a risk, but what do we do with the risk? We bear it in mind when we're looking at the two options?

MR. SNYDER:

A. You bear it in mind if you were choosing the

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infeed option. If you're choosing the -- or the Isolated island option, I'm sorry.

MR. JOHNSON:

Q. Yes.

MR. SNYDER:

A. If you do the infeed option, it's not a problem.

MR. JOHNSON:

Q. Your report as well, talking about fuels, we have, as your report notes, a forecast and we've got a long study period and we've got an isolated option that is very oil centred.

MR. SNYDER:

A. Yeah.

MR. JOHNSON:

Q. And as we know, the PIRA Energy Group price forecast don't extend -- do not extend beyond 2025 at the time of the DG2 analysis and for analysis purposes, Nalcor has projected those prices beyond 2025 by holding PIRA's 2025 price levels constant in real terms and would that be considered a reasonable methodology in the circumstances where we can't look out as far as we might want to?

MR. SNYDER:

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A. Yes, I think it is.

MR. JOHNSON:

Q. And the idea of holding them sort of constant, with the exception of -- or an inflation type of assumption, would that strike you as being conservative or just reasonable? I'm trying to get a sense of -

MR. SNYDER:

A. I think it would be reasonable.

MR. JOHNSON:

Q. You make reference as well to the fact that when you have that long time horizon, in terms of the study period, that it magnifies the uncertainty.

MR. SNYDER:

A. Correct.

MR. JOHNSON:

Q. And in one part of your report, you make the statement and I think it fairly applies to fuel costs, fuel cost assumptions. What other factor does that magnification factor -- where does it concern us?

MR. SNYDER:

A. Well, fuel cost is a major for sure because it's 70 percent of the overall cost of the

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Isolated Island option. Once you have the plant in place, for sake of argument, for the infeed option, there isn't a lot of risks associated with that because the operating costs are low.

MR. JOHNSON:

Q. So in terms of this sort of study period, I think your report would indicate that -- at page 188, I believe -- that the study period was considered reasonable, recognizing the life of the assets.

MR. SNYDER:

A. That's correct.

MR. JOHNSON:

Q. And so I guess if you're looking at comparing two options with an asset life that goes out that far, that's a legitimate exercise. You wouldn't say "well, we can't look at that because it goes out too far"?

MR. SNYDER:

A. No, you would consider that full length.

MR. JOHNSON:

Q. The full length?

MR. SNYDER:

A. Yes.

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MR. JOHNSON:

Q. Does the length of the study period produce a mathematical bias in favour of one option or the other at all?

MR. KAST:

A. It's Mack Kast here. I don't believe it does. In fact, it's very important that the study period be extended to the full life of the significant assets and those being Muskrat Falls and LIL.

MR. JOHNSON:

Q. And how about the notion that under the Isolated option, you are, you know, adding plant and equipment towards the tail end of the study period, for instance. I guess you're doing the same thing in the Muskrat option, but to a lesser extent. But that we haven't got to worry about there being a bias in that?

MR. KAST:

A. No, no, I don't believe there is. We did look at that and we did observe that with respect to the Isolated island option, that there were some undepreciated assets because of the CT plants and so on that have not been brought

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in, but we did not consider that to be material in as much as when you discount those values back to the present. It was really -

MR. JOHNSON:

Q. So far out.

MR. KAST:

A. Became insignificant.

MR. JOHNSON:

Q. Okay. As you know, in terms of looking at the overall infeed project which, you know, the generating station plus the LIL, there's more money in the Muskrat Falls generating station side of things being spent than there is on the LIL and I guess the -- so, in terms of, you know, we have, I think, two billion dollars approximately being spent in connection with the LIL and about 2.9 billion in connection with the Muskrat Falls generating station, so on a weighted basis, we are relatively more sensitive to overruns on Muskrat Falls than the Labrador-Island link, just as a mathematical point of view, and I wonder, do we -- can we get any comfort out of the fact that there seems to have been so much work done on the generating side of the

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project in terms of the studies and the level of effort that went into the generating side in terms of giving us some more confidence in where they are as at DG2 with the Muskrat Falls generating side of things?

(4:30 p.m.)

MR. KAST:

A. I will let my colleagues speak to this as well, but I would like to say that with respect to that point that you did mention a minute ago about the time horizon and really with respect to the infeed option that matter is reigned in for the most part, in as much as the costs for the infeed option will be expended by the year 2017. So the time horizon first of all is significantly shorter and secondly, we're moving from DG2 to DG3, in which case the costs are going to be determined and cemented in to a large degree in contrast to the Isolated Island option which now is extending further out and is very fuel sensitive and that's where the concern in terms of long time horizon comes into play. I don't know if there is additional comment.

MR. JOHNSON:

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Q. No, I think what I was -- and I don't know if we've missed each other, I misunderstood you or what, but I guess what I was getting at is that we have -- as I understand it, you know, there was some commentary in the MHI report around the level of detail that existed around the Muskrat Falls generating station side of things and given that there was about three billion dollars being spent on that, whether -- and two billion dollars being spent on the Labrador-Island link, it seemed to me that maybe there was -- we would feel -- we would be a bit more protected on the Muskrat Falls generating side of things, having regard to the amount of project definition they had at DG2.

MR. SNYDER:

A. I would have more confidence in the Muskrat Falls generating station.

MR. JOHNSON:

Q. Component.

MR. SNYDER:

A. Component, at the present point in time because there's not much--we hadn't seen much on the HVdc switchyards, converter

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switchyards, nor have we seen much on the transmission line, actual design itself, itself which is under way at the present point in time.

MR. JOHNSON:

Q. Okay. I found your comments in your report on the fuel cost projection, just to circle back to that for a second, to be interesting. And if we could bring up page 204 of your report. And I guess the sentence that I focused on was just under Table 40 and you make the comment, "what is more critical of the accuracy of the base price projections. This raises the issue of how to best incorporate such uncertainty." And then you have a description of PIRA's reference price and low price, high and expected price. And on the next page you talk about the expected price scenario being calculated as the weighted average price forecast of the reference low and high cases. And that the expected price forecast encompasses the uncertainties in the other three scenarios into one. And because you also noted that PIRA also estimates the discrete probability of occurrence for each of

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the reference, the low and high. And when I read it, I was left with the question, you must be saying this for a reason. And I was thinking, is the point of this exercise is that you're maybe recommending that we should probably incorporate expected as opposed to reference or what was your thinking on that?

MR. KAST:

A. Mack Kast here. We did hear at the outset from Nalcor that they did speak to the matter of using the expected price and indicated that there's a probabilistic element to that. And it was the right thing to apply if one was trying to get at the matter of the risk in terms of where the prices might be moving to. And so it does have an application in that sense and it is a rate thing. Using the reference price which is what PIRA is saying is a likely outcome, for example, in this case resulted in a 2.2 billion dollar advantage for the infeed option. What we found was if we moved to the expected price and inserted it instead, that the differential indeed increased. So, what it does is it tells us that there's an even higher differential,

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first of all, but that the probability of it moving there in terms of using expected prices, a reasonable thing to think about.

MR. JOHNSON:

Q. Okay. I'd like to talk about the industrial load forecasting, in particular. And I guess as you know, we don't have, in this province, very many, in fact we have very few industrial customers. And you know, I guess the question that I would have is what can Nalcor do, what should they do in terms of trying to forecast that load? Is there a recommendation in that regard? Is there room for improvement on how they go about their industrial forecast? Like, you made suggestions on the domestic side of things, can you indicate what your thoughts are on that?

MR. SNYDER:

A. Yeah, the principle that we have followed in the past in Manitoba is to do what Nalcor says they're doing. That's interview each of the major customers, once or twice a year and get a value for what they expect in the future. And certainly it's key at Corner Brook because it plays such a large role in your particular

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environment. I would also encourage people to seek out other industries, whether it be in mining or forestry, whether it be in Labrador or in Newfoundland, as to, you know, what is the potential? Is there any potential for you setting up a plant or setting up a manufacturing facility that might require a certain amount of energy? That's difficult to do, I understand that, but I would like to have a better handle. I feel that 50 years into the future - no more major industrial, I can't believe that.

MR. JOHNSON:

Q. So, that would be--you didn't use the word conservative, you used the word pessimistic in the report.

MR. SNYDER:

A. What I'm saying is that we should be--you should search out what you think is reasonable and if there's anything else that you can add to it.

MR. JOHNSON:

Q. In Manitoba and as you indicated, you follow a similar approach in terms of contact.

MR. SNYDER:

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A. Yes.

MR. JOHNSON:

Q. And how many industrial customers would you be talking about in Manitoba?

MR. SNYDER:

A. It's probably 20 or 25.

MR. JOHNSON:

Q. Okay. And if you, you know, make the communication and have the contact as has been described and they tell you, here's our forecast, do you do anything besides say, well look, these people are going to--they're saying they're going to be in business and we've got a load to serve. I'm trying to get a sense of do you assume, oh no, they might get in trouble and I've heard this or that in the papers and--trying to get a handle on this.

MR. SNYDER:

A. The load forecast people try to take that into consideration because they say they're going to have a 100 percent load for the foreseeable future and it's a gold mine and you've been reading that there's a three year supply in that gold mine. Then you better take that

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into consideration in your load forecast, reduce the probability of the mine operating past a certain point.

MR. JOHNSON:

Q. And that's probably an easier example, you know, because every mine has a life, we know, right from the start, based upon assumed production levels.

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. We can time it to the month that it will end. It seems, just inviting your comment, it seems to me that it's not as easy in an industry that tends to be cyclical.

MR. SNYDER:

A. No, that's true and I would hope that the people that you were dealing with the pulp mill or the pulp and paper mill were reasonable and that they were rational in their approach as to what their load would be.

MR. JOHNSON:

Q. And if you feel you're dealing with a rational customer, I guess and they say they're going to be around, you assume they're going to be

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around?

MR. SNYDER:

A. They're going to be around.

MR. JOHNSON:

Q. Now, we know that there is risk around that.

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. And for that very reason you brought it rightly to the Board's attention and to the customer's attention in your report and on that--that was sensitivity analyzed. If I could ask you to turn up--and I might be speaking to your colleague now.

MR. SNYDER:

A. Yes.

MR. JOHNSON:

Q. Page 87, Table 14.

MR. MCNIVEN:

Q. That's Volume 1, is it?

MR. JOHNSON:

Q. Yes, sir. This, and I'm referring in particular to your sensitivity summary table, point number 2, annual load decrease by 880 gigawatts. Was that your intent at looking at

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the Corner Brook situation?
MR. KAST:
A. Mack Kast here. I suppose the answer is yes, but I don't want it to be absolutely attached to the Corner Brook -
MR. JOHNSON:
Q. No, okay.
MR. KAST:
A. It might be better put that it's reasonably representative of Corner Brook.
MR. JOHNSON:
Q. That's fine, that's fair.
MR. KAST:
A. Okay.
MR. JOHNSON:
Q. And then below at .10 you ten combine that with a cost over run or capital cost increase for both Muskrat Falls and the LIL by ten percent which basically brought the isolated and infeed option down to sort of a dead heat, at that point. And scenario 10, there's a footnote under it indicating that was MHI derived. So, that was your own calculation, I take it. And these sensitivity summaries that you've listed in your report at Table 14, were

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these summaries that you came up with on your own to apply? Were these the ones you thought were them most pertinent to consider?
MR. SNYDER:
A. For the most part, yes, but they were discussed over a period of time with different people at different times and different meetings and so on. And what we were looking to do is try and put some reasonable bands around the base case differential, if you like. And so we see numbers like 25 percent, 20 percent and 10 percent because that's what a reasonable person would likely do and understand and appreciate.
MR. JOHNSON:
Q. In terms of case number 8 which would imbed an assumption that Labrador Island Link and Muskrat Falls capital cost increase by 50 percent is--the 50 percent was chosen because it happened to the outer bound of the DG 2 estimate.
MR. SNYDER:
A. That's correct and I appreciate there has been discussion on this and it is the outer limit and we all know that. And so you can accept

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this--you know, bring your own interpretation to it in that respect.
MR. JOHNSON:
Q. Okay. In terms of what we've heard about made it a limited probability of being out there if you have a good DG2 estimate.
MR. SNYDER:
A. Well, I would expect--what we want to be doing is looking at DG3 and where that number ultimately ends up.
MR. JOHNSON:
Q. Yes, okay. I think, Mr. Chairman, it's sort of late in the day and I might profit from having a look at my notes and coming back and finishing up without too much more time tomorrow morning.
CHAIRMAN:
Q. Okay.
GREENE, Q.C.:
Q. One of the suggestions discussed earlier was the possibility of starting tomorrow at 9:00, tomorrow is the last day set aside this week to conclude these presentations. We're not sure, we haven't had the opportunity of a counsel meeting to discuss the anticipated

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schedule tomorrow, but we had previously raised the issue of getting a little bit earlier start at 9:00 if that would help ensure that we concluded by the end of the day.
MR. JOHNSON:
Q. Well, for my part, I don't anticipate being a great deal longer with MHI.
O'REILLY, Q.C.:
Q. Mr. Chairman, I don't see--if we start at 9:30 and based on what I'm hearing from Mr. Johnson, I don't anticipate we're going to have any difficulty in concluding within the ordinary hours of sitting. I don't think we're going to have any difficulty in finishing that.
CHAIRMAN:
Q. We shall adjourn until 9:30 tomorrow morning. Thank you.
O'REILLY, Q.C.:
Q. Thank you.
Upon conclusion at 4:51 p.m.

CERTIFICATE

I, Judy Moss, do hereby certify that the foregoing is a true and correct transcript of a hearing of the Muskrat Falls Review herd before the Board of Commissioners of Public Utilities on the 15th day of February, 2012 A.D. in the city of St. John's, Newfoundland and Labrador and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, NL this

15th day of February, 2012

Judy Moss

Discoveries Unlimited Inc.

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