YUKON UTILITIES BOARD

YUKON ENERGY CORPORATION 20 YEAR RESOURCE PLAN

APPLICATION TO THE YUKON UTILITIES BOARD

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BEFORE BOARD MEMBERS:

Wendy Shanks	A/Chairperson
Brian Morris	Member
Richard Hancock	Member
Michael Phillips	Member

BOARD COUNSEL:

Renee Marx

BOARD STAFF:

Pat Wickel &	
Dwayne Ward	Technical Consultants
Deana Lemke	Executive Secretary

APPEARANCES:

Yukon Energy Corporation	John Landry
	David Morrison
	Cam Osler
City of Whitehorse	Wayne Tuck
Utilities Consumers' Group	Michael Buonaguro
	Roger Rondeau
Yukon Conservation Society	J.P. Pinard

TRANSCRIBER:

Doug Ayers Reporting Services

(Proceedings resumed at 3:15 p.m.)

YEC PANEL RESPONDS TO UNDERTAKINGS:

THE CHAIR: Mr. Landry.

MR. LANDRY: Thank you, Madam Chair, I would like to apologize for being a little tardy in getting this information, but I think we now have answers to all of the undertakings that are still on the record.

So, I will would go from my list, and, of course, we don't have transcript page numbers, but the first two were requests, or undertakings, for Mr. Buonaguro, and the first one related to questions arising out of Exhibit B-22 that was filed this morning, which was a response to an undertaking, and it dealt with the issue of certain costs, as I recall it, on a yearly basis, but, in any event, Mr. Osler is going to deal with that one.

A MR. OSLER: There is also a question he had about secondary sales, and I will deal with the two together.

MR. LANDRY: In fact, what we can do is, because the second undertaking, which will show up in the record, does deal with the issue of when you take into account secondary sales, how does that affect the analysis, so those were actually

two separate undertakings, but I think Mr. Osler can answer both of them, perhaps. I hope.

A Madam Chair, dealing with them in the order in which they arose, the first question sort of generically asked for, well, give me a percentage rate effect, if I got it right, like you have given for the other projects, for this Carmacks-Stewart project, on rates, like in the earlier years, or something like that, because you have done this for the Mirrlees, and you have done it for other things. Is it 2 percent, 3 percent, what is the effect?

Generally speaking, we have not gotten into rate analysis, at all, in terms of rate impacts, because we have assumed that the -- not assumed, the Corporation's policy position on this project has been it will not be developed unless -- if it has any adverse effect on rates. So the bottom line is, it will not make rates go up if it is developed.

In terms of, in the spirit of the question, though, so given, say, Stage 1, a development of the type that was talked about in Exhibit B-22, and talking about the first full year of operations, the effect on revenue requirement of the type of midpoint capital costs we were talking about today,

in these exhibits, for Stage 1, depreciation, rate base return, would be in the order of magnitude of $2 million.

Ignoring anything else other than just what was in the exhibit, the revenues that we were talking about in that exhibit, with all of the limitations that are talked about there, in Stage 1, was about 3 million, in the first year, from the mine, and 325,000 revenue, from cost savings from Pelly Crossing. So you can see that there is a positive, just from those types of hypothetical numbers, but there is a positive benefit, and if you translate it into a percent on revenue requirement, and using the numbers we have used in this submission, it would be in the order of magnitude of 2 percent; 2 percent or a bit higher.

Generally, I want to emphasize, and that gets me into the secondary sales issue, that, with the Carmacks-Stewart, we are at a stage of planning and decision-making assessments, but given the nature of this project and the commitment I just underlined, that has been there from the beginning, the question comes down, very definitely, to the final arrangements. At one time, we thought with Yukon Government would be the focus; in this case, now, it will be with the mines, as to how this

project translates into a situation for the Board to review in a PPA.

And things we have deliberately not put forward evidence on include effects on secondary sales, because they would get into a lot of estimating issues, and effects on fuel and operating costs for what happens on the system, because they get into other types of complexities, and they also may be covered off in how we negotiate PPA arrangements.

I would tell you that, if you are interested in exploring those things, you should review evidence which was filed, for separate reasons, in Appendix C of Exhibit B-1, where there were detailed tables put in year-by-year, sort of way back a year ago January, last year, when the analysis was being done, of base load and peaking diesel generation on the WAF system, with and without the mines with 10 megawatts, which was the Minto and Carmacks Copper mines. You should review Table C-2, which is the situation without the mines, Table C-3, the situation with the mines, and you will notice that base load diesel requirements emerge, as well as significant peaking requirements, and the effect of Aishihik turbine on moderating that. You should review Exhibit C-7,

which talks about the effect of the Carmacks-Stewart connection, on top of all of those things.

So there is a lot of complexities in that area that, really, we have to deal with in negotiation, in PPAs, to make sure that the ratepayers are held harmless, in order to meet the basic commitment that the Corporation has made from the beginning, if this project is going to be developed.

MR. LANDRY: I understand that Mr. Rondeau has indicated, and unfortunately I just do not have it in front of me here, that the reference that I gave earlier, to B-22, should be B-23, just so the record is clear. But in any event, I think it will come from the transcript, because counsel for UCG would have referenced it, and that is the one we were responding to.

Okay, the next one that I have on my list, Madam Chair, was a request for a correction to the attachment to YUB-YEC-2-14, and it is Attachment Number 1, and I think Mr. Campbell will provide that information.

A MR. CAMPBELL: Thank you. Yes, there certainly is a correction, as I pointed out this morning. The January the 24th, 2006, 0:100 hours reading should be 3096, or 3,096 kilowatts, instead

of 6,157 kilowatts. In our review, we did find one other typo as well, and that is back on August 18th, 2005, at 19:00 hours, the reading should be 3,048 kilowatts instead of 30,478 kilowatts.

MR. LANDRY: Madam Chair, the next one I have is an undertaking that Ms. Marx requested, which was the list of dispatching order for the diesels, and Mr. Campbell, I think, is going to deal with that.

A There is a handout for this. I thought it was much easier handing out the dispatch table than trying to explain it. So if I could explain the table very briefly, the table lists the diesel generating units on the WAF grid in the preferred order that they would be dispatched, or operated, by our system operators. So the stacking order, the Number 1 unit would be the unit first on, the Number 2 unit second on, and so on. So, indicating WD7 is one of the newer CAT 3600 modules at Whitehorse, that would be the first unit lost by virtue of its fuel efficiency, lower maintenance cost, lower lube oil costs and so on. The actual dispatch is done on the line loss adjusted cost per kilowatt hour on the right-hand side. I would note that, under the current standby back-up operation, we are not actually making a line loss adjustment

for the location, it is assumed they are run primarily in a back-up mode, so the unit in the community, or the nearest location to where it is needed, would be the one run, to some extent.

As well, there are a couple of manual adjustments made, out of a pure economic dispatch order, that, again, simply reflect the current operation today, primarily as a standby back-up mode.

MR. LANDRY: The last -- is that finished?

A Yes. Of relevance may be the types of numbers, and they do reflect the numbers that Mr. Morrison was talking about, and other people of the panel, that, effectively, the operating costs of the diesels today are between 20 and 25 cents a kilowatt hour, excluding the original capital cost.

MR. LANDRY: I wonder if you could mark that as the next exhibit, Madam Chair.

THE CHAIR: That would be B-23, so marked.

EXHIBIT NO. B-23:

DISPATCH TABLE.

MR. LANDRY: The last undertaking, as I have it at least, is, again, an undertaking requested by Ms. Marx, and it relates to impacts --

rate impacts for each of the projects. The projects I had listed were the Mirrlees, the Carmacks-Stewart line, Aishihik Number 3 Turbine, and also the Aishihik twinning, and I think Mr. Bowman has a handout to deal with this.

A MR. BOWMAN: The undertaking was requested in reference to the update -- or the summary document, and a chart therein that showed the residential non-government bills for Yukon compared to other places, and we were asked to look at a bill comparison that fit that type of context related to the projects, so what would be the impacts on the bills paid by residential non-government customers as a result of the projects proposed in the Resource Plan.

As you can well appreciate, the Resource Plan looks at overall utility system costs, and, as they change with various projects, there is a lot of things that happen between the utility's cost, and its revenue requirement, and its ultimate bills that relate to cost of service, and revenue cost coverage ratios and a number of other things, rate rebalancings, as well as different riders that occur. So it is not -- one cannot perfectly correlate between the two.

What we have done, though, is we have taken

the context of a bill, for Yukon, for our non-government residential customer which, absent GST and absent Rider F, which is a special rider solely to do with the price of diesel fuel, would be $126.45 a month before one gets into government subsidies, so ignoring the RSF subsidies. And looking at the overall type of revenue requirement impacts of the projects proposed, we have taken those simple percentages that arise on the revenue requirement, applied that to that bill, to give an idea of the order of magnitude we are talking about with regard to bill changes that would occur to residential non-government customers.

So what this table does is, it deals with each of the -- it deals with the Aishihik Third Turbine, as well as the three projects proposed to deal with capacity shortfalls, or the three projects noted as options to deal with capacity shortfalls in the Resource Plan.

In regards to the Aishihik Third Turbine, as requested, this deals with the assumption you build the Aishihik Third Turbine absent all other projects, so simply that turbine, or not, and with the base case load and no mine loads. That would lead to, and it is consistent with what is shown in chapter 4, a rate impact of about 1.86 percent, as

of the time it came into service, which is assumed in this as at 2009; a 1.86 percent overall change on the level of utility costs. And flowing that 1.86 percent through to a bill in a linear way, a bill of $126.46 a month, the monthly bill impact on residential customers would be about $2.35 at the outset of the project.

Now, what I have also done to show how these different projects change differently over time, as Mr. Osler noted when the undertaking was requested, I have taken one other date further out in time to show the impact at that point in time, and this is in regards to the Aishihik Third Turbine. It emphasizes that the impact of the Aishihik Third Turbine, on bills, turns around, by that point in time, and is a factor that leads to a reduction in bills, compared to not having the project, of 2.54 percent, which would equate to $3.21 per month. And that all comes out of Appendix C, and it is Table C-1 in Appendix C, the basic case of the Aishihik Third Turbine. Those numbers change a bit as you add mines, or as you add the different projects.

The other three projects are grouped together because they are -- unlike the Aishihik Third Turbine, they are not projects that are proposed to

be pursued for cost saving or for -- based on the opportunity they provide. They are projects that are proposed to be pursued in order to provide the needed capacity on the system, and in effect, if one is going to meet the capacity criteria, you have to deal with one of these three, primarily.

They have been largely benchmarked to approximately the same capacity contribution, although the Aishihik second transmission line is a little trickier to do that with. But just to go through it, if one is looking at what we call the Whitehorse Diesel Replacement, so installing new diesels in Whitehorse, and in this case it would be installing 18.7 megawatts of new diesel, which is the amount required by 2012, this assumes it would be installed over the period about 2007 to 2010, as the shortfalls arose. And when you look at the depreciation and return costs related to those, compared to current bills, the rate impact would be about 4.79 percent, or about $6.06 per month, for residential customer bills.

Over time, that rate impact goes down because you depreciate the units. So looking simply at 2020, with no inflation on the bills, or anything, still using at $126.45 per month bill, the rate impact would have dropped to about 3.35 percent due

to depreciation on the units by that point. So the bill impact would be down to $4.24 per month. And those are not a cumulative increase, those are the overall impact at that time.

In comparison, the Mirrlees Life Extension, which is based on -- it is using 8.7 million here, because it rolls in the Faro unit. We had been talking 6.4 for the three Whitehorse, plus a comparable cost for the Faro, which would put it at 2.3 at the planning level estimates. So 8.7 million for 19 megawatts, very similar to the Whitehorse diesel replacement scenario. And the bill impacts are, likewise, shown; 2.62 percent over the period that they come into service, which is $3.31 per month, declining over time, and by 2020 it would be about 1.84 percent, or $2.33 per month.

The Aishihik second transmission line, looking solely at the capital cost impacts, which are the bulk of what arises, is an option to -- a third option compared to the two we went through. The amount of capacity it provides, as noted in the bottom in italics there, depends on the particular scenario one is under, whether you are being driven by the N-1, or the LOLE scenario, and whether you have built the Aishihik Third Turbine already, or

not.

We were asked to do this based on each project individually, so I noted what it would be if you had not built Aishihik Third Turbine. But that the highest capacity it provides, in a planning context, is if you built the Aishihik Third Turbine, and you are still, otherwise, being driven by the N-1 criteria, in which case it is 22 megawatts.

Putting that line into service at the cost estimates that were in the Resource Plan as filed in January, of 16 to $19 million, would have a rate impact of 4.63 percent as of the time it comes into service, or about $5.85 a month, and as you depreciate the line similarly to the others, it would come down. It doesn't depreciate quite as fast as diesels, transmission lines have a bit of a longer life, so it depreciates down to about 3.68 percent, or $4.65 a month.

The notes at the bottom set out, for those who are interested in the mathematics, how these are calculated, based on the assumption that $360,000 in revenue requirement reflects 1 percent overall change in the system costs. We did not go on and try to put this into the graph format, in part because the graph, as there, already has -- plus we

didn't have enough time -- in part, because the graph there has these other factors, like Rider Fs and rate stabilization funds in it, so it would have been a little bit harder to disassemble that and, in part, because these type of numbers would be -- they would be hard even to show up in the graph, in terms of that level.

But overall, on a bill of $126 a month, you can see the various impacts. And it underlines the point that has been made, that although the Aishihik second transmission line, in particular, has very specific benefits, it's the cost comparison to the Mirrlees that has been driving the recommendation in the Resource Plan -- the proposed projects.

A MR. OSLER: Just to add, before the question arises, the Carmacks-Stewart line is not on this sheet, because of these points I raised a few minutes ago in answering the earlier question, which we knew would come first. So the answer to do with the Carmacks-Stewart is on the record. It is not to be developed if it has any adverse effect on rates, and we don't want to get into, beyond what have I said, into trying to estimate the outcomes of all of the complexities that I was just talking about.

MR. LANDRY: Madam Chair, can we mark that as the next exhibit, which, I guess, is B-24.

THE CHAIR: So marked.

EXHIBIT NO. D-24:
HANDOUT RELATED TO RATE IMPACTS FOR EACH PROJECT.

MR. LANDRY: And just for the record, I did find the exhibit that we were referring to earlier this morning, it was B-22, actually.

Now, the last item, I understand there is a connection, Madam Chair, to something, to some information provided relating to the rewind of Aishihik Number 1 and Aishihik Number 2, that Mr. Campbell would like to make, so ... Mr. Campbell.

A MR. CAMPBELL: Thank you, yes. The correction relates to the information that the company provided, I think on page 402 to 405 on the transcript, and it is with regard to the discussion on the Aishihik rewinding the units, and the potential re-rating of the units. There is some confusion. I wanted to clarify exactly for the record what the actual improvements were, electrically, and what the potential is mechanically.

First, we were incorrect when we said that the rewinding of AH1 did not result with an increase in the capacity rating. Second, we wanted to clarify what we meant when we said that the work done on AH2 somehow provided for an increase in capacity that we did not get when we rewound AH1.

On the first issue, in fact, Yukon Energy, we were able to get mechanical capacity increase as a result of rewinding AH1. It was a modest increase, as we reported in one of the IRs, that we now feel that that unit is capable of 15.4 megawatts.

In relation to the second unit, AH2 has not resulted, as yet, in an additional mechanical capacity rating above that of AH1, for the reasons that we spoke of yesterday, and the fact that we have not recommissioned the mechanical side of the units at this point in time. There is work under way between now and the spring, where we do hope to be able to recommission that unit, potentially as much as 1 to 2 megawatts higher than the 15.4 megawatt rating that we now have a mechanical rating for, for Unit 1.

With respect to why the difference, AH1 was rewound by the original equipment manufacturer, General Electric. And, in fact, when their work was done, we did ask the manufacturer to scope the

work to give us the maximum capacity that they would be able to achieve. And, in fact, that was done. When the work was done two years later. For the second unit, the work was awarded to a different vendor who, in fact, was able to guarantee a higher rating, electrical rating, of the unit. And we feel while, electrically, potentially there is 1 to 2 more megawatts available electrically, right now on that unit, if we are able to achieve it mechanically, then we will at that point be able to recommission Unit 2 as high as 17 to 17 and a half megawatts. Of course, that mechanical increased rating is not possible with the first unit because, again, electrically, the vendor, when the rewind was done, was only able to guarantee it up to the 15.4 megawatts rating.

MR. LANDRY: Just to follow up a couple of questions so that the record is clear, Madam Chair, if I may, with Mr. Campbell.

THE CHAIR: I beg your pardon?

MR. LANDRY: Just a couple of follow-up questions to make sure the record is clear on this point.

AH1, at this moment in time, has what mechanical capacity rating?

A 15.4 megawatts.

MR. LANDRY: And AH2, what mechanical capacity rating --

A Effectively the same, 15.4 megawatts.

MR. LANDRY: So that adds up to the 30.8 megawatts that's in the Resource Plan?

A Yes, that is correct.

MR. LANDRY: Madam Chair, those are all of the responses and/or corrections, and as we indicated, if there are any questions arising out of those, we are more than happy to have the panel answer them.

THE CHAIR: Thank you.

Mr. Buonaguro, it looks like you have some questions.

MR. BUONAGURO: Thank you.

YEC PANEL CROSS-EXAMINED ON UNDERTAKINGS BY MR. BUONAGURO:

Q MR. BUONAGURO: My first question, I think the answer was, for the first year of operation, the equivalent revenue requirement for the Carmacks-Stewart transmission line was $2 million, or approximated at $2 million?

A MR. OSLER: About $2 million, as just declining balance, yes.

Q And what about year two to the life of the line?

A It is over 50 years, and the numbers go down as the way it would have done for the Mayo-Dawson. We have not bothered throwing out that type of analysis, but it goes -- by the time it gets to the end of its life, it is zero, and it is linear.

Q Can you give me the numbers for the -- you gave me numbers -- or, sorry, the benefits that you projected were, I think, were to 2025 for the benefits of the system. Could you project that $2 million out to 2025 so I have the matching?

A I could get you the Stage 1 cost, that we have here, done the way we have just described it. We will file that, out to 2021 if you like.

Q It sort of begs the question of what happens to Stage 2.

A Well, no, but --

Q I guess Stage 2 gets rolled in later and starts later?

A Stage 2 costs, when they occur, would have the effect that those costs have on the revenue, and be net of any contributions from government, et cetera.

So the point of view of a rate effect, what I am trying to get across, is that the Corporation's commitment is not going to develop the project if there is an adverse rate effect. And I am not able

to help you as to the extent to which there would be a positive rate effect. And so the exercise in the end, I am not very -- I cannot be helpful to you at this point in time. I can give you the stream of numbers you asked for as the costs, to tell you the hurdle that is there, and I could do the same with any other stream of numbers you want. But all it does is tell you what we have to make sure we find benefits for to offset it.

Q And that is actually precisely why I asked the question. I would like to know, on a yearly basis, what hurdle it is that you have to overcome, in terms of accruing benefits, in order to offset them. You have identified exactly why I have asked the question.

A We can provide -- we will file that as -- after the hearing is over, we will provide that.

Q And can you do that for Stage 2 as well --

A We will --

Q -- based on your projected or preferred start date?

A We will take the numbers that were in the exhibit I filed this morning, there is a Stage 2 set of costs, and we will assume they start in 2009, and we will do the same things to them. But I won't get into trying to discuss revenues or benefits or anything. It will just be the costs. It won't be

a rate impact effectively.

Q I understand what you are saying, and I understand the qualifier. And as I understand, the qualifier is -- we want negate the effect that you are asking me to illustrate, I understand that. But I want to know what it is that you are trying to negate, either through government funding or through benefits in your lines. I understand that, thank you.

A I am also saying that the project just won't be developed unless the Board of Directors of Yukon Energy is confident that these costs will be offset, period.

Q That is fine.

The only second question I would have, actually, would be with respect to Ms. Marx's undertaking, but maybe I will let her -- if she has any questions on Undertaking 12.

MS. MARX: On which undertaking?

Q MR. BUONAGURO: It has to do with the fact that the Carmacks-Stewart line isn't included in this. It is a different way of asking the same question, I guess. And illustrating what would be the monthly bill impact, for the Carmacks-Stewart line, on Undertaking 12, basically adding it in, and understanding that you are trying to negate

that through various means.

A MR. OSLER: It will be zero or negative, or it won't be developed.

Q Right. And I asked the question for the same reason. I want to know what it is that you are overcoming, what bill impact you are trying to negate through government funding or through mine profits or --

A I think you have asked me a question that, technically, I can answer. If you get me into a rate impact table, the answer will be zero or less, or it won't be developed.

MR. BUONAGURO: I take it I won't get anything more than that.

THE CHAIR: Is that the extent of your questioning.

MR. BUONAGURO: Yes, thank you.

THE CHAIR: Ms. Marx?

MS. MARX: I actually do not have any follow-up, thank you.

THE CHAIR: Mr. Landry?

MR. LANDRY: Madam Chair, I have a number of questions in redirect, and I have a number of notes on them, so just give me a second on each one so I can make it clear for the record.

YEC PANEL RE-EXAMINED BY MR. LANDRY:

Q MR. LANDRY: The first question I have, and I think Mr. Bowman would probably be the appropriate person, given the questioning that he received on the issue of forecasts, the forecast growth, and there was a number of questions from UCG's counsel, and also counsel for the Board, on this issue, and, at the end, you made a comment in response to a question, Mr. Bowman, something to the effect that the load forecast that's in here really does not have a material impact -- and those are my words, not yours -- on the projects that are being proposed here.

Do you recall at least those questions that were asked in relation to that?

A MR. BOWMAN: Vaguely, yes.

Q I know that this was dealt with in the record, somewhere, in terms of forecast. Do you know what IR that was answered, that effectively dealt with that issue?

A If I understand the question, the issue is of the load forecast and the extent to which the load forecast is driving or is underlying the need for the projects in the Plan. We dealt with this, to some extent, in UCG Question Number 43. It is actually in a footnote. It is not the most fascinating thing to read on the fly, but I can

summarize for you.

Q Would you do that, please.

A In the period of the Resource Plan, we are talking about facing a capacity shortfall, compared to the criteria that has now been adopted, and reflecting the retirement of the Mirrlees, of 18.7 megawatts. It is a number that has been used a number of times.

That 18.7 is the number to 2012. Of that 18.7, far and away the driving factor is the adoption of the new capacity criteria and the retirement of the Mirrlees. The only component of that 18.7 that is related to differences in load forecasts between now and 2012, and the extent to which it is 2 versus 2 1/2 versus 1 1/2, is about somewhat less than 25 percent. So in other words, even under the low forecast scenarios, we are talking about shortfalls in the order of 15 megawatts; in other words, the entire fleet of Mirrlees that we are talking about. So this goes to my comment earlier, that in many cases, when you are sitting looking at a long-term Resource Plan, and people who follow the utility industry will know this in spades from the '70s and '80s and old NCPC plans, or Ontario Hydro, the Plan really hinges on what rate of growth are you going to

assume. And if you have a high rate of growth, you get a completely different development scenario than if you have a low rate of growth. And people spend a lot of time debating that.

In this Plan, it is not like that at all. Very little of what is in the Plan, particularly in the near-term projects, relates at all to debating those particular load forecasts.

Q Thank you. The second question I have is to Mr. Morrison, and it relates to questioning that you had both from counsel for UCG and the Board counsel, relating to the NCPC report that was done on the Mirrlees. Mr. Morrison?

A MR. MORRISON: Yes.

Q Since NCPC did its report, you indicated to the Board on a number of occasions that you have done further work with the manufacturer, et cetera. Have you had any other technical people, outside of the company, look at this issue of whether or not the Mirrlees should be appropriately refurbished?

A Madam Chair, yes, we have. We have had two additional examinations. We had a consultant, Mr. Mack Brody, who has some 40 years experience, is currently involved in the construction of a large generating plant in Alaska. He has -- I am certainly happy, if it is helpful, to submit his

C.V. for the Board, but let me tell you, I think he has an expertise, in my mind, that we would be hard to find in North America. He is an electrical engineer. He has a strong utility background. He came and looked at the engines for us as well, and the plant. And his view was that there was no reason that these engines could not be refurbished.

In addition to that, I understand that we have a report from the Northwest Territories Power Corporation. But we had the former operations manager from the Yellowknife region for Northwest Territories Power Corporation, who has retired, who is a Mirrlees factory-trained mechanic. He was one of the original four Mirrlees mechanics that NCPC hired from the factory in England when we bought the engines. I am trying not to say that I was there when we bought them, and give away my age, because that was 35 years ago. So when we brought these engines out, Mr. Chris Chatwood was one of the mechanics that we brought along. I do not mean it to be humorous, but it is a bit ironic that not only did we have to buy the engines, but we had to hire the mechanics, that came from the factory, along with them. You just could not get a diesel mechanic to work on them. They had to have their

own mechanics.

But he, most recently, had a look at them. And I think I mentioned yesterday that we have gone to the extent of pulling the cylinders on the unit in Faro and one of the units in Whitehorse. And it was particularly important to me that, because the MAN Diesel folk in Toronto had indicated to us that that was a certain sign, if there was scarring or scoring in those cylinders, that that was a very specific sign that there may be problems. And so we had Mr. Chatwood come up from his home in B.C., once we pulled these, and he worked with our mechanics, and they looked very thoroughly inside the engine, and his conclusion was clearly that the Mirrlees -- he had no hesitation and he saw no reason why we couldn't go ahead with these overhauls.

Q Mr. Morrison, just on the Mirrlees, and there were a number of questions on the January 2006 outage, how did the Mirrlees -- how did they fare in that outage?

A Well, they were very important to that outage, you know, it's 11.4 megawatts of capacity, and they all came on, they all ran as expected once they were turned on.

Q I want to ask a couple of questions concerning the

discussion you had regarding the January 2006 power outage. And I guess the first thing I would like to do, Madam Chair, for the record, given that there were a couple of responses that referred to it, and that is to mark a document that was referred to but it is not on the record as of yet, which is the letter to the Board from Yukon Energy, relating to that outage, which is dated April 11, 2006, and my colleague is handing out copies to it. So I would like to mark that for the record, please?

THE CHAIR: Yes. Do you have a number? Have you already numbered it?

MR. LANDRY: I think it is B-25, if I have that right.

THE CHAIR: So marked.

MR. LANDRY: Thank you.

EXHIBIT NO. B-25:
LETTER DATED APRIL 11, 2006, FROM YUKON ENERGY TO YUKON UTILITIES BOARD.

Q MR. LANDRY: Now, I do not want to go through this in any detail. I really want to refer Mr. Morrison to an answer that you gave to one of the questions, which indicated that you were able -- Yukon Energy was able to get the power

back, and I think the approximation was to 12 or 13 hours after the Aishihik line went down. In order to bring that power back, in the 12 or 13 hours, did any of the power that you got back come from the Aishihik line?

A MR. MORRISON: No, not originally, the line was out.

Q But when you brought it back, what was the power that was used to --

A Well, we put the system back on with the hydro plant at Whitehorse, and all of the diesels on the WAF grid, including Faro and the Whitehorse diesels.

Q And how long was it before you were able to get the Aishihik line fully back on line. When I say "fully back on line" ... not derated in any manner. How long did that take?

A Not derated?

Q Right.

A Three weeks.

Q So it took three weeks in order for the Aishihik line to fully come back on line to the system?

A That is correct.

Q And during that time, from the time you brought the power back on, 12 or 13 hours after the outage was out, to February 21st, you were able to provide

power to all of your customers?
A Yes, and that is what I meant when I said that it took us 12 or 13 hours to get the power back on. We had some customers on in about three to four hours. It took us 12 or 13 hours to get all of the customers back onto the system.
Q Now, sir, I want to -- given that, I want to give you an assumption, and I would like you to comment on it. I want you to assume that the N-1 criteria is not approved, and you have a similar outage, at a similar time, on the Aishihik line, and that the Mirrlees, which are scheduled for retirement, are retired, and no new capacity is added to the system. How long would it have been before you would have been able to restore power, in such a circumstance, to everybody on the system?
A Well, Madam Chair, let me start by saying that if the N-1 criteria isn't there, and we have -- and we lose essentially 11.4 megawatts of diesel because we retire them and we don't replace them, first of all, I don't know how I am going to sleep at night in the winter, because the -- if the N-1 scenario happens, it, essentially, originally means we cannot fully supply the load, period. We would be 11 -- let me go back and try to do pretty simple math.

We have 87 megawatts of capacity on the WAF grid, fully supplied. If we lose the Aishihik line again, either the plant or the line, in totality, we are down to 57 megawatts. In recent years, so within this last couple of years, we have been in the 56 megawatt peak range. Well, that leaves us one extra megawatt, given that everything works, always. But you know, so we are -- basically, we are right at the margin.

So if you are asking me how we deal with the scenario of losing a further 11 megawatts, until such time as that Aishihik line could come up, or could be brought back on in full service, we would be 11 megawatts, 10 or 11 megawatts short, and would be in a series -- and very significant rolling black-outs in the system for the entire period of time that line was down. We would not be able to supply. And that would be a serious issue, from our perspective. It would be an almost impossible situation, over time, in terms of trying to operate that system over any length of time.

I think, you know, from our perspective, given that we have lost a line a couple of times, and you know you could take -- you could take the position that, well, you know, if you play the odds, well, we have already lost it, so you know, are the

chances smaller that you will lose it again? Having gone through that scenario, I do not think it would be -- it certainly would not be responsible, on our part, to put ourselves in that position, and I think it would be a horrendously difficult situation for us all to face every winter, knowing that we did not have enough capacity to meet that inevitability.

Q I would like to turn now to -- I think it will be Mr. Bowman that might be able to respond to this question, and this was a question that effectively arose out of an answer that Dr. Billinton gave to Board counsel, and it relates -- I will give the transcript reference -- at least I think I am going to be able to give the transcript reference. Yes, it is transcript page 369, and it was questions in relation to Figure 2.4, which was from Dr. Billinton's report, in YUB-1-1, and Figure 2.4 was at page 15 of 60.

And Mr. Bowman, maybe can you help me here. If you could get that in front of you. The question was -- and I am reading from line 9. Counsel was looking at, or discussing the graph that was there, showing peak, and it says:

"Question: Now, am I correct to assume from that, that the load is at or

above .9 of the peak only for a very short period of time?

Answer: That is true. In most systems, that is the case."

And it arises out of that answer, Mr. Bowman. And I guess what I am wondering about is, in your experience, from a planning context, even though the peak is only for a short period of time, what do -- how do you understand that the utilities, for example, in North America, deal with that issue? How do they capacity-plan for that issue?

A MR. BOWMAN: Mr. Landry, I can speak to a couple of cases. I certainly have not done surveys of the type Dr. Billinton has. I do note that he went on to say that the NERC criteria, which is used throughout North America, does deal with the peak, not the peak most of the time. It is focused on the 100 percent peak, not just the 90 percent, for example. I also note that these graphs are somewhat -- can be a bit misleading. It is correct to say that it is not much of the year that you are above 90 percent of the value. But not much of the year, when you have 8,700 hours a year, this graph -- that point is probably about 200 hours of the year that you are above that. So it is not much of 8,760, but it is not 20 minutes

either. It is a fairly substantial amount of time, over the course of a winter, that you are up in that range.

Having reviewed the types of planning that is done in the jurisdictions where I have worked, Newfoundland, Manitoba, and, in particular, Northwest Territories where I was involved in the same hearing Dr. Billinton was referencing, in each case, you are talking about "the peak", not "the peak less some factor", because it doesn't happen very often. In fact, in Northwest Territories, it is based off "the peak" plus 5 percent for uncertainty, load forecast uncertainty.

Q Are you aware of any jurisdiction in North America that capacity-plans below the peak?

A No. And we did, as part of the workshop Dr. Billinton mentioned, we did talk about whether one -- whereas Northwest Territories used 105, to me, I come from a mathematical background, so 105 is just a number, and 95 is as good a number. But I can relay that the professionals in reliability planning, at the workshop, were not in agreement. 100 percent is the peak, not some ratio of it in order to derate it. That is a peak you know you are going to expect to need to serve, especially where it is one you have experienced, that is the

one that you plan to.

MR. LANDRY: Madam Chair, those are all of the questions in redirect.

THE CHAIR: Thank you. I guess at this point we can excuse the panel.

Are there any other parties that have any other matters before the Board? In which case, I believe that concludes our hearing, and we will look for written argument to be provided to the Board by November 24th, with written reply argument by December the 21st.

I thank all parties for their participation -- December the 1st.

MR. LANDRY: I was hoping.

THE CHAIR: And I thank all parties for their participation, and we look forward to your written argument. We will adjourn now.

(Proceedings concluded at 4:10 p.m.)

REPORTER'S CERTIFICATION

I, the undersigned, hereby state that the foregoing pages 1 through 546 were taken down by shorthand and transcribed to the best of our skill and ability.

DATED at the City of Whitehorse, Yukon Territory, this 16th day of November, A.D., 2006.

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Doug Ayers,

Court Reporter

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