YUKON UTILITIES BOARD

YUKON ENERGY CORPORATION

WHITEHORSE DIESEL TO LIQUEFIED NATURAL GAS

CONVERSION PROJECT (LNG PROJECT)

P R O C E E D I N G S

Volume 1

March 31, 2014

Whitehorse, Yukon

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March 31, 2014

Mr. B. McLennan	Chair
Mr. R. Laking	Vice-chair
Mr. N. Prasad	Board Member
Mr. A. Fortin	Board Member
Mr. R. (Les) Boisvert	Board Member
Ms. G. Bentivegna	Board Counsel
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Mr. J. Maissan Ms. A. Middler	Leading Edge Projects Inc. and Yukon Conservation Society
Mr. M. Janigan	Utilities Consumers' Group
Mr. D. Roberts	In his own stead
Ms. A. Jones, CSR(A)	Official Court Reporter
Ms. D. Gerbrandt, CSR(A)	Official Court Reporter

(Proceedings commence at 9:10 a.m.)

THE CHAIR: Good morning. Please be seated.

So good morning, everybody. I'm calling this hearing to order. My name is Bruce McLennan, and I'm chair

of the Yukon Utilities Board, and I'd like to introduce the Board members sitting on the Panel with me. To my left are fellow Board members Naresh Prasad and Bob Laking, who is the vice-chair, and on the right are Les Boisvert and Andre Fortin.

Today starts the public hearing phase of the Yukon Energy Corporation's (YEC) application for an energy project certificate and an energy operation certificate for the Whitehorse Diesel to Liquefied Natural Gas Conversion Project, also known as the LNG Project.

These certificates are applied for under Part 3 of the *Public Utilities Act* and have been referred to the Yukon Utilities Board for review and hearing in accordance with the terms of reference prescribed by the Minister of Justice in his letter of December 18th, 2013.

On December 9th, 2013, YEC applied to the Minister for the said certificates under Part 3 of the *Public Utilities Act*. Accordingly, on December 20th, 2013, the Minister referred the matter to the YUB for review and hearing. The Minister provided in part the following background information for the terms of reference he provided.

On April 27th, 2012, Yukon Energy Corporation filed with the Yukon Utilities Board an update to its 20-year resource plan, 2006 to 2025, as an interrogatory response to

questions posed by interveners during the review of the 2012-13 general rate application.

In this document it outlined the option of thermal generation using LNG for near-term development. The Whitehorse Diesel to Liquefied Natural Gas Conversion Project is a project to modernize the existing YEC Whitehorse thermal generating station to meet the growing requirements for reliable and flexible thermal generating on the Yukon grid, including the replacement of two diesel generating 9.1 megawatt total capacity scheduled for retirement by 2015, with up to three new modular natural gas-fired generating units, 13.1 megawatts total capacity supplied by LNG, and the installation of LNG truck offloading storage, vaporization, and related infrastructure.

The Whitehorse Diesel to Liquefied Natural Gas Conversion Project has been designated in OIC 2013/200 as a regulated project under Part 3 of the *Public Utilities Act* pursuant to section 36 of that Act.

The Minister, in his terms of reference, stated that the general purpose of the review and hearing is to obtain the YUB's report and recommendations on the potential benefits, cost, risk, and customer impacts that influence whether the LNG Project should proceed as proposed by YEC and any terms and conditions which the Board considers should apply.

The Board was asked to report on and make recommendations about the necessity for the proposed LNG Project and its timing and design with particular regard to the following five points:

(a) the public need for the project under various reasonable electrical load forecasts, including near-term requirements related to industrial and nonindustrial loads and the effect of the project on the rates of customers;

(b) the capability of existing and currently committed generation and transmission facilities including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements and YEC's capacity planning criteria and the effect of the LNG Project on this capability;

(c) the risks facing the LNG Project and their potential impact on rates for customers;

(d) what if any alternatives to the LNG Project might be advisable given reasonable load assumptions and risk assessments;

and (e) whether it is prudent to build the LNG Project at this time.

The Board is to provide a recommendation on whether the energy projects and the energy operations certificate should be granted for the LNG Project; whether

the certificates should be subject to any terms and conditions; and it is to make any other recommendations to provide any other information that it considers advisable in the circumstances.

In terms of oral argument and oral reply, the Board would appreciate if each party would organize its arguments and reply in line with section 3 on pages 2 and 3 of the Minister's terms of reference which are dated December 18th, 2013.

Now, I'd like to turn my attention this morning and introduce the Board counsel: Giuseppa Bentivegna and Board staff Bob Clark and Dwayne Ward. And assisting the Board in administrative capacity during this hearing are Deana Lemke and Colleen Henry.

Now, Deana will only be available for this morning's session and she may return on the other mornings, but Colleen will be here throughout the actual hearing. And the court reporters that are present are with Amicus Reporting.

Parties wishing copies of the transcripts for this hearing should contact one of the court reporters.

Any questions that come up with respect to the procedures or process should be directed to Board staff.

For this hearing we intend to sit from 9:00 in the morning to approximately 5 p.m. each day. We will plan a

midmorning break of about 15 minutes around 10:30, a lunch break from noon to 1:30 p.m. and a 15-minute afternoon break at 3:30 each day.

In order to allow for public input this evening, today we will recess at 4:30 p.m. so the public input can commence at 7 p.m.

I should mention that registered interveners are invited to attend this session and, in fact, encouraged to attend this session, but in accordance with community session guidelines that has been posted on the Yukon Utility Board website and distributed to each party, they will only be allowed to listen to the registered participants' oral presentations.

The Board intends to hear the application as follows: The Board will first hear from the witnesses for YEC, then interveners may cross-examine the YEC witnesses in the order that the interveners are registered.

Board staff and the panel will then ask their questions of the YEC witnesses, then YEC will have an opportunity to re-direct its witnesses to clarify or complete answers that were given during cross-examination or to questions from the Board or Board staff.

Also, YEC, as the applicant, will have an opportunity to present rebuttal evidence. Rebuttal evidence is a limited opportunity for the applicant to address any new

issues that have come forward in the course of the hearing. Rebuttal evidence is not an opportunity for the applicant to introduce new evidence or to shore up evidence that has already been presented.

At the end of the evidentiary portion of the hearing, the Board will proceed to oral argument and reply as indicated in Board Order 2014-01.

Before I conclude, I just want to remind parties about the appropriate use of aids to cross-examination during this hearing.

The purpose of an aid to cross is to assist the parties questioning a witness about the evidence of that witness. An aid to cross-examination should only be used if it assists in the questioning of a witness.

Questions that can be put to a witness directly should be asked without the use of an aid to cross-examination.

The party proposing to question the witness should submit a copy of the aid to cross-examination to the witness counsel at least 24 hours prior to using the aid to cross-examination. Providing the aid to cross-examination to the counsel before the witness testifies allows the witness an opportunity to become familiar with the document and results in a more efficient hearing.

The party questioning a witness does not

submit the aid to cross-examination to the Board at the time it sends it to the counsel for a witness.

If a party brings forward its aids to cross-examination during its questioning of a witness, the party must distribute sufficient hard copies to the Board and Board staff immediately prior to asking questions in relation to the aid to cross.

The party, after questioning the witnesses, asks the Board to give the aid to cross-examination an exhibit number. The Board will then decide whether the aid to cross will be filed and given an exhibit number which is obviously for the purpose of keeping track of this document.

If the Board gives the document an exhibit number, then it also needs to be provided to the Board executive secretary in electronic format at that time.

To facilitate efficient marking of exhibits, the executive secretary of the Board has circulated a list of exhibits received so far to date and this list will be updated daily.

Please note that the letters of comment that have been filed with the Board are marked as Exhibit D and are posted on the website as well.

So if any party has a cell phone, I would ask them to turn it off during their proceedings or put it on vibrate.

And I would now ask Ms. Bentivegna, counsel for the Board, to proceed to register the parties.

MS. BENTIVEGNA: Thank you, Mr. Chair.

The YEC. Who's representing YEC?

MR. LANDRY: Thank you, Mr. Chairman. My name is John Landry, and I'm here to represent Yukon Energy.

MS. BENTIVEGNA: For YECL? No one speaking up. We'll move on.

For UCG?

MR. JANIGAN: Thank you. My name is Michael Janigan. I'm appearing on behalf of UCG.

MS. BENTIVEGNA: For YCS/LE.

MR. AUSTIN: Good morning, Mr. Chair. My name is David Austin representing or acting on behalf of the Yukon Conservation Society and Leading Edge Consulting. And this is my first appearance before the Yukon Utilities Board, and thank you very much for allowing me to be here.

THE CHAIR: We'll be gentle with you.

MR. AUSTIN: I can't say I'll return the compliment.

THE CHAIR: Thank you.

MS. BENTIVEGNA: Mr. Donald Roberts.

MR. ROBERTS: Donald Roberts. Welcome Bruce. I used to work with Bruce.

I'm here as a layman and I'm hoping to learn a

lot and hoping to impart some of my concerns. Thank you.

THE CHAIR: Thank you.

MS. BENTIVEGNA: Is there any other person that wishes to register at this time? Seeing none, Mr. Chair, those are the parties.

THE CHAIR: Proceed with swearing in the -- oh, sorry, I'll turn it over to Mr. Landry.

MR. LANDRY: Thank you, Mr. Chair. We will be presenting one panel of witnesses which you can see on your far right, and the witnesses will be, who I'm sure you're familiar with, David Morrison who is the president and CEO of Yukon Energy, Cameron Osler who is the chair and CEO of Energroup and a long-time consultant with Yukon Energy and has appeared before this Board many times. And on your far right is Mr. Hector Campbell who is a longtime employee of Yukon Energy and is the director of resource planning.

So that will be the panel and only panel of witnesses that Yukon Energy will be presenting.

And I should say that we also filed last night a copy of our -- the opening for Yukon Energy, opening statement, and that has been distributed to all parties. And there's extra copies if people in the room require a copy of the opening statement.

And so we'll go right into the opening statement after the witnesses are sworn. So it's probably a

good time to swear the witnesses at this time.

THE CHAIR: Thank you.

H. CAMPBELL, C. OSLER, D. MORRISON (For Yukon Energy Corporation), sworn

MR. LANDRY: So, Mr. Chair, Mr. Morrison I believe will lead on the opening statement.

THE CHAIR: Please proceed, Mr. Morrison.

A. MR. MORRISON: Thank you, Mr. Chair.

Mr. Chair and members of the Panel, Yukon Energy welcomes the opportunity today to be in front of the Yukon Utilities Board for your review of the Whitehorse Diesel-Natural Gas Conversion Project application that Yukon Energy has filed with the Minister of Justice for energy certificates under Part 3 of the *Public Utilities Act*.

The project will modernize Yukon Energy's Whitehorse thermal generating station and provide reliable and flexible thermal generation on the Yukon grid with the conversion of diesel generation units scheduled for retirement to cheaper and cleaner burning natural gas-fired generating units supplied by liquefied natural gas delivered by truck from British Columbia or Alberta.

The project scope involves replacing two end-of-life diesel generating units, referred to as WD1 and WD2, scheduled for retirement in 2014 and 2015 in the

existing Whitehorse diesel plant, with three new modular natural gas-fired generating units to be located adjacent to the Whitehorse plant site - overall, replacing 9.1 megawatt of end-of-life diesel generation with 13.1 new gas generation; and the installation of LNG truck offloading, storage, vaporization, and related infrastructure.

To accommodate the new facilities required for the project, Yukon Energy will acquire approximately .9 hectares of public utility zoned Yukon government lands and create access and utility crossings at various locations along .6 hectares of privately held railway right-of-way, adjacent to the south of the existing Whitehorse thermal generating station site.

The first two natural gas-fired units (8.8 megawatt in total capacity) are to be in service before the end of 2014, to provide capacity and fuel cost savings during the winter of 2014/2015.

The third unit, the 4.4 megawatt unit, is planned to be installed, as required, to meet grid capacity planning requirements, likely by late 2016. The estimated capital cost for the project overall is 40.9 million, with $36.5 million for the initial phase to be completed by the end of 2014 and the balance of 4.4 million when the third natural gas-fired units is installed.

The primary need for the project is related to

capacity. That is, it is needed to meet the Yukon Energy's capacity requirements for the Yukon grid. However, there is also an opportunity to utilize cheaper natural gas to replace incremental winter diesel requirements and benefit both the environment and ratepayers.

The purpose of the current YUB review and hearing is to provide the Minister with the Board's report and recommendations on the public need for the project under various reasonable electric load forecasts and the effect of the project on rates of customers;

the capability of existing and currently committed generation and transmission facilities to provide reliable electric power generation to meet the forecast load requirements and YEC capacity planning criteria;

alternatives to the project given reasonable load assumptions;

the risks facing the project and the potential impacts on rates for customers and whether it is prudent to build the project at this time.

The application and responses to approximately 580 information requests from the Board and interveners address these matters and demonstrate the clear need for the project at this time, the robustness of the project economics given the number of sensitivity tests and the material savings expected to ratepayers over the project's economic

life.

The 2006 resource plan indicated that as of 2006 Yukon Energy faced significant pending capacity shortfalls on the WAF grid related to the adoption of the new capacity planning criteria, as well as the planned retirement of WD1, 2, and 3 in combination with ongoing load growth. Yukon Energy initiated a series of activities to address these potential shortfalls, including recommissioning of the Mirrlees diesel FD1 at Faro and planning for the staged refurbishment of up to three Mirrlees units at Whitehorse, totalling 14 megawatts, over the period 2012, commencing with refurbishment of WD3 in 2007.

The 2006 resource plan also provided the foundation for Yukon Energy to pursue over the past decade major renewable grid enhancement projects. By the end of 2011, completion of the Carmacks-Stewart Transmission Project connected the WAF and Mayo Dawson grids and completion of Mayo B and the Aishihik third turbine expanded Yukon Energy's hydro generating capability with ongoing reductions in diesel generation.

In 2011 Yukon Energy continued its resource planning process. Discussions with stakeholders and public about energy choices, including the need for backup thermal capacity for Yukon's isolated hydro-based system, continued as part of a three-day Energy Charrette. One of the supply

options examined at the Charrette was LNG.

The Charrette planning process led to the definition and adoption of four criteria for evaluation and decision-making that were used to assess supply options in the 2011 resource plan: reliability, affordability, flexibility, and environmental responsibility.

Following the Charrette, Yukon Energy continued to host technology-specific workshops, including a public workshop in January 2012 on the potential use of LNG for electrical generation. Subsequent to this, the overview to the 2011 resource plan was made public in July 2012 during YEC's 2012/2013 GRA review by this Board.

Building on the Charrette process, the 2011 resource plan reviewed a wide range of near-term and longer-term supply options against the number of grid load scenarios and identified the critical need for resource options to be both flexible and reliable in the near term in order to address changing load and supply conditions on the isolated Yukon grid.

Today, notwithstanding increased hydro generation capabilities and the absence of new mine loads being connected to the grid, ongoing load growth on the Yukon grid has depleted the surplus hydro available since the 1998 Faro mine shutdown.

Based on long-term average hydro generation

and current loads, and notwithstanding the extensive investments made in renewable energy projects over the last ten years, diesel generation has once again become the default option to meet current energy and capacity requirements on the Yukon grid until long-term loads are sufficient to support other economic renewable generation. Diesel generation costs are also once again included in rates based on long-term average hydro generation.

The need for the project is driven by a forecast grid capacity shortfall of 7 megawatts by the start of 2015, 10.9 megawatts by the start of 2017, and 17 megawatts by the start of 2019.

These forecast grid capacity shortfalls reflect forecast non-industrial peak winter load, reserve capacity needed to meet N minus 1 risk, the loss of the Aishihik line, and the firm winter capacity capability of existing and currently committed generation and transmission. The fact that WD1 and WD2 are end-of-life in 2014/15 removes 8 megawatts of derated capacity at Whitehorse and drives the need for 7 megawatts of new capacity by the start of 2015.

The project's initial 8.8 megawatts of new gas-fired generation to be in service by the start of 2015 will meet this capacity shortfall need. The third 4.375 megawatt gas-fired unit is currently expected to be in service by the start of 2017 to meet the capacity shortfall

need forecast at that time.

This need also results in an opportunity to modernize the existing Whitehorse diesel plant with gas-fired generating units that are cleaner burning and cheaper to run than diesel units - benefitting the Yukon environment and ratepayers.

WD1 and WD2 have been in service for 46 years and are at end of life.

Plans for the retirement of these units have been in place as far back as the 1992 resource plan here. In the past retirement could be deferred due to the material surplus hydro generation available on the WAF grid after the closer closure of the Faro mine in 1998, the recommissioning of FD1 and refurbishment of WD3, and the expectation that WD1 and WD2 units would not yet be needed to meet grid capacity.

Retirement of these Whitehorse diesel units can no longer be delayed and maintaining these units in service beyond the end of 2014 in their current condition is not an option.

In planning for the future it is also relevant to recognize that the remaining five diesel units at the Whitehorse plant are all planned to be retired within the next 13 years. And that ongoing modernization of this key facility at Yukon's largest load centre will be needed over this period.

We have found no reasonable feasible renewable option alternatives to the project that have been identified.

Potential near term hydro enhancement projects such as Mayo Lake and Marsh Lake Storage are estimated respectively to supply 4 and 6 gigawatt hours, based on long-term average, of incremental energy supply to the grid. However, these hydro enhancement options will not meet the identified need today or in the future for new, flexible, and reliable capacity.

Greenfield renewal options, such as wind or hydro, are being considered for future development when higher and longer term grid energy loads can justify such developments. However, such options do not provide reliable, flexible capacity to meet the grid's backup capacity requirements.

WD1 and WD2 are at end of life, as I've already mentioned. They are 46 years old and, without major refurbishment, can no longer be relied upon for backup capacity.

In 2006 Yukon Energy considered refurbishment for the end-of-life diesel generation as a potential cost effective option to ensure continued reliable capacity on the grid. However, this option was only considered possible after receiving guarantees of continued support for the refurbished engines from the manufacturer (MAN) including the

continued availability of spare parts and technical support. At that time, YEC elected to focus on FD1 and WD3 in order to gain experience, and deferred expenditures on the other Mirrlees units until there was a confirmed need to meet a forecast capacity planning shortfall.

Unfortunately, YEC experience with the refurbishment of WD and FD1 has demonstrated that the promised support from MAN was, in fact, not available and aftermarket part suppliers and technical support is terribly unreliable. Long delays and significant problems in ordering parts, material issues with quality control and lack of component technical support means that refurbishment of these 46-year-old engines is not feasible and they must now be replaced.

In short, refurbishment of the WD1 and WD2 units is not an acceptable option today to meet the current capacity shortfall.

New higher efficiency diesel generation installed in the WD1 and WD2 service bays at the Whitehorse diesel plant was determined to be a feasible and cost-effective option to meet the current capacity shortfall on a grid with forecast long-term average default diesel generation requirements today. This alternative was, therefore, used in the application to assess the prudence and cost-effectiveness of this project.

Overall, although the application shows that replacing the old diesel units with new and more efficient diesel units would have an incrementally lower capital cost compared to the gas-fired units, the opportunity to meet the Yukon grid's capacity shortfall with new, cleaner burning cheaper operating gas-fired units mean that the project is, by far, superior and most cost-effective option.

In addition to the capacity needed on the Yukon grid, a second prerequisite for the project is a secure supply of LNG that can be trucked to Whitehorse from BC or Alberta.

At the time of Yukon Energy's January 2012 LNG workshop, the only identified source for near-term LNG supply to Yukon were LNG export developments planned at Kitimat, an announced Shell Canada LNG plant planned in Calgary, and a potential future LNG facility development in Fort Nelson.

Working with Western Copper & Gold, Yukon Energy in early 2012 carried out a request for interest proposal process which led to a proposal from Shell Canada to supply YEC with LNG from its Jumping Pound LNG plant to be opened in Calgary in 2014. YEC subsequently worked with Shell Canada to finalize by early 2013 the energy supply agreement outlined in the project application submitted to the Minister in December 2013.

During 2013, Yukon Energy was informed of

delays in planned construction of the Shell Jumping Pound facility construction from summer 2013 to late fall, and as a result, contingency planning for a delay in the Shell plant in Calgary beyond Quarter 4, 2014 has been underway since the fall of 2013. Although formal termination of the contract has not yet occurred, on February 19th, Shell senior officials informed YEC Energy that notwithstanding construction on the site had been commenced and material equipment purchases had been made, Shell had decided not to proceed with Jumping Pound at this time.

Although Yukon Energy reviewed its contingency plans in the IR responses filed at the end of February, it continued to wait to update the Board and the parties on the Shell situation until after it had fully absorbed the Shell decision and had in place a committed alternative LNG supply.

March 27th, 2014 update explains Shell's decision not to proceed with its Jumping Pound LNG plant, and set out the following revised plans by Yukon Energy to secure LNG supply for the project.

LNG supply from FortisBC: Yukon Energy will now secure LNG supply from FortisBC's LNG facility at Tilbury, near Delta B.C. until such time as lower cost source of LNG is available.

Yukon has met with FortisBC and has confirmed that ample LNG supply is available to meet project

requirements from the operating Fortis facility at Tilbury, including supply from existing facilities during 2015 and supply from the next major expansion that has BC Government regulatory approval and is planned to start operation in 2016.

The rate for supply from Fortis will be based on the regulatory cost-based price under the BCUC approved Rate Schedule 46 (approved in accordance with a direction to the BCUC from the BC Government as set out in OIC 557-13).

Yukon Energy is also coordinating plans with NT Energy, who is currently securing LNG from Fortis at Tilbury for their use at Inuvik, to utilize NT Energy's Tridem units until such time as A-Train units are permitted. Yukon Energy and NT Energy are also exploring how joint cost savings with A-Train units can be secured once they are permitted.

Yukon Energy Corporation is working with NT Energy on other potential near term lower cost LNG supply options that could be located closer to Yukon, including potential options with AltaGas and Ferus as noted in the March 27th update.

Overall, the interest in near term LNG domestic supply development has grown considerably in the last 12 months in both Alberta and B.C., including potential facilities in Edmonton, Grande Prairie, Dawson Creek and Fort

Nelson.

In short, Yukon Energy has access to a secure LNG supply at a price level that is not materially different than the Shell agreement.

The economics of the project focus on three key comparisons with the only other flexible alternative new diesel: Capital costs; fuel costs per kilowatt hour; and volume of diesel displaced by the project.

There is no material difference in terms of equipment costs, new gas, or new diesel generation units. The primary capital cost difference between the new alternatives is the requirement to establish new facilities needed for LNG truck unload, storage, and vaporization.

As reviewed in the application and responses to IRs, important elements of these LNG facilities will have the capability to support up to 30 megawatts of gas-related future generation capacity at the Whitehorse thermal generation plant.

The capital cost estimates included in Table 4.3 of the March update filing show $36.5 million for the project to the end of 2014, and $5.5 million for the third engine in 2016, including an added contingency of $1.1 million, compared with $32.7 million for the new diesel alternatives assumed to be completed in two stages over 2014 and 2015.

The updated capital costs estimate reflects Yukon Energy's response to YUB-YEC-1-1(d), which showed an increase from the $34.4 million May 2013 estimate originally included in the application to $36.5 million.

The updated estimates reflect the outcomes of tenders and RFPs carried out for engineering, project management, LNG plant and equipment, and transformer equipment; include $1.0 million in contingency for construction contracts not yet awarded.

On March 19, 2014, the YESAB draft screening report was issued recommending to the Government of Yukon, the decision body in this case, that the project be allowed to proceed without a review -- proceed without review, subject to the eight terms and conditions recommended in the report.

The executive committee noted that the relatively few recommendations in its report are indicative of the comprehensiveness of Yukon Energy's commitments. Except for the recommendation to install underground power distribution lines, which YEC will discuss and seek to have revised, Yukon Energy's current plans accommodate all of the YESAB DSR recommended terms without any discernible adjustment to design or cost.

Public comment on the draft screening report is expected to close by April 22nd and, on this basis, a

final YESAB recommendation is still expected by about the end of April.

Release of a positive YESAB draft screening report means that Yukon Energy's mid-May estimated construction schedule is on track and, subject to formal completion of the YESAB process and decision document and permit processes, effectively mitigates one of the remaining risks to capital costs, i.e, cost impacts from the delays in construction. Yukon Energy continues to work cooperatively with YESAB and the relevant Yukon government officials to ensure that the mid-May scheduled construction can be met.

Further, in order to protect overall project construction schedule, tenders for the civil construction contracts have also now been issued.

The updated filing March 27th shows estimated fuel cost savings in 2015 at 12.3 cents per kilowatt hours of generation for gas versus new diesel and 16.8 cents per kilowatt hour for gas versus the existing or older diesel on the grid.

Focusing on the updated fuel cost savings per kilowatt hour for 2015, the following are noted:

Updated diesel fuel costs reflect average diesel price to YEC at Whitehorse for the latest six months as reviewed in IR responses.

Updated LNG costs reflect updated haul costs.

The assumed AECO gas price of $4.50 per million Btu's is retained. It is still considered a conservative assumption based on the average of AECO prices over the last six months, which averaged $3.70 per million Btu's as reviewed in IR responses.

The updated fuel cost savings per kilowatt hour has not been materially impacted by the change in LNG supply to the existing FortisBC plant at Tilbury.

The material cost savings for gas versus diesel is forecast to be sustained in North America over at least the next two to three decades. Aside from US Energy Information Administration long-term world crude oil and US natural gas price forecasts reviewed in the application and in IRs, active ongoing consideration of various LNG export opportunities from British Columbia to Asia, as well as development of new LNG production facilities in Western Canada to supply domestic markets, reflect key stakeholders, including the B.C. government, expectations that the major gap between North American natural gas prices and world crude oil prices will likely be sustained for the next 20 years or more into the future.

Table 4.3 in the application, as updated March 27th, illustrates that additional capital costs of 9.3 million for the project, compared with the new diesel alternative, including an added 1.1 million cost contingency

for the third gas engine, are forecast to be fully paid off within the first four years of the project operation through annual fuel cost savings.

Given that Yukon electricity rates are based on long-term average hydro generation rates, projected ratepayer fuel cost savings from the project over the four initial years approximate $11.9 million using the conservative base case load forecast with no Alexco load.

These fuel cost savings are well in excess of the projected capital cost charges of approximately $2.7 million for the project compared to new diesel, resulting in overall ratepayer savings exceeding $9 million over that time period, including 1 million in 2015 alone.

Projected fuel cost savings of 11.9 million in the first four years are also in excess of the 9.3 million additional capital cost assumed for the project compared to the new diesel alternative, which means that the project's added capital costs are projected to be fully covered during these initial four operating years.

The application demonstrates that the project's economics and ratepayer cost savings are very robust, confirming that ratepayer cost savings will be sustained under a wide range of possible scenarios, including material capital cost increases, reductions in fuel cost savings, and the changes in diesel generation forecast.

Thank you, Mr. Chairman. That's my opening remarks.

THE CHAIR: Thank you, Mr. Morrison.

MR. LANDRY: Thank you, Mr. Chairman. Just for the record, the opening statement has been marked already as B-14, Exhibit B-14.

THE CHAIR: So marked. Thank you. Proceed.

MR. LANDRY: So, Mr. Chairman, the panel is now available for cross-examination.

THE CHAIR: So looking at my list here, I believe UCG, Mr. Janigan is up for cross-examination. You can proceed whenever you're ready.

MR. JANIGAN: Thank you, Mr. Chair. I have a compendium of cross-examination material that is currently being printed and should be available to me sometime after 10:00, if I retrieve them from Staples. But what I'm going to do is try and work around that compendium in relation to my cross so that I cover areas that I don't need that compendium. It may mean that I may have to go back briefly with a few questions and so my cross may be a bit choppy. But I think I can probably go to the break. And if I can get an extended break, to make sure that I get back from Staples in time with my box of materials, I would appreciate it.

THE CHAIR: We would make sure we let you

get back. Yes, and that's fine. That process is fine. And if you need to take a break a little bit earlier, you can do that as well.

MR. JANIGAN: Thank you very much.

MR. JANIGAN CROSS-EXAMINES THE PANEL:

Q. So, panel, as you've heard, I may actually welcome long answers up until the break from the panel, for a change.

My first area of questioning deals with the terms of reference in relation to the task before the Board. And I believe that this is set out -- the terms of reference are in the exhibit list A-2, I believe.

If you have them, it indicates that the YUB shall report on and make recommendations about the necessity for the Whitehorse Diesel-Natural Gas Conversion Project and its timing and design with particular regard to item number C, the risks facing the Whitehorse Diesel-Natural Gas Conversion Project and their potential impacts on rates for customers.

Now, in a number of places in evidence I believe you put in the cost-benefit analysis, and I just want to confirm that I've got them all. First is the updated Table 4-3 -- initially in the application, updated with your updated March 27th -- and there's also been a what-if variance analysis that has been provided in response to interrogatory YCS/LE-YEC-1-42. You might want to turn that

up.

Next is YUB-YEC-1-12 and YUB-YEC-1-13. I just want to make sure that I've got the -- all of the various analyses that were prepared by YEC in relation to cost benefit.

A. MR. OSLER: The updated numbers are provided in the Exhibit E-13 update that you referred to at the beginning Table 4-3, page A-5. That would be the most current set of numbers.

A lot of the numbers in that table were provided previously in response to YUB 13, which you mentioned. In 13(a) in particular, there are some tables there. It's really only updated from YUB 13 to take into account the acquisition of the gas from Fortis rather than Shell.

There are a variety of different questions we were asked to look at variations on this table. You've mentioned YCS 42. There probably are a number of other ones. You know, we were asked by the Board and YCS, which will come up during the course of the discussions.

The information on the diesel alternative is found in various places. YECL 6 is a table under diesel costs, and there are other answers that work from that.

So, I mean, I don't think I'd like to summarize and say we've covered everything, but the most

important up-to-date table is the one you referenced first, is the Table 4.3 in the updated Exhibit E-13.

Q. Okay. Now, the updated table of 4.3, does that consider all components of YEC's revenue requirement in terms of effect? In other words, you have the list of the effect on depreciation return. Are there other impacts, financial impacts, apart from depreciation of return on YEC's revenue requirement associated with this project?

A. MR. OSLER: This analysis focuses on the elements of YEC's revenue requirement where you would expect the project to have any material effect. That would include the impacts from capital costs related to the project, which affect depreciation and return on rate base. And they also would relate to the fuel cost requirements associated with this project compared to the alternative new diesel.

There were questions asked about non-fuel O&M costs, and the answers in the IRs say that we do not expect there to be any material difference between the non-fuel O&M costs and the new diesel alternative project.

Beyond that, sir, we don't believe there's any other pathway to effect on the revenue requirements associated with this project.

Q. What's your definition of material in terms of quantum?

A. MR. OSLER: Ability to estimate it all usefully for the purposes of this investigation.

Q. I don't quite know what that means.
A. MR. OSLER: There always can be some effect. For example, there might be differences on non-fuel O&M costs that will be averred over time, but we have no ability to estimate them in the context of this application. And if we look into it retrospectively, we would not expect it to have any effect on the overall decision-making assessment of the prudence of this project or the desirability of opportunity to its alternatives.
Q. And I take it we would look to Table 4.3 if we were to try to forecast overall revenue requirement impacts over the impacts on rates that might result from the proposed project. Would that be correct?
A. MR. OSLER: Yes. The table framework that you have in Table 4-3 allows you to see the nature and the magnitude expected of the impacts of this project relative to the new diesel alternative.
The table by itself does not show you the overall effect of the new alternative of the new project or its alternative compared to the world going forward without doing anything, but you can use this table to come up with that type of analysis if you're interested.
For example, the table shows you the forecast long term average diesel at 17 gigawatt hours in 2015, 22.9 in 2016, etcetera. The table says that the average cost of

meeting that energy requirement for diesel using the existing grid energy from diesel would be approximately 30.8 cents per kilowatt hour.

So if you wanted to have an assessment of what the cost of meeting that requirement using existing diesel without any new capital expenditure, you can simply multiply 30.8 cents by those numbers and you will see that it comes up with 5.2 million in the first year, etcetera. That would give you an indication of what the system would incur in terms of costs without any new capital expenditure at all.

If you contrast this project with that stream, you will see that it's basically the same cost in the first year and gets to be a little bit less than that stream each year thereafter.

Q. Now, including this YUB review and the review by the YESAB, how much money has been spent or committed to be spent on this proposed project to date?

A. MR. OSLER: We'll get the number, but it was in answer to YUB 2 that gives the assessment or response to the Board's question of costs that have been sunk to date, is the expression, and it goes through -- it goes through the costs incurred to January 2014. It shows an estimate broken down of 12.5 million. It shows an estimate of costs to be incurred from February to April 2014 broken down totalling 4.5 million. And it includes a final column of costs that

would be incurred if the project had to be cancelled of, say, 2.8 million.

The text -- so all of that comes in just under $20 million. The text explains that these are costs that do not reflect the extent to which some of these items, particularly the 10.9 million of the 19.8 million is all related to the LNG engines acquisition, and the text explains that some of that cost would likely be recovered -- the material portion would be recovered but we have no basis to know what the estimated amount would be.

To quote it, YEC would expect to recover a major portion of the 10.9 million spent on the engines, but it is not feasible to estimate the net receipts or duration of a cancellation process.

In that package, the planning costs incurred to date are shown approximately 2.3 million. That would be a lot more than just the regulatory process. That would be a design -- I think there is an IR in the package that asks specifically about the costs respecting the two regulatory processes. We can find that if you're interested.

Q. That would be helpful for purposes of -- if possible --

A. MR. OSLER: We'll track it down rather than trying to grab it right at this moment.

Q. If I can understand the process for -- in the event the project goes ahead, the process for the collection of those

costs and rates. I take it that much of these costs will be capitalized and put in rate base at some point in time of the project.

A. MR. OSLER: The capital costs would be capitalized and, subject to the Board's review as to prudence, put into rate base.

Q. And that will include a portion of the planning costs that will be incurred?

A. MR. OSLER: It would include all of the costs incurred, including the planning costs.

Q. So it would include all the planning costs?

A. MR. OSLER: It should subject to Board's review and approval.

Q. When is that closed to rate base? When the -- when the project is being used?

A. MR. OSLER: Well, the two requirements for bringing a capital project into rates, one of them is that it's used. It's actually brought into service and useful. The second one is you have to have gone through a rate review process by this Board to change rates to reflect these costs. So two steps, both are required --

Q. Okay. So those costs won't be closed to rate base until those two steps occur?

A. MR. OSLER: Well, I'd be very careful. We can't go into rates until the Board changes the rates. So

you can be comfortable with that. I think the accounting department would put them into the costs of the company and charge them against their own revenues as soon as it becomes operational. So they don't get rates. They will still have to show on the books that they're incurring those costs. Until they go into service, the costs are treated as work in progress and they do not affect the income of the company.

Q. And they're backed out of one and put into the other. Is that effectively what happens?

A. MR. OSLER: Could you say that again?

Q. Are they backed out of the one and put in the other. Is that effectively what happens?

A. MR. OSLER: You move it from work in progress into a cost that is charged against income, yes.

Q. Do you operate on the half-year rule in relation to capital costs and depreciation?

A. MR. OSLER: Do you mean by that question, sir, do we take an average rate base beginning and end of the year?

Q. Well, that was once one system; the other system being that one is put into rate base at any point in time in the year and it's credited with six-month depreciation cost of capital --

A. MR. OSLER: We'll check with our accounting people, but subject to check, we'll say yes.

Q. Okay. And I believe I've seen some discourse in the interrogatories concerning the possibility of necessity for a deferral account in relation to this.

As I understand YEC's position is that they're capable of tracking the costs associated with this project in a way in which would assure a completeness in relation to ensuring that only the costs of this project go into rate base and go into rate base after the two steps have been taken. Am I correct on that?

A. MR. MORRISON: Mr. Chair, our normal practice with all capital projects is completely segregated. The costs are tracked individually. We're operating this project the same as we have all others. We have no -- they have their own code. All charges to the project are only those charges to the project. It's a work-in-progress account at the moment. At some point we will move it into a rate base, but we -- that's how we normally do our accounting of a capital project.

Q. And until it's moved into rate base, how is it financed?

A. MR. MORRISON: It's financed from internal sources as required.

Q. And those internal sources are?

A. MR. MORRISON: Well, either we'll -- we'll either use existing cash flow. We may, in fact, look at our total capital requirements from one year to the next and

whatever borrowings we need to do, they will provide cash related to the project.

Q. And the cost of those borrowings will be applied to the project.

A. MR. MORRISON: As with all other capital works, the cost of borrowing money to finance works done by the corporation is a cost that comes before this tribunal when we have rate hearings, and those costs are either allowed or denied.

A. MR. OSLER: In essence, sir, all of the costs of the company requires for financing capital costs get to be financed and the overall average of all those financing costs gets charged against the company. So this project is just one of many elements that contribute to the capital costs and the financing requirements.

Q. But at some level it's segregated out for attribution purposes.

A. MR. MORRISON: Absolutely, yes.

Q. When did the YEC's Board of directors give approval to the proposed LNG Project?

A. MR. MORRISON: My best recollection, Mr. Chair, is May 2013.

Q. Do you know whether the decision by the Board of directors was unanimous?

A. MR. MORRISON: Well, I'm going to say it this

way: I don't recall anybody dissenting to the decision.

Q. Is that your recollection, or is it --

A. MR. MORRISON: Well, I was in the room. I didn't hear any dissent.

Q. Okay. Your memory is good on that with respect to that meeting?

A. MR. MORRISON: Yeah.

Q. Okay.

A. That doesn't mean to say it's always good.

Q. All right. Is there any difference in the project components and costs between the project that YEC's Board of directors included and the project components and costs currently before the YUB?

A. MR. MORRISON: Mr. Chair, we have a very iterative process with our Board. We get a lot of information and they get major changes. Any changes in a budget of a project are provided to the Board for -- depending on levels, for either approval or review. The budget that's before this Board has been approved by the Board of directors.

Q. So that includes the update of March 27th?

A. MR. MORRISON: That's correct.

Q. Okay. I'm going to skip over to another area, and once again, first of all, look at the terms of reference again in the Exhibit A-2. And according to the terms of reference in

the minister's referral to the YUB dated December 20th, 2013:

> "The YUB shall report on and make recommendations about the necessity for the Whitehorse Diesel-Natural Gas Conversion Project and its timing and design, with particular regard to:"

In this case item number d.:

> "What, if any, alternatives to the Whitehorse Diesel-Natural Gas Conversion Project might be advisable given reasonable load assumptions and risk assessments."

Now, I want to take you through the alternatives that YEC considered to the proposed project. And that first of all the first one would have been the status quo or do-nothing alternative. That was considered?

A. MR. MORRISON: Yes.

Q. Right?

A. MR. MORRISON: Considered.

Q. Yes. The next one was near-term hydro enhancement projects. Was that considered?

A. MR. MORRISON: Mr. Chair, for the -- I want to separate a couple of things here, and I think it's an important juncture. We consider and we do planning -- I think as most people in the room know, we have done an

extensive amount of planning on a lot of different alternatives over the past several years.

One of them, as of January 1st, is the near-term hydro enhancement project. And we certainly continue to work on those things, have worked on those projects. They're good projects. But they are not projects relevant for consideration in this situation. The primary function of this project is capacity. These hydro enhancement projects have not provided capacity.

Q. So you considered it and rejected it?

A. MR. MORRISON: We considered it and rejected it.

Q. Okay.

A. MR. MORRISON: Let me say -- I want to be clear. We did not consider those for this project, for this requirement. They're part of another list. I'm just parsing words, but I think Mr. Janigan's wanting something very specific. We did not consider it.

Q. Okay. Life extension of the Mirrlees WD1 and WD2 units?

A. MR. MORRISON: Yes, we did.

Q. Replacement of the Mirrlees units with new high efficiency diesel engines?

A. MR. MORRISON: Yes, we did.

Q. Okay. Now, I think you were touching upon the answer to this question in the last question, but I'll ask it directly.

Why didn't YEC look at other renewable generation alternatives?

A. MR. MORRISON: Well, I'll start, and Mr. Osler or Mr. Campbell may want to assist. As I said, the primary purpose of this initiative was to figure out a solution for the replacement of diesel units that had to be replaced and form the basis and the foundation of our capacity requirements fr our backup system, if you want to talk about that. And we all know that we're an isolated grid, no link to anywhere else. We all know that if we lose the grid, which has become our risk point of concern, that we need to have a backup system in place that enables us to provide power to Yukoners for an extended period of time; not just in the winter but on a year-round basis.

And we have been in front of this Board on numerous occasions. We have established a capacity planning criteria along with this Board. We looked at that, and we look at that on a continuing basis. When we looked at the state of the engines, our inability to get the parts, we knew we had to do something.

So we sat down and, as we do with everything else, we consider all of the options because we realize -- first of all because we want to know which is the best outcome. We also know that we have to be able to prove those options that we go forward with at some point in a regulatory

process; going into rates or in a hearing such as this.

So renewables are in general high capital cost, low operating cost. Having renewables and large renewables sitting in the system with high capital costs and performing at intermittent times during the year is not an economic proposition that works.

What we need in a backup system is a system that is flexible and reliable. We need a system that's dispatchable, that we can turn a switch when we need it. When we lose alternative A over here, the hydro, we can turn a switch and this power comes on. It may come on for very short periods of time, but it's still important that it comes on.

In addition to that the capacity issue. We also have to cover the risks of drought or long-term drought. And, again, high capital cost renewables sitting on the system don't give us that opportunity at an affordable rate for ratepayers. Waiting for a drought is something that diesel or thermal-based generation can do because they have low costs and you save the operating costs by not running. You don't save any costs by not running hydro. You're virtually down to very small O&M species. What you're faced with is the large capital costs that have to be absorbed by ratepayers.

So those are the reasons, primarily -- and I

don't know if Mr. Osler had something to add to that, but those are the primary reasons that renewables don't fit in this scenario.

A. MR. OSLER: I think the key points are all in the context of hydro and wind capital intensive renewables have all the features Mr. Morrison just went through in contrast to a thermal alternative, where you spend, relatively speaking, in terms of capital a lot less and you only incur the operating costs when you absolutely need to run a generating unit.

Yukon Energy in its last resource plan, 2011 resource plan, went through exhaustively the various options for generation. So it's not that they don't have the information on the various renewables. And there have been IRs in this hearing where we've been asked questions about that, and no doubt we'll refer to them.

CW10 give us a general review of the issues -- and there are specific ones on wind and other things, but the general point for what the need is here is to find the most -- to find a reliable, flexible generating option that will put in place the capacity needed to keep the grid reliable and not incur any more costs than needed, except when you absolutely have to do the generation because of drought, because of emergency, or because you don't have other generation available.

Q. Okay. If I can try to organize those two answers, at least so I can understand them, the big problem with renewable generation alternatives, as I understand it, is that for -- effectively for backup supply they are not an economic alternative?

A. MR. MORRISON: That's correct. And they also -- it depends on what renewable it is. So, you know, one of the issues that I mentioned earlier is it also has to be something that is dispatchable. What I mean by that is that it's available when needed in response to our operators turning the units on. Depending on what the renewable resource is, that may not be the case.

Q. So that's what I wanted to get at. The dispatchability is different between renewables and thermal?

A. MR. MORRISON: That's correct.

A. MR. OSLER: Just to be clear, there are renewables that can be thermal, such as a biomass generating facility. So we've got to be careful that we're not misstating anything. But in Yukon's context, from the information Yukon Energy's collected, the renewables that are there for future development tend to be capital intensive wind or hydro. It doesn't look as though the biomass alternative would be nearly as feasible.

Q. And wind and hydro are difficult or may have problems with dispatchability that diesel and LNG won't have?

A. MR. MORRISON: Well, that certainly is the case. The location, as well, is also an issue in relation to that. Remembering that within the system the thermal units are geographically located within communities. They don't suffer from having to be responsive to the line itself, to the grid. And if you're losing the grid in a major way, you don't want to be exposed to any renewable situation that has -- that requires that gid to give you access to the power.

So the other benefit is that within communities these diesel or thermal units provide localized response dispatchability and the cheap economics.

Q. And I take it the renewables aren't necessarily situate in these communities. They may be situate elsewhere and depend on the grid for delivery.

A. MR. OSLER: Certainly it's a possibility, yes. When we talk about the N minus 1 test for capacity, we're doing exactly what Mr. Morrison just referred to. We're looking at the possibility of the Aishihik line coming down, and we can't get access to the 37 megawatts of renewable energy at Aishihik. And so we have to design the capacity of the system to withstand that worst-case event, which in fact happened. Some people accused it of happening because we bothered to study it, but -- so it's a perfect example.

In my home province of Manitoba we have the problem of all of the big renewables are up north and they come down through transmission lines there. We are equally concerned about the ability to protect the reliability there. So that's the example.

Whereas you put your thermal generation in your load centres and you move the fuel to it -- and Whitehorse has the largest load centre in Whitehorse -- in the Yukon, and the largest generating unit there is the one we're talking about, the Whitehorse generators.

Q. Did YEC consider enhanced DSM as an alternative?

A. MR. MORRISON: Yes, we have considered DSM efforts. We are awaiting the decision from the YUB on YECL's DSM plan because we're partners with them on that.

The DSM savings, which we certainly feel we can get and hope to get over time, will help some, but they will not replace capacity requirements sufficiently to offset the requirements here.

A. MR. OSLER: But I would say, for the record, the forecasts used in this application in Appendix C incorporate the DSM measures that the companies have proposed to the extent that we can forecast them. So that it's not only been considered; it's reflected in the forecasts.

Q. And what percentage of capacity is being relieved by DSM savings, approximately, does Appendix C show?

A. There's percentages in the -- there's information in the appendix -- I'd have to go through it to remind myself -- but it phases in over the next five years. So there isn't hardly anything yet because the Board's hasn't approved it and it grows to a number by 2018, something like that.

I don't know how specific people are as to capacity versus energy benefits in the actual plan, but in the forecasting, it's been assumed in general that the capacity tends to be reduced to the same extent as the energy just for forecasting purposes. It isn't so specific that it's getting into trying to mirror the program for capacity versus energy which would be in the detailed DSM plan.

Q. I guess I'm confused. In Appendix C, you built in DSM savings.

A. MR. OSLER: Correct.

Q. And the DSM savings are reducing capacity in some fashion. Is it possible to get a percentage of how much they're reducing over a period of years?

A. MR. OSLER: Well, we'll look at it and see if we can give you that type of information based on what's in that appendix.

Q. That would be helpful.

A. MR. OSLER: My recollection is it's the same percentage as applied to the energy which is a generalization, not a refined analysis that you'd get in a

true DSM.

Q. Whatever you can provide me, I would appreciate it. Can I have an undertaking on that?

A. MR. OSLER: Mr. Campbell thinks he can give it to you.

Q. Certainly.

A. MR. CAMPBELL: What I can tell you with respect to the DSM programs, they, in fact, are targeting towards energy conservation, for energy reduction, not specifically targeted to capacity reduction.

The low-hanging fruit for energy conservation programs typically is saving energy which is why that was the focus and target of our DSM programs.

If you look, for example, at the targeted energy reductions after five years, I believe it's in the orders of five gigawatt hours a year, if you apply that to our overall grid generation cost which exceed 400 gigawatt hours a year, you know, we're talking less, you know, maybe a 1 percent reduction; in capacity, probably less. So it is not significant.

So, in short, it will have no significant reduction of capacity.

Q. Did YEC consider bi-fuel conversion kits that allow diesel generators to run on more than one fuel?

A. MR. OSLER: What was the question again?

Q. Did YEC consider bi-fuel conversion kits that allow diesel generators to run on more than one fuel?

A. MR. OSLER: Mr. Campbell can --

A. MR. CAMPBELL: The short answer is yes.

Q. And can you tell me why ultimately that they were rejected?

A. MR. CAMPBELL Sure. A few reasons. When we looked at the bi-fuel kits available, there was two disadvantages to them. One, they were only being applied on small engines. The engines that we have in our Whitehorse diesel plant are large engines. So basically, by the time we looked at them, they were not available in the size of engines that we were looking at.

The second reason is they only allow you to displace a percentage of the diesel fuel so you only get a partial savings on the fuel cost.

A. MR. OSLER: I can just -- a couple of points. One of them is, again, going back to the need here which is capacity. One way or the other, we had to provide new capacity, and the refurbishment of the existing WD1 and WD2, as Mr. Morrison has gone through, is not an option. So there was a fundamental requirement to come up with some new capacity.

Now, in that context, the option of buying a new diesel and then having a kit to modify it would be how

that would unfold. In the case here, that wouldn't be a cost-effective approach. You use these kits to modify old engines, existing engines. And I think that's about the essence of the point here.

It does not mean that Yukon Energy is not seriously looking at kits for modifying some of the remaining existing old engines inside the Whitehorse plant. To enhance the extent to which the LNG facility could be installed would increase the benefit displaced in diesel in future and increase the capability to get the savings we're talking about. But that would be with respect to existing EMDs or a Cat engine inside the facility. And that is a serious option I believe Mr. Campbell is looking at.

A. MR. CAMPBELL: That's correct. We maintained discussions with both EMD and Caterpillar and they have advised us the conversion kits will be available in the future, likely by 2016 or 2017. So again, we think that is a viable option in the future that will allow us to fuel switch to maintain the remaining life in the four diesel engines in the plant that do have the ability to provide reliable generation for up to ten more years.

Q. So I take it, Mr. Osler, your analysis follows in lockstep with the conclusion that WD1 and WD2 units are at the end of their life?

A. MR. OSLER: Yes. And not only end of life,

but there isn't an option that's practical to refurbish them for the reasons Mr. Morrison gave.

Q. Did YEC consider buying secondhand diesel generators which would not require any changes to the warehouse?

A. MR. MORRISON: Mr. Chair, the only secondhand units that would not require us changing a plant -- I think Mr. Janigan is referring to the balance -- or let's talk about it as we refer to the balance of plant. So, in other words, all the auxiliary work in the plant would be the same age as the units that we're talking about.

So buying really old engines, refurbishing really, really old engines is throwing, in my mind, good money after bad. You get a short period of time. We wouldn't get the long life economic value out of them that we're going to get with new engines. We have to find reliability in the product that we buy. The only way to get that truly is looking at the whole problem and doing an assessment from stem to stern.

So we can buy diesel -- we can buy new diesel, but the work that's going to have to be done in the generating station adds to the cost. We can go back with old engines, but the old engines, you know, suffer from the same -- same problems that the Mirrlees suffer. People don't make parts for them. They're hard to get. They break down more.

You know, those Mirrlees engines are really, really difficult to run. They've been difficult to run from day one. We've got a lot of life out of them because we've put a lot of work into them. It's not a consideration that makes sense when we look at the principles of making sure that we've got reliability and flexibility in this backup capacity.

Q. And so there's no market out there for secondhand diesel generators that are of vintage that is different than the ones that you were replacing. I take it that's what you're saying?

A. MR. MORRISON: Well, Mr. Chair, what I'm saying is that different engines -- different engines, less old than the 46-year-old engines that we already have, are still going to require significant balance of plant work, and we don't necessarily get a long-term solution to the problem. We get a short-term solution because these engines will age, have the same issues that we were already trying to deal with. We don't think that that's an option.

Q. Given the attractiveness of the price of liquefied natural gas to diesel, one would think that there might be diesel generators on the market that would be considerably less than the 46-year-old models that you have.

A. MR. MORRISON: I'm not -- I'm not sure -- that a question?

Q. Yes, it is.
A. MR. MORRISON: Well, the gas price is attractive. Whether the engines, as Mr. Osler and Mr. Campbell indicated, the engines that are convertible can run dual fuel, are tiny. We don't need tiny engines, we need larger engines. Whether there are diesels out there that we can continue to run old diesels -- to run diesel in, old diesels, lack efficient output rates, I'm sure there are, but they will require significant cost structure related to balance of plant work. And we don't believe that that's a long-term option. That's a short-term solution.
Q. Did you put together a report in relation to the cost to refurbish the Mirrlees engines and the availability of parts for Mirrlees engines? I'll give you consideration of the issue.
THE CHAIR: Mr. Janigan, while they're thinking of the response, I just wanted to note that it's about 10:36. So I'll leave it to you to decide when you feel is an appropriate time to cut off for the break.
MR. JANIGAN: I'm happen to go at this point in time. We can consider that over the break.
THE CHAIR: We'll recess for about 15 minutes subject to Mr. Janigan getting back from Staples and then resume once he's able to get back and get his material together. Thanks very much.

(ADJOURNMENT)

THE CHAIR: Please be seated.

So, Mr. Janigan, I'll turn it back to you. You don't look any worn from your run to Staples and back.

MR. JANIGAN: Well, thank you very much. I was greatly assisted by an employee of the applicant in going to Staples. I'm eternally grateful for that.

THE CHAIR: Thank you. So proceed, please.

MR. JANIGAN: Thank you. Just before we start, we have a -- what I was retrieving was a book of cross-examination materials, and what -- we want to ensure that we comply with the guidance that you have given to us in relation to the compilation of these materials so that in the -- what we're suggesting is that the book be marked for identification purposes and we go through the individual items that are set out here, nine of them in nature, and if any are such that objections are raised that are sustained by the Board in relation to their staying on the record, that we simply remove them from the book and go forward from there.

THE CHAIR: Okay. Now, my understanding, just having a brief discussion with our counsel, is that what you would do is if you used page 3 to 6, that at the end of your question you would then ask that to be given an exhibit number.

So we would specifically say within this book

pages 3 to 6 become Exhibit No. XXX; is that correct?
MR. JANIGAN: That would be fine.
THE CHAIR: That would be preferable to me, if that's okay with you.
MR. JANIGAN: That would be fine.
THE CHAIR: So, Mr. Landry, would you like to speak to that?
MR. LANDRY: I'm fine with that, Mr. Chairman. There will be a few documents that obviously I'll be objecting to, but I'm fine with that type of procedure to help everybody.
THE CHAIR: And my understanding is that it will either be for the purpose of the record if it hasn't been marked as an exhibit number as according to what we just spoke about, then it would not become part of the overall record.
MR. LANDRY: Part of the evidence.
THE CHAIR: Part of the evidence, yes. Thank you.
So I'll turn that back to Mr. Janigan. Thank you, very much.
MR. LANDRY: Mr. Chairman, I think we have a couple of answers to undertakings that we could put on the record now too, if that would be okay.
THE CHAIR: Yes. Please proceed.

A. MR. OSLER: Okay. First of all I said I'd find an IR that dealt with the costs for the YESAB in this hearing as estimated in the planning costs. And, Mr. Janigan, you can find that in response to YCS 11, sections F and G.

Secondly, I undertook to review the DSM and how it was reflected in our forecast in Appendix C. On page C-1, under (a)(i), second bullet, there is a description of assumptions used for DSM. It included the forecasts and the source base for that.

Essentially, the forecast assumed 32 percent of the annual load growth would become reduced because of DSM, but that would only become fully effective starting 2017. And it describes the process for the assumptions for phasing that in up to that time.

On page C-3, there's a Table C-1, which shows you the non-industrial DSM that was assumed in the final column for each year. And if you added that back into the non-industrial load in the first column, you'd have the picture before the DSM versus the picture that you see in this table after DSM.

And those numbers show that there is no DSM assumed until beginning in 2015. And it doesn't really become fully effective, as I just said, until 2017.

This table is an energy forecast table rather

than a capacity forecast table. All I can tell you is that the capacity forecasts that are provided subsequently in Table C-4 effectively reduce the forecast capacity requirement proportionately as the energy is reduced by DSM; which means that it's a very simplifying assumption that was adopted here, which Mr. Campbell has testified that the actual program is much more focused on reducing energy in terms of DSM impacts and capacity.

So to that extent these forecasts perhaps overstate the impact of DSM on capacity, and it wouldn't be material until 2017 and thereafter. And I have no basis today to, you know, advise you as to how to amend that. So that's the follow-up on that matter.

And the final one we were dealing with when we adjourned was the question of reports and evidence on refurbishment of Mirrlees and balance of plant work, and we've referred to YUB 13. It was discussed under (a) and (b), but it's also referred to in (c), and I'll have Mr. Campbell elaborate on what we have on the record on that matter.

A. MR. CAMPBELL: Thank you, Cam.

What I can state is that in fact the cost estimates that the company has generated for the refurbishment of the Mirrlees has risen from a half a million dollars a megawatt to three-quarters of a million dollars a

megawatt based on the experience gained in our first two rebuilds on WD3 and FD1. And that is now approximately half the cost of a new replacement diesel.

Q. I'm sorry. Could you just repeat that, the first part of that -- the first sentence that you gave in relation to the cost estimates?

A. MR. CAMPBELL: Yes. The cost estimates to rebuild the Mirrlees in our application here is three-quarters of a million dollars per megawatt, which means for WD1 to rebuild would be about a $4 million price tag, and to rebuild WD2, which is a megawatt larger, would be a 3.75 million dollar cost.

A. MR. MORRISON: Mr. Chair, I just want to complement Mr. Campbell's answer a little bit. There's a couple of things. First of all, those numbers are just raw engine numbers; they don't include the price, the cost of refurbishing the plant, which would have to be done in order to meet the standards of the refurbished engines, and that refurbishment lasts ten years. So if it's half the cost of new, in terms of the engine costs, and it lasts ten years, the economics are fairly poor when you can get 40 years plus out of a new engine.

But more importantly than any of those numbers, if we could make the numbers work, we can't -- we cannot -- and I can't -- I couldn't sleep at night -- we

can't get parts. It is almost impossible.

When we undertook FD1 and WD3, I personally went to MAN. They gave me assurances, and this was the only way that we proceeded, that they could supply those parts and they would be able to give us the kind of service and the parts servicing that we require. That did not materialize.

We had a dickens of a time getting parts in the end. These refurbishments took not just months longer, they took a year plus longer than they should have, that being a big part of the reason. In the end we had to try to get somebody to fabricate parts, which is not a good idea. We got parts that were completely ill-fitting, they didn't fit. They were the wrong dimensions. All of the capacity for building parts for these engines on a new basis has been outsourced to jobbers. There is no guarantee on quality on any of this stuff.

These engines haven't been made for -- and manufactured for, you know, 15 years plus probably, just even on the manufacturer's side.

So what you're getting is you're getting people where you can scavenge parts and you might be able to find some here and there.

We have numerous examples of ordering parts three, four and five times and never receiving them. And they sound like small things. The last one was -- is it's a

lower lube alarm on the Faro diesel. Well, you know, if there's no alarm and we lose the lube in that lower part of the engine, we could seize the engine. Even just getting things like that.

There is absolutely no way, in my opinion, that I could consciously agree to refurbishing these engines and sleep at night knowing that they're going to come on.

These engines are difficult at the best of times to operate. With parts that aren't working and breaking down, I don't see the reliability there.

Q. What upgrades have been made to the current WD1 and WD2 generators that have extended their life, if any?

A. MR. MORRISON: Well, I can't -- Mr. Chair, I can't answer in detail. They've had, you know, parts replaced from time to time. The biggest thing that's extended their life is they haven't run.

We went through a long period post the Faro mine shutdown where these diesels didn't turn a crank, and that is also part of the problem here. When we extended their life, when we did the FD1 and WD3 refurbishment, it was with the knowledge that we had a hydro surplus. We didn't need to run these engines. And the knowledge that we didn't have to run those engines gave us a lot of comfort.

We know today that we're going to have to run engines on an incremental basis to meet winter loads because

we've run out of that surplus. If we know we have to turn them on, the risk profile for me goes sky high and I'm not prepared to sign off on saying that these are reliable and we can run them on a long-term basis.

Q. So I take it that there were parts replaced in WD1 and WD2 generators, but they're worse than the complete refurbishments as it was in the other two cases; is that correct?

A. MR. MORRISON: Not in recent years in my memory.

Q. Okay. Now, with respect to the new diesel generators option, where would YEC acquire these units at prices that have been included in Table 4-3?

A. MR. MORRISON: Well, there's a number of options. The -- we have prices from engine suppliers. The options would depend on what sizes we wanted to put in and what the options were available for those sizes from different manufacturers.

We looked at Wartsila engines. We looked at Cats. Probably a Wartsila engine but it would depend, and Mr. Campbell is probably better at it than I to say from a size perspective whether they have engines that fit in there. But those are the kinds -- if you're looking for something representative in terms of the kinds of engines, those would be the kinds of engines we would be considering.

Q. Without being inundated with material, do you have a copy of the quotations and the additional detail that was received on these new diesel units?

A. MR. MORRISON: Well, I think we've -- just hang on a minute.

Excuse me, Mr. Chair, if you can bear with us, we're just trying to find this. We may already have some of that information.

THE CHAIR: Sure.

A. MR. OSLER: Okay. There is a response to YEC-LE-5 which attaches a request for information that was made on January 21, 2013 to various suppliers of engines to provide information on what they could provide to put into the Mirrlees bays, that we were looking at dual fuel as well as gas engines that was the focus.

And out of that, as described in the answer -- in this YCS 5 answer, the process eventually led to the selection of the engines that we're using for the modular gas units, but it also provided information that has been used to cost estimate the new diesel alternative based on the Wartsila information provided. And Mr. Campbell can elaborate on that if you need.

We did not provide in the record the information that we received from all of these various suppliers.

I would just emphasize that the focus was on engines that could be utilized in the Mirrlees bays which puts some constraints on size and that was of keen relevance to the company was what types of engines could be fit within these bays. The WD1 bay is slightly smaller than WD2, etcetera. So that was a very specific focus at the time.

And when you're looking at options for a new diesel, you do have to figure out where you're going to put them. And the assumption was they would be put into the bays of the Mirrlees that are removed, rather than building a new plant or something.

Now, Mr. Janigan, I don't know whether you're looking for more than that. If so, Mr. Campbell can --

Q. If you want to put some additional information, Mr. Campbell, I wouldn't object.

A. MR. OSLER: Well, what are you looking for in terms of -- are you looking for the cost basis that we've used in our analysis?

Q. Yeah, exactly.

A. MR. OSLER: Okay. So Mr. Campbell can elaborate then on how we took this information from this process, including the BBA study, which has also been filed in response to the YUB 13, one of the attachments there, in order to develop the cost estimates that are summarized in YECL 6, I believe, for the new diesel engine option.

A. MR. CAMPBELL: Yes. Well, the basis for our pricing for diesel-only engines started with us looking through the RFI process for a dual fuel engine, because at the time, the thoughts were that we would put these engines in the Mirrlees space. And we thought the benefits of having dual fuel with already having an existing bulk diesel fuel tank there would outweigh the costs, and that proved to be the case if, in fact, that would have been a feasible option.

From the work that we did, the incremental cost from single diesel to single gas, there was about a 5 percent adder, and to go from single diesel to dual fuel was a 10 percent increase in cost. So again, not a significant increase in the capital costs.

A. MR. OSLER: Mr. Campbell probably would elaborate a bit. It would help. There's the cost of the engine from the manufacturer and all that type of stuff, but there also were the cost estimates that BBA provided and are attached to YUB 13 --

A. MR. CAMPBELL: Sure.

A. MR. OSLER: -- that get you into why the cost is not a million and a half a megawatt but closer to 2.4 as given in the numbers, and you have to understand the balance of plant work.

A. MR. CAMPBELL: Yes. BBA undertook a fairly intensive study into what would be the costs that the utility

would look at having to undertake in order to fit some large diesel engines or gas engines in the Mirrlees bays. And in fact Mr. Osler is correct, the cost of the engines was a significant but not the total price. There was a very significant cost to refurbish the panel of plant work within the Mirrlees bays that were either end-of-life or would require an increase in capacity to handle the larger engines.

The air handling system would have to be upgraded to handle the larger engine. The cooling systems would have to be upgraded to handle larger engines. The switchgear had to be replaced in any case because, again, it was 46 years old.

So there was a number of balance of plant work, civil work, mechanical work, electrical work that would have to be done in order to put any type of new engine into the Mirrlees bays.

Q. Okay. Thank you. I'd like to move to another area, and in this case I'm going to deal with my book of cross-examination materials.

MR. JANIGAN: Can the entire book be marked for identification purposes, Mr. Chair, subject to what we've said in terms of its ultimate faith?

THE CHAIR: I think what we -- I understood what we had agreed to is we would just mark the --

MR. JANIGAN: The exhibits themselves?

THE CHAIR: So if you -- again, say you were going to page 6 to 8, then we would mark that as an exhibit.

MR. JANIGAN: That's fine. I'll just call it my book then.

THE CHAIR: That's fine.

Q. MR. JANIGAN: Panel, in response to our interrogatory UCG-YEC-1-3, YEC stated that the results of the March 2011 Energy Charrette provided an impetus for further research into LNG. And as well if you could turn up YCS/LE-YEC-121(c) -- and that's YCS/LE-YEC-121(c) -- that there were 12 possible short-term, i.e. 2015, energy choices evaluated by the stakeholders involved in the day sessions of the Charrette, and LNG was seventh on the list that participants proposed.

Have I summarized the answers in those two interrogatories correctly?

A. MR. MORRISON: I haven't checked them in detail, but subject to check, sure.

Q. Okay. Now, I wonder if you could look at page 197 of my book.

A. MR. MORRISON: 197?

Q. Yes, please.

MR. LANDRY: Maybe this is a good time to have a preliminary discussion about this book so that we

could, Mr. Chair, understand the position that Yukon Energy will be dealing with here.

If we could just start with the table of contents so that we can have a sense of where we're at here. And I would also refer, Mr. Chairman, to your -- to a letter from the Board to Yukon Energy and the interveners, which is Exhibit A-11. And this relates to the whole issue of what is on the record and what is not on the record.

You will recall A-11 is in relation to a request by the Utilities Consumers Group regarding hyperlink documents. And it was in reference specifically to YEC and YESAB websites. And the ruling that was made by the Board at that time was that the parties had the capability to put in evidence, but those wouldn't be on the record unless parties put them in evidence.

So with that sort of a bit of a backdrop, Mr. Chairman, if you look at the table of contents, items 1, 2, 3, 4 -- I don't know the numbers -- I guess, I've handwritten it.

MR. JANIGAN: The 6 has been removed.

MR. LANDRY: 6, yes. 6 and 5, the LNG presentation, and number 7 are not on the record. Most of those, with the exception, obviously, of 1 and 2, and I'm not sure about 3, most of them are documents that obviously would be on YEC's website.

So we're at a situation which was effectively pre-identified in Exhibit A-11, which is their documents that are now as aids to cross and then ultimately, I assume, to try to get in as evidence by way of exhibit with some very documents that we're talking about; in other words, that were talked about in Exhibit A-11.

Obviously some of these documents are Yukon Energy documents. They're from Yukon Energy's website. So any Yukon Energy senior management would no doubt be able to answer questions on them. That's not the issue. The issue is the process that's been established by the Board.

I can say that, you know, subject to foundational requirements for an exhibit and relevance, which obviously you would have to determine, any YEC documents, obviously the panel could answer questions on them.

Something that's not a YEC document, like items number 1 and 2, we will be objecting to. And I've informed my friend of that.

So that just provides a bit of background for the purposes of the first one that we're referring to, which I believe was -- which page was that, Mr. Janigan?

THE CHAIR: I think it was 198, or 197.

MR. JANIGAN: Mr. Chair, if I could interject here. These materials are not offered for the purpose of being put in evidence for the truth of what they contain.

They are before you for the purpose of -- only for the purpose of cross-examination. It is the responses of the panel that become the evidence in relation to their response to whatever is in these materials.

The materials themselves are not evidence per se. They are -- effectively form the basis of whatever response on cross-examination I get. But just to be clear on this -- because I don't necessarily think I -- I think I've been guilty of obscuring the issue before -- these materials are only for the purpose of cross-examination. If at some point in time the panel said, "I have never seen this before. I have no -- I have not dealt with it. I have no idea whether it's true or not," and that's the end of the story.

The exhibit itself does not become evidence of what it says. All that's in evidence at the end of the day is the testimony from the panel that says, "I have no idea what this is and, accordingly, I can't answer any questions on it." That's the only evidence that exists.

THE CHAIR: So could you not frame your question in a way that, you know, you may have the reference to the information, but -- as Mr. Landry said, that in theory, at least the YEC documents, the panel should have understanding or recall that information or be familiar with the content of that information? Could you try to proceed on that basis?

MR. JANIGAN: Well, yeah, I think that's essentially what I'm attempting to do. Looking at the document -- looking at particular phrases or sentences in the document and then asking questions based on that -- on their knowledge of the document. But the document itself -- the Charrette report has not been put in evidence by us. All I'm doing is using it as a basis for cross-examination. Hence, I haven't gone through the process of putting in intervener evidence per se on any of this. Number one, because it's been difficult from the standpoint of hearsay; but, secondly, it's not necessary for the purpose of my cross-examination.

And it's only the answers from the panel that I'm interested in in getting. I'm not interested in getting all of this into evidence as -- if that's helpful to you, Mr. Chair.

THE CHAIR: Mr. Landry, did you have any further comment?

MR. LANDRY: Mr. Chairman, I'm not sure that it's this document specifically that I'm overly concerned about, but I think it's the issue of just process and precedent. And I think you put it very well at the beginning, that if there is a question that can be put to the witness without the assistance of the aid in cross-examination, then it should be put to the witness.

In the case we're talking about here, given

what Mr. Janigan is saying, in my submission, the appropriate way to do it would be to say it's not in evidence. You say, "In your Charrette report, can you confirm that this was what was said?" It doesn't bring the Charrette report in. And, presumably, I know these witnesses are quite familiar with the Charrette report, having actively taken part in that, as did I.

So I think that's the appropriate way to do it. It's not this one that I'm overly concerned about. I'm just talking about in terms of how it's properly done.

THE CHAIR: Well, with that understanding can we proceed on that basis, subject to Mr. Landry objecting through the process of items that you might raise?

MR. JANIGAN: Certainly. I think for the purpose of precision, when it comes to things like the Charrette report, it's best to refer to the actual segment before I ask the question because it gives the panel the chance to reference what exactly I'm talking about. And it's their own document, so it can scarcely be prejudiced. But I will try.

Q. I'm looking at page 197 where it indicates -- which is page 16 of the Charrette report, that:

> "While there was not full consensus among the nine groups, or even among individuals within each group, there

were some common themes and predominant views that emerged from the game. The main realization was decision making is complex and involves a number of tradeoffs. The second was that, selecting short-term solutions was not as hard as selecting medium term and long term solutions, as the future is hard to predict and uncertainty increases risk. The chart on the previous page demonstrates some of the energy cards that were selected as a means of meeting each of the scenario targets."

Can the panel tell us how many stakeholders were involved in the game that determined the list of energy choices and who these stakeholders represented?

A. MR. MORRISON: Now, you are taxing my memory but 120, 130 people is my memory of the attendance at the Charrette.

Q. Okay. Does the YEC consider that the number of individuals that were involved in the Charrette to be enough of a representation of the population to competently say that YEC has been given a mandate by Yukoners to develop the LNG energy choice?

A. MR. MORRISON: I don't think we looked at the Charrette or any of the consultations that way. We were not seeking a mandate from anybody. I don't think we asked people to come there to give us a mandate. I think there's a lot more work that goes on in planning and the development of projects and a lot more stages including a YESAB review and a regulatory review before I would say that we would have a mandate. I don't think anybody asked people there to say, "You are giving us the authority to go ahead with something."

Q. Do you recall how LNG ended up being seventh on the list of energy options? Was this based on a voting system?

A. MR. MORRISON: It was a -- it was a game of different -- or an exercise of different small groups going through options and coming up with it and ranking them on a flip chart.

Q. Okay.

A. MR. MORRISON: But, Mr. Chair, I want to caution again. This exercise was about energy. We're talking about capacity.

Q. Can YEC confirm that the enhancement of existing diesel generators was also raised at the Energy Charrette as a viable short-term energy choice to pursue?

A. MR. OSLER: I can remember that we talked about diesel as an alternative default alternative. I think I gave a presentation on that. But I'm not sure we got into

specifically an option called enhancement of diesels. I think it was just a fundamental background in Yukon with an isolated grid, the need for flexible reliable capacity and last resort energy has been there a long time with the diesels. And I think we also went through the history of how renewable resources have developed -- that we now have in Yukon have developed by replacing diesel in the past largely related to large mine developments on the two grids.

Q. Now, on March 24th, 2014 in response to Board Order 2014-004, YEC filed presentations from the January 2012 LNG workshop provided by three consultants. Is that correct?

A. MR. MORRISON: I believe so, yes.

Q. Were these consultants contracted by YEC to prepare and deliver the presentation for this LNG workshop?

A. MR. MORRISON: Yes.

Q. And were these costs included in revenue requirements being recovered in rates?

A. MR. MORRISON: Mr. Chair, we'd have to -- we'd have to check. Our memory is just not good enough to answer that at this time. So we will -- we will -- we'll get you an answer, Mr. Janigan.

Q. Thank you, panel.

MR. JANIGAN: Can I get an undertaking number? I've forgotten the protocol for who do I ask an undertaking number from.

MS. BENTIVEGNA: We don't do that. We just keep track of them and then to make sure at the end.

MR. JANIGAN: Okay.

THE CHAIR: But it's good referencing that we are taking an undertaking.

A. MR. OSLER: What we're specifically going to check is whether these were part of costs that were brought into rates in 2012/13 or whether they were part of work in progress to be brought into rates at some future time. That's what we're going to check.

Q. MR. JANIGAN: That would be fine.

UNDERTAKING - TO CHECK WHETHER THE NUMBERS IN THE PRESENTATIONS FROM THE JANUARY 2012 LNG WORKSHOP PROVIDED BY THREE CONSULTANTS WERE PART OF COSTS THAT WERE BROUGHT INTO RATES IN 2012/13 OR WHETHER THEY WERE PART OF WORK IN PROGRESS TO BE BROUGHT INTO RATES AT SOME FUTURE TIME

Q. MR. JANIGAN: Now, on page 216 of my book --

THE CHAIR: Mr. Janigan, just to clarify, are you changing topics now?

MR. JANIGAN: I'm in another -- I'm in another piece of materials.

THE CHAIR: Okay. Because I guess what I

want to just clarify the ones that you had referred to earlier dealing with the Charrette, I'm of the view that you don't actually need to give that an exhibit number because I think you adequately were able to extract the information that you had in front of you to provide that to the panel, and they were generally able to respond to those questions.

So the exhibit may have been of value to you as an aid memoir, but I don't think it needs to be given an exhibit number.

A. MR. JANIGAN: I think that's fine, but I'm not so completely -- I can't remember my cross-examination so directly that there's not somewhere else that I might deal with the Charrette report. So if we could put that to one side and with that thought that if that's the end of the cross-examination and then we don't need the exhibit, that's fine.

THE CHAIR: That's fine. I'll just put that aside. We won't give it an exhibit number at this time.

MR. JANIGAN: Okay.

Q. MR. JANIGAN: And I'm dealing with your presentation, Mr. Osler, on 216 of my book. And on slide 1 -- actually, I guess that's slide 2.

A. MR. OSLER: I believe this particular presentation, if I'm not mistaken, Mr. Janigan, is in evidence.

Q. MR. JANIGAN: Is in evidence as well?
A. MR. OSLER: I think it's in Exhibit B-11 that was filed in response to a Board direction with respect to UCG questions. Subject to check, I believe this one is already there. Everyone is nodding at me, so we don't have to argue about this one.
Q. On page 2, I guess it was the second slide, I believe that you state under the LNG transition option that in the longer term there is a potential transition to other resources within the next 10 to 20 years.
A. MR. OSLER: Yes.
Q. And on page 222, you appear to expand on that thought by stating that this longer term transition option includes the potential transition to future local natural gas supply and the potential transition to new renewable resource development opportunities.
A. MR. OSLER: Yes. And in that particular workshop, I believe there was a representative from Eagle Plains or the development group that was talking to that particular potential, and all I was referring to was that people were talking about that at that time as a potential longer term development in Yukon.
In terms of the transition to new renewable resources, that was a fundamental thrust of the entire discussion around LNG at the time, that it wasn't viewed as

any more than diesel is viewed as a long-term energy option. It's there as a default option until such time as you can get the loads required to develop cost effectively the type of renewable resources we were discussing earlier that were capital-intensive resources such as hydro or wind.

Q. I guess what concerns me when I see that there may be a potential transition to other resources is what that means in terms of projecting the economic viability of the LNG Project forward if, in fact, we're looking at a transition to other resources in 10 to 20 years.

A. MR. OSLER: Yes. Now, the project we're talking about today, Mr. Chairman, was not envisaged at the time of this workshop. To be very clear, the discussion at this time was around what Mr. Morrison calls energy, yeah. And essentially we were looking at energy options, we were looking at possibility of Victoria Gold in a scenario that was the key focus for LNG options which would expand the requirements for default diesel up to maybe over 100 gigawatt hours a year but only for seven or eight or ten years.

Today, as we've said over and over again, we're looking at an option that is focused on capacity without any new big mines connected to the grid. In fact, Alexco is assumed not to be operating even though it was operating not that long ago, and it may be operating again according to it by 2015.

We are looking at a capacity requirement and saying that, one way or the other, you have to put in place new capacity and the capital cost associated with that, and by using LNG, we can save some costs on fuel going forward.

Now, whether we're talking about potential new renewables in the future or whether we're talking about compression of the difference between gas and diesel fuel prices in the future in some decades away, these are all good questions about what's this look like in terms of its economics, not just for the next few years as we show in Exhibit 3-4 but over the 40-year life.

I think, in summary, our evidence is as follows: Table 3-4 shows that the amount of fuel savings in the first four years is more than sufficient to cover the extra capital cost associated with selecting LNG and putting in place LNG facilities rather than diesel. And under various scenarios that date might potentially be shifted a year or so, but the point seems to be that this project pays for itself very quickly.

After that time, as long as the price of gas is less than the price of diesel, this project will continue to yield benefits. To the extent that we can -- Yukon Energy, Yukoners in general can develop renewable resources in the future to reduce the reliance on fossil fuels, that will be consistent with what I was talking about

in the seminar in January 2012 and consistent with the policies and objectives and goals of Yukon Energy, and it would not threaten the project's viability at all, for the reason I just gave.

Q. Which is effectively because of the short -- the pay-off in the short-term --

A. MR. OSLER: Right. Exactly.

Q. Okay. Now, in relation to these new renewable resource opportunities or future local natural gas supply, I think you've referred to -- I think in Slide 14 from your slide, which is page 222 of my book, you referred to Eagle Plain --

A. MR. OSLER: Right.

Q. -- as an example of the Yukon gas supply service. Is that an outlie or is that just another example of a number of different opportunities?

A. MR. OSLER: There were representatives of that project in the workshop. So I don't think they would describe themselves as an outlier.

All I can say is that in dialogue at that time it was necessary to make sure you referenced the fact that these people are developing and trying to develop the Eagle Plain resource, and they were starting to focus on gas and not just oil. And whether that evolves, when it evolves, and how it evolves is something I can't help you with. I just know that at that time, and particularly in that

workshop, it was necessary to make sure it was referenced because there were people there who were going to speak to it and talk about what they saw for the future.

I can say without any vagueness at all that this project that you're reviewing today in no way, shape, or form relies upon, contemplates, or anticipates getting gas from inside Yukon. It is entirely reliant upon getting reliable gas supplies from either Alberta or British Columbia from reliable gas operations and developments.

During the course that we've been working on this, the people in Inuvik have been through the experience of losing a gas supply or seeing it drastically reduced much faster than they thought it would be and having to find alternative fuels, which has led to anti-energy shipping gas before we are from Fortis all the way up to Inuvik through the Dempster Highway.

We do not want to rely upon a gas supply that is in any way, shape, or form risky, undeveloped, or potentially likely to be diminished in that manner.

Q. Am I correct in saying that Eagle Plain then is just one example of a potential Yukon gas supply source? Is that correct?

A. MR. OSLER: It was only intended to be that in this case and it was the one that had people present to discuss it.

Q. So there are others, obviously?
A. MR. OSLER: I think if you research it, there probably are potential other supplies, as well as supplies that technically arise in Yukon but are shipped south into Spectra or other source processing operations in Fort Nelson.
Q. Now, in relation to new renewable resource development opportunities, what were you referring to there?
A. MR. OSLER: We were looking at -- the resource planning process that we were in the middle of -- Yukon Energy was in the middle of was looking at all the renewable resource options, including all the ones that were listed in the original IR you referenced.
So in terms of longer term, they would be greenfield developments of either hydro or wind, they were probably the big focus of attention at that time, and particularly hydro in terms of Yukon has a very wide -- the resource plan summarizes the extent to which Yukon has a documented and extensive potential resource development with respect to hydro at various scales and various cost ranges and in various locations that could potentially be relevant.
A. MR. MORRISON: And just to add, Mr. Chair, the list also included at that time biomass and waste energy, projects which we have investigated to a level at which we, you know, are no longer pursuing them as active projects but

we did examine them. They were worthy of examination and were on that list of projects that Mr. Osler just referred to.

Q. Would it be fair to say that but for the relatively quick payoff of the LNG Project that these developments may be more significant in relation to evaluating the economic feasibility of LNG?

A. MR. MORRISON: Maybe just for my understanding, you mean the renewable developments?

Q. Renewable and the possibility of natural gas coming onstream.

A. MR. MORRISON: Sorry. Maybe you could just give me your question again.

Q. I would say but for the fact that in the short-term this project has a payoff that justifies it economically, that the developments with respect to potential gas supply source in the Yukon or renewables may be more significant in relation to the analysis of the viability of the project.

A. MR. MORRISON: Well, Mr. Chair, let me start, and maybe Mr. Osler will jump in.

I'm going to sound like a broken record, but the renewable projects that we looked at -- and we did actually look at the possibility of biomass as a renewable that might fit this whole issue of capacity and backup, because it could be dispatchable, it's too expensive. That

one was taken off the list in that context.

Gas supply being closer to the Yukon -- and I don't know what gas supply might be from a Yukon source, I have no -- no knowledge of anything around pricing of local gas supply -- might be cheaper, but so might other options, you know, peripheral to Yukon such as Fort Nelson or Fort St. John or Dawson Creek. I have no knowledge of how those might compare.

Renewables -- Yukon Energy has a renewable energy strategy. We have a resource plan that has clearly outlined what that strategy is and how it might go forward. We have shelf-ready projects that could be implemented as necessary, depending on the load scenarios. And our job is to balance not only the need but the -- and I've talked about this a number of times. It's the right project and the right place at the right cost at the right time. And it's a tricky job to balance all of those.

This project is very different. This is a requirement to shore up our currently required capacity backup system in order to make sure that we've got dispatchable, flexible generation available to us when we need it in the case, first of all, of an emergency; second of all, of a drought; and, third, to bridge that gap where loads are incrementally small enough that we cannot afford as ratepayers to have high-priced assets sitting there in order

to bridge that gap.

And when you look at those three in combination, that would be my answer. I think those are the fundamentally important parts here. I'm not sure that I would agree with Mr. Janigan's assertion, but I'm not certain that I really understood it either as well.

Q. I guess to paraphrase, Mr. Morrison, that this project, even without the overwhelming advantage of the price advantage that gives it an early payoff in the first few years, this project would still be chosen by YEC as a better alternative to new nonrenewables or a new gas supply?

A. MR. MORRISON: Let me try it again. This project, for the purpose of capacity, is one of two options that we -- that really vie for the competition -- vie for going forward as realistic options; and that's new diesel or gas.

These are capacity projects. They don't really relate to renewable projects in that same sense. We're not building for energy and we're not trying to replace energy. We're building for capacity.

Q. Okay.

A. MR. OSLER: Mr. Janigan, renewable is not a competitor for what this project need is. And that wouldn't change whether we had no access to gas at low price or not. It would simply be a new diesel versus the other types of

diesel options that would have been debated.

So I think the key point that we were trying to make in the seminar in 2012, January, was the requirements for developing the capacities that exist in Yukon -- the capabilities that exist in Yukon for abundant hydro resources clearly depend upon having the load.

I've never had difficulty having a discussion with someone understand that a large hydro project may have a levelized cost of 5 cents a kilowatt hour if only we had the load. Without the load it's a heck of a burden on anybody who has to pay for it: government or ratepayers.

And we've learned that -- I would have thought in Yukon -- when we developed hydro resources and the grid in response to United Keno Hill mine in one case and the Faro mine in the other case. And when I first came to Yukon, it seemed to me that my prime preoccupation was discussing how to deal with the rate implications of the Faro mine closing. Or opening again or closing again.

And when Yukon Energy bought the assets from Canada, the first thing that I was aware of was the United Keno Hill mine was going to close.

So does that mean it was stupid to build those hydro assets that lead to lower rates in Yukon today than anywhere else in Northern Canada? No. We've lived through the problem of the surplus and then no longer a surplus, and

we're going through a new transition again today.

But that history to me would teach me, anyway, that eventually when the load is there on a sustained basis for not just a few years, but not just five or ten years in some short-term mines, but something that's 20 years or more, you will have the opportunity again to develop cost-efficient Yukon hydro resources and perhaps somewhere in that process also wind. So that's all we're trying to say. If you don't get the load that justifies somebody investing that money, you won't get the resource development we're talking about.

So if the gas helps Yukon be competitive so that you get loads being developed, it will speed the day that you get the renewable resources developed. That's all we were trying to get across, because it's so difficult to develop them and do the planning required for five to ten years' worth of work on a hydro project if nobody knows how we're going to finance it when you're finished it, or how it's going to be cost efficient or get through a Part 3 application before this Board.

Q. And a combination of local natural gas supplies and gas storage is not a option for building capacity?

A. MR. MORRISON: I don't know if it is or not. I don't know when, I don't know -- I don't know whether there is one or not. I don't know anything about it.

Q. Have you heard of a feasibility study involving the

Vuntut Development Corporation in partnership with First Nations?

A. MR. MORRISON: Have I heard of it? Yes.

Q. Yes. And have you been involved -- has YEC been involved in any way with the study?

A. MR. MORRISON: No.

Q. If a representative of that corporation made a claim that natural gas could provide anywhere between 40 to 100 megawatts of power for Yukon's energy grid, what would be your response?

A. MR. MORRISON: First of all, a claim, I would -- my response would be I have no idea whether they could or couldn't.

Q. And you haven't done any analysis with respect to Vuntut Development Corporation's plans or Eagle Plains' capacity in a general sense?

A. MR. MORRISON: I can tell you, Mr. Chairman, I don't know anything about those plans.

Q. Has the Yukon government had any role in getting YEC to pursue the conversion of its diesel generators to use liquefied natural gas?

A. MR. MORRISON: Mr. Chair, the natural gas initiative -- the LNG initiative is an initiative of Yukon Energy. It was developed by us. We have -- we have not been directed, instructed by anyone to pursue this initiative.

Q. On page 224 of my book, in his presentation at the January 2012 LNG workshop, Mr. McCallum claims on slide 4, which is actually on page -- yeah, it's on, yes, 224, that natural gas is a cleaner burning fuel compared to diesel, resulting in fewer human health-related emissions.

Is there anything in the evidence associated with that particular claim?

A. MR. OSLER: I don't think we've added anything else to what Mr. McCallum presented and this also is part of the Exhibit B-11.

Q. Do you know --

A. MR. OSLER: There has been evidence filed with the YESAB report and process on anything to do with emissions in Yukon and safety and everything else. So there could well be in that mixture of material more information on emissions from diesel versus gas at Whitehorse in the past, and Mr. McCallum was looking at a pretty broad spectrum there. He's got YEC current there, I see.

Q. I guess the question is, is there something specific that he may have been referring to here, a specific study or report associated with the comment that natural gas is a cleaner burning fuel than diesel, resulting in fewer human health emissions. I think the first part of the statement may be noncontroversial, but the second was --

A. MR. OSLER: Well, human health related

emissions would be emissions that people are concerned about, particulates and other things like that. And I know that in the YESAB submission, there are comparisons made on that and there is a comparison made on emissions from new and existing diesels versus gas burning, and it supports the same points here. But, if necessary, we could -- I believe there's probably an answer in the record which I could find afterwards.

Q. If you could find that for me without -- I don't want 35 studies on the issue.

A. MR. OSLER: No. On emissions, particularly you're looking for, and I think we have an update and I think I can get the reference for you after the break.

THE CHAIR: Mr. Janigan, I'm just looking at the time here and I don't want to interrupt you in the middle of a questioning, but it's about 12:05, but you can continue on if you'd like to for a little while longer and then --

Q. MR. JANIGAN: I'm afraid I've forgotten the schedule that you --

THE CHAIR: We're going to go from 12 to 1:30, so that would be the break period.

MR. JANIGAN: Okay. Well, that's fine. I'm prepared to adjourn my cross at this point.

THE CHAIR: Just for the record, because

many of these documents that you've been referring to from your book -- and that's been all right in terms of reference, as been noted, they are on the record, and I'd just like to -- so we can go back and if anybody was reading those transcripts would know where the documents are included. These are in B-11. I think that's -- and then there's various attachments 1s and there's various subsections of those pieces of presentations in that attachment. Just so the record is clear in terms of those being on the record already. Thanks very much.

So we'll adjourn now and resume at 1:30.

PROCEEDINGS ADJOURNED TO 1:30 P.M.

Volume 1
March 31, 2014
P.M. Session

THE CHAIR: Please be seated. So before we begin this afternoon, are there any preliminary matters?

MR. LANDRY: Just one, Mr. Chairman. From our perspective we have one undertaking that we can give an answer to now.

THE CHAIR: Okay. Please proceed.

A. MR. OSLER: I think it was right near the end we were discussing where we could reference in the IRs materials and omissions. And I can give you CW-YEC-1-1 item I, which has reference two attachments to that IR, which give emission information from the SF filing. And I could also reference you to Exhibit D-11, which includes the draft screening report from the SF. Sections 6.2, 6.3, and 6.4 deal with their draft screening report on emissions for this project.

MR. JANIGAN: Thanks very much.

A. MR. OSLER: Thank you.

THE CHAIR: Unless there's any follow-up, Mr. Janigan, you can proceed from where you were.

MR. JANIGAN: All right, thanks. I have a little difficulty remembering where I was, but...

Q. Panel, I wonder if you could turn up in my book page 25. And this is part of a document entitled an "Application for Yukon Land and Subdivision Approval" dated August 2013. And I want to look at the second-last page of the document, which is on page 25, or page 3 in the actual way the document was paginated. And that is the section that says:

> "Cost savings resulting from the Project will benefit all Yukon's electricity customers beginning in 2015 ($2.7 million) and increasing to $4.2 million in annual savings by 2017 and are directly related to decreased use of diesel. These cost savings are based on a 30 year rolling average for water availability and current load growth projections. It is anticipated that savings will continue to increase each year thereafter over the life of the natural gas facilities as diesel displacement increases."

My question is, how do we reconcile the cost savings that are listed in the land acquisition application to the cost savings listed at Table 4-3 in the application?

A. MR. OSLER: I'm looking at the application, Table 4-3, the numbers that were there at that time, and I'm

looking at what you just put in front of me, which I hadn't seen before. I'm not sure how what you've just put in front of me derives from the application, so...

Q. When you say "the application" you mean --

A. MR. OSLER: I mean the application that was filed by YEC on December 9th to the minister.

Q. Oh, okay.

A. MR. OSLER: So the date of this document seems to be July 2013. So you'd think they'd be the same. So at the moment, off of the top of my head, I can't help you. I have to go and find out where this document came from.

Q. Who compiled this document? Do you know?

A. MR. MORRISON: YEC compiled it, but what Mr. Osler is referring to is how the numbers are different.

Q. Yes.

A. MR. MORRISON: And certainly Mr. Osler didn't compile them.

Q. If you could undertake to just tell me how and why the numbers are different, that would be fine.

A. MR. MORRISON: Sure.

UNDERTAKING - TO ADVISE HOW AND WHY THE NUMBERS ARE DIFFERENT BETWEEN THE "APPLICATION FOR YUKON LAND AND SUBDIVISION APPROVAL" DATED AUGUST 2013

AND TABLE 4-3 IN THE APPLICATION

Q. MR. JANIGAN: In response to UCG-YEC-1-5(c), there's set out therein that YEC indicates that the actual diesel generation at Whitehorse in 2010 to 2013, and it's listed numbers there, 2010 at 2.417 gigawatt hours, or .6 million, etcetera, etcetera, all the way down to 2013.

In Table C-2 of Appendix C of the application YEC provides forecasts of average diesel generation at different forecast loads for the period of 2013 through 2030.

My question is, have you put information on the record for forecast diesel generation and related costs just at Whitehorse for the 2014 to 2030 period?

A. MR. OSLER: No.

Q. Is that information easily referenced?

A. MR. OSLER: You're talking about the forecast period?

Q. Yes.

A. MR. OSLER: What the application does is talk about operation with the new gas engines and assumes that the gas engines would be given first ranking for operation on the grid. So the assumption is that the gas engines will displace the diesel as discussed on the whole grid.

In that sense the application addresses the impact on the grid's operations and not just Whitehorse. But

it's all focused on fuel and diesel operation and not getting into other details.

Q. Is what you're saying, it's likely a distinction without a difference?

A. MR. OSLER: I can't help you on that. I can just say what I said is reflecting what we're doing.

Q. Okay. What I understand you saying is that because it had first priority, effectively it represents actual diesel generation at Whitehorse in any event. Did I get that right or wrong? I'm talking about Table C-2 here.

A. MR. OSLER: Table C-2 is a forecast of the grid. It's got nothing to do with saying which generating stations are used to meet that default diesel requirement.

Q. Okay.

A. MR. OSLER: The application is taking those numbers of the forecast for long-term average diesel requirements on the grid and saying that they can be displaced by the gas engines at Whitehorse as discussed in the application. There is an IR that makes the point that there can be various other things that could lead to diesel operation on the grid that are not covered in Table C-2.

Q. Okay.

A. MR. OSLER: They would be fires, capital projects, short-term emergencies, things like that. And those are not discussed or covered in the forecasts that

we're covering because they're basically something that you don't sit around forecasting.

This is long-term average diesel requirement based on the -- Yukon Energy's models as to how much on average over the 31 water years the energy load would have to be met by thermal generation.

Q. Okay. So I guess where you're pointing me is that if I want to look at a forecast -- actual diesel generation at Whitehorse as a forecast from 2014 onward, that would have to be a separate analysis?

A. MR. OSLER: If it was to be a forecast of diesel generation without this project and where would it occur on the grid, it would have to be a separate analysis, and we have not attempted to do that.

Q. Now, as I understand your evidence, the driving force behind the need for this project is in fact the need to replace aging diesel generators and not simply to capture fuel savings. Am I correct on that?

A. MR. OSLER: Yes.

Q. And I believe it's indicated at various places in the application that YEC based its cost-benefit analysis on the assumption that all capital costs would be depreciated over 40 years.

A. MR. OSLER: Yes.

Q. And does that mean that YEC conducted its analysis

assuming that all costs incurred related to the proposed LNG Project were depreciated over 40 years?

A. MR. OSLER: Essentially, yes.

Q. Isn't --

A. MR. OSLER: All costs incurred that were of a capital nature would be subject to depreciation. Obviously not fuel costs.

Q. Right. Isn't it true that many capital costs being incurred for this project will be depreciated over periods much less than 40 years?

A. MR. OSLER: Not to my knowledge, that I'm aware. Essentially the people in YEC went through and checked what we're talking about. And when you're looking at the major pieces of equipment that are involved in this project -- start with the diesel engines. If you were to operate those diesel engines at a high level of use, they probably would have a 20, 25-year life by most people's assessments. But the key to operation on this system is they won't be used intensively; they'll be used much more sporadically, and that's why they end up having a much longer life that we're talking about.

The same comment isn't perhaps not as relevant to some of the other equipment, the vaporization, storage tanks and basic infrastructure, but the assessment that Yukon Energy's people made after looking at those specific

pieces of equipment is that they have a life as well of at least 40 years.

So on that basis, all of the costs for the new diesel alternative or for the LNG Project, as it's being described here, are assumed to be depreciated over 40 years.

Q. What about if a transition option kicks in?

A. MR. OSLER: I don't --

A. MR. MORRISON: I don't know what you mean.

A. MR. OSLER: Can you be clear on what you're asking?

Q. What we discussed earlier, what about there's a potential transition to other resources?

A. MR. OSLER: Would something happen that would render this project obsolete? Is that the essence of the question?

Q. In essence, yes, and what occurs with respect to the unappreciative costs?

A. MR. OSLER: The transition concept wouldn't render the project obsolete. It probably would still be required even with a hydro development or wind development for reliable capacity on the system. What the -- what the renewable transition would do is displace the amount of diesel or LNG that needs to be generated by way of energy.

So if we -- one of the things we've resisted doing is showing a 40-year projection of these units and how

they would operate because after you get outside the four or five years that are used in the tables for the economic assessment, you're getting into a range of considerations as to what's going to happen. How much renewable energy is going to be developed and when? What loads are going to be on the system?

To assume that as you might do for resource planning base case that you would simply keep using diesel or LNG, would not be an appropriate assumption in terms of what would be really expected over time. And at some point, new renewable resources will come onto the system to displace use of thermal resources. When, which and how much cost we don't really have a basis for forecasting because there's so many variables that could play with it.

So if the project can be shown to be viable and recovering its key costs within four or five years, our conclusion was that that's -- if that's sufficient to make the point about the project's viability, let's not get into a whole bunch more complexity than we need to to establish the point.

But for development of renewables, transition in the future is an energy-focused exercise. I hope we've got that point across. And that will displace the need to keep relying on thermal units for energy. It will not displace the need to make sure you have reliable capacity

that can be flexible and reliably turned on by an operator when required.

So probably you will continue to need growing capacity for a growing system; and, secondly, new engines will tend to live their life if not longer -- you know, if you look at the ones that we're displacing, they lived a lot longer than anybody probably said they would live when they first were installed because the new ones will be the ones that you want to keep around.

In looking at the Whitehorse plant, all the other units are supposed to be retired, end of life, within, what, 13 years. This system has this problem around the whole system. So I would not be terribly concerned about future Yukoners not wanting to rely upon these units for at least their life.

Q. And I gather from what you've said effectively the need for backup generation, emergency generation, peak supply will continue and so that the need for these generators will likely continue as well?

A. MR. OSLER: That's essentially what I was trying to say.

Q. I wonder if I could turn you to the fuel adjustment rider and deferred fuel price variance policy, and that appears in my book in page 146?

THE CHAIR: Mr. Janigan, just before

they're looking for that document, did you wish to give this Yukon Energy Corporation document an exhibit number?
MR. JANIGAN: Yes, please.
MR. LANDRY: I'm not sure he needs to. He read out a quote. They acknowledged that and I don't think it has to be put into an exhibit. It's not on the record now. It's one of the documents that's not on the record. I think Mr. Janigan got what he wanted out of the question.
THE CHAIR: That would be my preference. I think it's self-explained in your questions.
MR. JANIGAN: I don't have a problem with that.
Q. MR. JANIGAN: Yes, on page 146. And this is a fuel adjustment rider and deferred fuel price variance policy that was submitted by YEC and YECL on January 20th, 2012, and as I understand, approved by the YUB in order 2012-02. I take it you're familiar with that policy?
A. MR. OSLER: Yes, generally. I wasn't in the middle of this, and the people here are not in the -- we're not in the middle of this particular set of details, but we are familiar with this policy and have addressed it during GRA hearings, yes.
Q. Does the current fuel adjustment rider policy make any reference to LNG?
A. MR. OSLER: I'm sorry, could you start that

again?

Q. Does the current fuel price adjustment rider policy, which I believe is on page 152, does that make any reference to LNG?

A. MR. OSLER: Not to my knowledge, no. It would not have been considered at the time that this was prepared.

Q. Does YEC intend to make application to the YUB to change the fuel adjustment rider and deferred fuel price variance policy to account for LNG?

A. MR. OSLER: I think the answer is yes. I mean, it hasn't been something that people have dealt with at the detailed level, but in principle, yes.

The concept of treating all of these thermal fuels the same way, both in respect to this rate Rider F policy and also with respect to the diesel contingency fund so named, I know that in the filings from the last GRA with respect to the DCF, the diesel contingency fund, the point was made that fund should be amended at such time as LNG or natural gas fuels were to be used for generation and to displace diesel. So in principle, yes.

Q. And with reference to Section 8 of Rate Policy Directive Order in Council of 1995/090 --

A. MR. OSLER: Where are you, Mr. Janigan?

Q. That's a good question. I can't find the page where

this is listed. 230. Thanks very much. The rate policy directive starts at page 230 and goes on to 231.

A. MR. MORRISON: Right.

Q. 232. I take it that Section 8, which is the fuel price adjustment, I take it that that would have to be changed to account for LNG as well.

A. MR. OSLER: Yes. In the sense that if Yukon government wants to make sure that it is getting an Order in Council directive with respect to fuel price adjustment that covers natural gas as well as diesel fuel, then on the face of it, it would need to amend that point. But you're asking -- you're starting to get into legal stuff.

Q. Yeah.

A. MR. OSLER: In principle, utilities do deal with fuel price adjustment without necessarily having to have Order in Council directions. And I think the company is making the point that it would, in principle, see the need to do this. There's nothing in here that says you can't do it. That would be my only observation.

Q. It can't be amended; is that what you're saying?

A. MR. OSLER: That's somebody else's job than Yukon Energy's if they want to amend it.

Q. Okay.

A. MR. OSLER: But there's nothing in here that says you can't have a fuel adjustment rider to also deal

with natural gas.

Q. Okay. On page 29 of its application, YEC states that for its cost-benefit analysis, it has assumed that an LNG cost of 4.5 per million BTU.

A. MR. OSLER: That's an AECO Gas price assumption in roughly three quarters of the way down the page that you're referring to?

Q. I believe so, yes.

A. MR. OSLER: Yes, and that assumption has been retained through the updates.

Q. Okay. And it's the price that LNG -- that all LNG used between 2015 and 2018 as well as in the longer term analysis?

A. MR. OSLER: We didn't vary the price by year. It was used throughout.

Q. Okay. Now, would you agree with me that the natural gas prices since 2006 have shown a lot of variation?

A. MR. OSLER: Yes.

Q. And in brief, you've seen spectacular decreases since 2006 with the coming onstream of shale gas and, of course, you've seen a bit of retreat in those price decreases in the last year or so largely driven by demand. Would you agree with that?

A. MR. OSLER: Yes. There was a material change in the natural gas market in North America.

Q. I guess the difficulty we're having is that given the

degree of change over the last eight to ten years or so, how can we view with confidence your estimates based on a fixed price of 4.5 per million Btu?

A. MR. OSLER: Well, the short answer is because the analysis indicates that the overall answer in the key conclusion is very robust to changes in that number. It's not dependent on $4.50 AECO price. That's the short answer.

The more important point substantively, in my view, is to what extent can you be comfortable that there will remain a differential between the price of oil, which is reflected in diesel, and the price of gas. Because the issue isn't whether it's 4.50 for gas or 5.50 for gas or 3.50 for gas, it's how big is the saving compared to diesel.

And the report, the filing addresses this on pages 40 and 41. And there have been some questions, and I'm sure there will be more during the course of this hearing, on this matter.

And I will just say it succinctly for now because I'm sure we'll come back to it. The evidence that we've been able to see suggests strongly that projections made by leading American government agencies, the Canadian government agencies see this price potential being three times or more for at least three decades.

Q. I take it one of the risks on this revolves around

whether or not the continued development of shale gas might be impeded by new environmental restrictions?

A. MR. OSLER: Sorry. Could you repeat that?

Q. Sorry. I take it one of the risks associated with natural gas prices and something that may cause increases is the risk that new environmental restrictions on shale gas development may come about restricting the flow of shale gas into the North American system.

A. MR. OSLER: I think that people trying to understand what might cause the current consensus to be changed would raise that as one of the potential risks, that the -- something, whatever, environmental or otherwise, would lead to a change in what people expect to be their capability of the shale gas in North America.

The key to what we're talking about is very definitely gas supply in North America relative to world oil price.

So, yes. If something was to radically rechange the perspective of natural gas in North America such that the expectations that are driving everybody's thinking at the moment was to change, then of course there could be implications to what we're talking about.

Q. But you're confident, based on the numbers you've submitted, that within a reasonable range of predictions that the LNG Project is still a go based on those range of

potential LNG prices?

A. MR. OSLER: Yes. And my thinking is very definitely shaped by the timing elements of what we've been talking about. It seems that people are reasonably confident, you know, at an unusually high level about what life is likely to be like in these markets for the next five to ten years. And, as we've said, the evidence seems to be that this project will recover its cost differential in terms of capital within four years.

After that point, once it's recovered its cost differential and capital through fuel savings, as long as the price of gas doesn't get to be higher than the price of oil, the project will continue to have been beneficial to ratepayers on an ongoing basis.

So I don't think I'm very -- I haven't heard anybody recently coming at me about the price of gas ending up being more than the price of oil. In my career there was a phase when people told me that, but it was a long time ago.

Q. Can YEC explain what work is needed to be completed on the diesel warehouse building and what costs are included in the project cost estimate?

A. MR. OSLER: Can we be clear that we're talking about the diesel plant; right?

Q. Yes.

A. MR. OSLER: And you're interested in

knowing what costs need to be incurred in that plant for what purpose?

Q. That are included in the project cost estimate.

A. MR. OSLER: That are included in this cost estimate.

Q. Yes.

A. MR. OSLER: At a high level, and I'll get Hector to check, to the best of my knowledge the costs that are included in this cost estimate relate to decommissioning of the diesel, the two Mirrlees engines, but no costs really for upgrading of the facility. That would be a cost that would have to be incurred in the future when somebody tries to put new engines in those facilities.

I'm not sure -- Mr. Campbell can comment whether there's anything else. We're putting pipelines -- pipes over from the LNG facilities to the diesel plant and you're going to run the boiler on that. You might want to elaborate on that. But I don't think there's any other costs other than connections of electricity and the gas.

A. MR. CAMPBELL: Sure. The scope of work for the LNG Project ends at the Whitehorse diesel plant wall. Okay? So it would include, you know, the piping over to the diesel plant and it would include, of course, the transmission line connecting to the S150 substation for the power.

Q. Was this work that was planned for future years that is now being brought forward? Is that fair to say? Or was this something that is very specific to the LNG Project?

A. MR. MORRISON: The only -- no, it's specific to the LNG Project.

Q. Okay. Is YEC aware of any analysis of emissions from LNG-fueled generators that could cause respiratory problems for people and animals living near such a plant?

A. MR. MORRISON: Mr. Chair, the emissions issue, from our perspective, has been thoroughly in a detailed manner dealt with by YESAB. We've provided what we, I think, earlier referenced by Mr. Osler as to what those emissions are, and the health, safety, environmental concerns related to emissions have been addressed by YESAB. We can look in the report and find some reference to it if Mr. Janigan would like, but I think the matter's been dealt with.

Q. Okay. Let's put it this way. YEC is satisfied that the YESAB report deals with this issue in a way which is conclusive for them?

A. MR. MORRISON: I believe so.

A. MR. OSLER: And they deal really in different headings. Emissions -- they also deal with health and safety in great detail. So very comprehensively.

Q. Okay. Now, in response to YUB-YEC-120(b), that's YUB-YEC-120(b), YEC states that the expected salvage value

for the diesel fuel generating units being decommissioned is not known at this time, but to the extent YEC is successful in generating proceeds from the disposal, this income will be offset against the cost of decommissioning the units. In other words, the net value is to be charged off to the reserve for future removal and site restoration.

A. MR. MORRISON: That's correct.

Q. My question is, in its cost-benefit analysis, how much has YEC included for additionals to the reserve for future removal and site restoration?

A. MR. OSLER: I'm not aware of any -- on the subject we're talking about, the capital cost estimate in YUB 1(d) talks about adjustments to the demolition portion of the cost estimate to reflect review, you know, of this matter. And so the costs that we're talking about that are in the project costs come from the demolition portion that's included in Table 1 of YUB-YEC-1(d).

And I think what people are trying to say here is they did not take into account any recovery of costs per se other than -- I think the comment was made that the costs for shipping materials would be recovered by the salvage. So they didn't include a cost for shipping.

But if they got something better that affected the future salvage fund, that's not taken into account or estimated here. They're just simply saying how they would

deal with it if the event arose. That's my understanding, sir.

Q. So it's not included then in the cost-benefit analysis. All right.

At an LNG public meeting on December 11, 2013, Mr. Morrison, I believe you stated that it appeared that YEC had a sale for the old Mirrlees to the B.C. Ferries; is that correct?

A. MR. MORRISON: No, not to my recollection.

Q. Did you ever make a statement similar to that at a meeting --

A. MR. MORRISON: No.

Q. -- about the sale of -- no?

A. MR. MORRISON: Not to my recollection anyway. You can show me something.

Q. Is it possible --

A. MR. MORRISON: What --

Q. Sorry. Go ahead.

A. MR. MORRISON: Sorry. I mean, you know, I don't think that I said that we had a sale of the engines to anything. If you -- if -- if -- and I would have to look -- I don't remember -- I said anything, I would have said that there may be a possibility that those would be the kinds of people we would look at in order to see if there was an interest in a sale because they have Mirrlees engines.

That's all.

Q. Okay. There's been no -- has there been any negotiations --

A. MR. MORRISON: No, there haven't.

Q. And no contract or sale --

A. MR. MORRISON: No, there hasn't.

Q. -- has been concluded?

Do you know if any party, such as the B.C. Ferries, have assumed that these units may have a useful life remaining in order to buy them?

A. MR. MORRISON: I don't know of that, no.

Q. Okay. In response to UCG-YEC-1-20(b) -- and that's the same interrog I was referencing before -- YEC states that:

> "... the Base Case with no Alexco is intended to be a conservative assessment of potential load requirements in the near term. The Base Case with Alexco would more closely resemble a 'likely' scenario at this time based on Alexco's stated plans to resume operation early in 2015."

My question is does YEC still consider the base case with Alexco in operation the most likely scenario?

A. MR. OSLER: Yes. I mean, in the sense that

when YEC's been asked, it has been informed, as others have, that Alexco is still planning to come back and start operations in 2015. So on that basis it is deemed to be a likely scenario if you're talking to people about what may occur. It's not a certain scenario.

So for the purposes of trying to do this economic analysis, people wanted to be very clear about what loads they could rely upon, but which was, therefore, the base case without Alexco. But the base case with Alexco has certainly been examined, and we can give you information on it. It simply increases the fuel cost savings such that they're bigger than what we've assumed in the analysis that you have seen.

Q. Okay. I'd like to ask you to turn up page 28 in my book that deals with the YESAB draft screening report of March 19th, 2014. And page 28 is the preface.

A. MR. OSLER: Just for the record, Mr. Chairman, this would also be Exhibit B-11. I believe it's been filed in response to that document, so it is on the record of this hearing.

THE CHAIR: Thank you very much, Mr. Osler.

Q. MR. JANIGAN: Now, in the preface, it states that:

"The Project lies within the traditional territories of the Kwanlin

Dun First Nation (KDFN) and the Ta'an Kwach'an Council (TKC), and within a developed part of Whitehorse."

My question is do these First Nations need to provide any approvals in order for the project to proceed?

A. MR. MORRISON: No, they don't, sir.

Q. Okay. In response to YUB-YEC-1-18(d), YEC indicates that: (as read)

"The Ta'an Kwach'an Council is no longer participating in partnership discussions and the Kwanlin Dun First Nation remains fully supportive of the proposed LNG project and is working with YEC on an agreement addressing service and supply contracting opportunities related to the project, provisions for an investment opportunity in the project, and access to any surplus, LNG surplus capacity and inventory as part of a potential physically and financially separate wholesale retail natural gas facility to be developed by KDFN."

My first question is: Why did the Ta'an Kwach'an Council end the partnership discussions with YEC?

A. MR. MORRISON: Mr. Chair, that's something I can't tell you. I'm not privy to their reasons or their -- and they've given me no reasons. So I have no idea.

Q. Has YEC finalized any agreements with the Kwanlin Dun First Nations?

A. MR. MORRISON: Perhaps for Mr. Janigan's assistance, we could call it Kwanlin Dun.

Q. Kwanlin Dun?

A. MR. MORRISON: And we have a project agreement with Kwanlin Dun. It's not detailed in any stretch of the imagination, but our original discussions with Kwanlin Dun and Ta'an were around the 25 percent investment by each of those First Nations in the project itself. When Ta'an decided to pull out, at the request of Kwanlin Dun, considered moving their investment from 25 to 50 percent in the project, and we have a project agreement that would allow Kwanlin Dun to make a 50 percent investment in the project as we go forward.

Q. And are they -- are they in agreement with that proposal?

A. MR. MORRISON: We have a project agreement signed by them outlining, you know, the general terms of that -- of that potential investment.

Q. When was that project agreement signed?

A. I don't have the exact date in my mind, but a month or

so ago.

Q. Okay.

A. MR. MORRISON: Two weeks ago.

Q. And if Kwanlin Dun takes an equity position in the proposed LNG Project, will that impact the debt equity percentage of project cost that YEC will attempt to recover in rates?

A. MR. MORRISON: No, it won't, sir.

Q. Could you explain that?

A. MR. MORRISON: Well, we have a regulated 60/40 debt equity ratio, and any investments would be along those lines.

Q. I'm talking about the project cost that YEC will attempt to recover in rates.

A. MR. MORRISON: I'm trying to relate to that, the total cost of the project, and the investment in the project will be based on a 60/40 debt equity ratio.

Q. Okay. But the equity position of your partner, won't that --

A. MR. MORRISON: It doesn't really matter where the equity comes from in terms of a project. It's a capital project that's got 40 percent equity and 60 percent debt. That's what it has.

Q. Won't a share of that be -- won't the partner be responsible for a share of that?

A. MR. MORRISON: Sure, but all that will mean is it's either us putting up the equity or somebody else putting up the equity. But I thought -- sorry, Mr. Janigan, I thought your question was would it fundamentally change the debt equity structure, and I don't think it will.

Q. No, I know the debt equity structure -- or the YEC won't change. I'm more interested in what's going to be recovered in rates.

A. MR. MORRISON: And I don't believe it will change that either.

Q. Are you aware that there's been a new chief of the Kwanlin Dun First Nation elected?

A. MR. MORRISON: I am.

Q. And have you spoken with her concerning this particular arrangement?

A. MR. MORRISON: I have not.

Q. Is her agreement with this arrangement crucial for it going forward?

A. MR. MORRISON: That, I don't know, sir.

Q. Do you know if she has changed her -- changed the position of Kwanlin Dun?

A. MR. MORRISON: I do not.

Q. When do you expect that you're going to find out about that?

A. MR. MORRISON: I think it will be on her

schedule. I'm sure she's very busy taking over her new job.
Q. Have you heard that she may be against this project?
A. MR. MORRISON: No, I haven't, sir.
Q. I guess -- what impact would Kwanlin Dun's pulling out of this project have on the overall LNG Project?
A. MR. MORRISON: Well, it would mean we'd have to rethink the quantum of equity that we would require from either our shareholder or internal sources. It wouldn't -- it wouldn't change the debt issue at all because we would borrow the money the same as we would otherwise if we required it. So I don't think -- on a financial basis, I don't think it has any impact.
Q. And it's not required for any approvals in this project.
A. MR. MORRISON: No, that's correct, as I mentioned.
Q. All right. Now, I wonder if I could flip back to the draft screening report on page 65, which is page 25 of the report. And about two-thirds of the way down the page, it indicates that: (as read)

> "YEC explained that installing new high efficiency diesel units would provide reliable generation capacity that is sufficient to meet forecasted thermal capacity requirements. The capital cost of new high efficiency diesel

units would be less than the proposed natural gas units; however, YEC concluded that the new diesel units would have a higher estimated fuel cost and produce more air emissions than the proposed natural gas units."

My question is, do you still agree that installing new high efficiency diesel units would provide reliable generation capacity that is sufficient to meet forecasted thermal capacity requirements?

A. MR. MORRISON: Yes, Mr. Chair. I agree that new high efficiency diesel units would give us the capacity, but however, the cost of operating those units when required is significantly higher than gas, and for that reason, we've put before you a proposal to use gas instead of high efficiency diesel.

Q. Would ratepayers see any change to their monthly bill due to implied higher emissions from high efficiency diesel units?

A. MR. MORRISON: Sorry, Mr. Janigan, are you talking about emissions?

Q. Yes.

A. MR. MORRISON: Well, they wouldn't see any changes to their bill related to emissions, but certainly, you know, the environmental impact would be higher overall

than the health impact.

Q. Can you confirm that YEC's updated Table 4-3 that was circulated on March 27th indicates that the capital cost difference between new high efficiency diesel units and the proposed LNG fuel generators is approximately 2.7 million between 2015 and 2018?

A. MR. OSLER: We can confirm that the annual charges for depreciation and return and the difference between -- in those charges between new diesel and LNG totals to approximately 2.7 million over those four years. The capital cost difference between those two elements is $9.3 million in that table.

And I would just for sake of clarity on the record say what Mr. Morrison said in his opening. The prime factor causing that capital cost difference is not the engines. It's the LNG infrastructure that's being introduced with the gas alternative, the infrastructure for unload, storage, and vaporization.

Q. We've been down this road before. There are no other material revenue requirement items that should be added to the cost portion of the updated 4-3 comparison?

A. MR. OSLER: Not that we're aware of, sir.

Q. Okay. Now, the draft screening report states on page 26, and page 66 in my book.

"YEC has committed to exploring and

developing additional renewable generation supply options to reduce both diesel and liquefied natural gas (LNG) requirements wherever possible as the requirement for default diesel generation increases."

My question is what exactly are these commitments and could they impact the amount of diesel or LNG used in the 2015-2018 time period?

A. MR. MORRISON: Mr. Chair, let me answer the last half first. No, there is nothing in there that will do that in that short a period of time, at least in my mind.

The commitments are as we talked about earlier. We a hydro-based utility. Renewables are the direction that the corporation will focus its efforts for energy purposes. But there have to be some -- there have to be some conditions that are met in order for us to move to the next generation of renewables. And those are, as we've indicated earlier, loads that can be maintained over time.

Now, we can do some small hydro. We can mitigate diesel or gas at the margins with projects like Mayo Lake storage and Marsh Lake storage, but they're 4 and 6 gigawatt hours a year respectably. We're not going to get away in the near term in the material way from what we see as the incremental diesel required to meet the needs of the

system over the next several years.

So our constant commitment is looking at what is the best alternative for ratepayers. Energy is very different than capacity. We've got a load, and we can put a long-term hydro or wind or, you know, maybe in the future solar project on the system. That's exactly what we'll do. But we have to justify those to this Board, and we've got to have loads that will be sufficient enough to cover those costs.

Q. Now, the draft screening report states on page 28, which is page 68 of my book:

> "The public comment period for the Project was from November 5, 2013 to January 10, 2014. The Executive Committee received over 130 comments during the course of the public review."

And then over on page 29:

> "The Executive Committee recognizes that the majority of comments received opposed the Project proceeding, as proposed, and has considered those comments. However, some of the concerns raised in the comments are outside the legislative authority of

what the Executive Committee can consider when conducting a YESAB screening."

My question is would you agree that the public comments submitted to the YESAB process were predominantly opposed to the proposed LNG Project?

A. MR. MORRISON: I wouldn't argue with YESAB's own report, no.

Q. Okay. Now, the draft screening report states on page 34, or page 73 of my book:

"The Executive Committee is satisfied the construction of a natural gas generating station will meet the purpose of the Project as outlined by YEC in the proposal."

And going back to page 11 of the report, or page 51 in my book, it has:

"The purpose of the Project is the construction of a new natural gas generating station and associated activities adjacent to YEC's existing primary power generating station, the WRGS. The proposed project will produce 13.2 MW, which will provide an additional 4.1 MW to the Yukon

electrical grid upon the decommissioning of the two diesel generators (total of 9.1 MW capacity) YEC intends to replace."

Now, would you agree that the draft YESAB report does not say that there are no alternatives that wouldn't also satisfy the same purpose?

A. MR. OSLER: The report says the same thing we're saying, that -- in fact you quoted it earlier, that the alternative of new high efficiency diesel is the alternative to compare the report to compare this project against.

So, as we said a few minutes ago, that alternative would achieve the same need, just more costly in terms of fuel. I think YESAB accurately reflected that in its report.

Q. In effect, YESAB reviewed the environmental socioeconomic effects of the proposed project but their mandate did not include reviewing the cost impacts to Yukon electricity ratepayers?

A. MR. OSLER: They certainly look at economic impacts, as their statutory authority says, but they also acknowledge that this project is getting a thorough separate review at the minister's direction by the YUB, and therefore they're satisfied that it will not have any adverse effects on ratepayers given the thorough review that it will receive.

Q. Okay. Now, on page 116 of my book, the draft screening report lists terms and conditions related to its recommendation. What additional costs are associated with each of these eight terms and conditions?

A. MR. OSLER: I think Mr. Morrison in his opening comments said that with the exception of the recommendation respect to underground transmission that these recommendations do not make any -- we're not aware of any material differences or changes to the cost estimates in this project because these type of things are incorporated in the current package.

The one exception I've noted was noted in Mr. Morrison's opening comments. And the comment was also made at that time that YEC would be reviewing and seeking to get revision to that one recommendation.

Q. Okay. Let's leave aside that recommendation for a moment. But all of the rest of these were things that would have been done anyway and are incorporated in your cost estimates?

A. MR. MORRISON: That's correct.

Q. Okay. Well, let's deal with the outlier. What's that going to cost to comply?

A. MR. MORRISON: Well, we're working on the estimate, but it will be significant. It could be as much as a million dollars.

Q. A million dollars?
A. MR. MORRISON: It could be. Which is why we're hoping that we can on a common sense basis convince YESAB that that's an issue that will add to the cost of the project. And really what they're talking about is an esthetics issue, not a material issue related to the operation of the plant.
Q. Okay. Now, with respect to the YEC LNG presentation at the YESAB public meeting of December 11, 2013, at page 142, YEC refers to all of the diesel generation on the Yukon grid as backup generation.
A. MR. MORRISON: That's correct.
Q. Can you confirm that the existing WD1 and WD2 diesel generators are used for backup and/or emergencies only and that there are no pending industrial loads that are driving the proposed project?
A. MR. MORRISON: That's correct.
Q. Okay. And can you confirm that the proposed LNG fuel generators will only be used for backup and/or emergency purposes?
A. MR. MORRISON: Mr. Chairman, I just want to be very clear. They are built -- they are installed to provide and meet the requirements of our capacity calculations. They will be used to back up the system in emergencies. They will be used from time to time if we have a drought situation on

the system, which is a short-term situation. If we lose water levels in one of our systems for a summer, we would use the LNG and the diesels to provide the additional load required. And, obviously, on an annual basis, as we've looked at here, they'll provide small amounts of incremental diesel required to meet the system's requirements where there's a deficit on hydro.

A. MR. OSLER: One thing to be clear about is that the Mirrlees at the moment are very low in the stacking order, as you can see from their history of how much they've been used. They are simply -- they are to be emergency backup, can contrast the new gas engines in order to secure the fuel cost savings, would be used as a first-on operation. So there's a quite a significant difference in how they would operate.

But, essentially, in summary, gas engines are used like the diesel engines are for the same purposes.

Q. How did YEC determine the frequency of generation sources to meet the demand?

A. MR. CAMPBELL: Well, I can certainly discuss how we dispatch our thermal generation, and that's based -- it's an economic dispatch based on the cost of fuel which varies depending on where they're located, and the maintenance costs associated with those units.

So there is a stacking order that's an

economic basis. So our most cost-effective units are run first, and our least cost-effective units are run last. Okay.

Q. Now, I take it the proposed LNG fuel generators will have a lower revenue requirement than leaving the existing diesel generators in place.

A. MR. OSLER: In the sense that they have a lower cost as shown in Table 4-3, they would, therefore, have a lower impact on the revenue requirement, if that's what you're asking.

Q. Would they be going up in the stacking order then?

A. MR. OSLER: They would be the lowest cost thermal generators on the stacking order. Before them would come the wind and the hydro generators. They are always used to the extent that they have energy available subject to some storage rules for hydro.

Q. What difficulties has YEC specifically run into when the WD1 and WD2 generators were not available for some reason?

A. MR. MORRISON: Well, we have to turn other units on. We have to get -- we have to find a way to get them on if we need them. Even when they're on, they're difficult to keep on.

Q. Okay. And that is because they're at the end of their life; is that what you're --

A. MR. MORRISON: That's because they break.

They -- they almost -- you almost need an oil truck -- lube oil truck sitting beside them pumping oil into them. They leak oil like crazy. They spew oil everywhere. It's because seals and things aren't tight anymore. Parts are worn, and replacements are difficult, if not impossible, to get.

A. MR. OSLER: Just to be very clear. When you're talking about reliability, the corporation has not found that these engines to date have failed to meet the need for reliability. If they had, they'd have a serious problem because they would have an unreliable system. So they're talking about the issue of they have reached their end of life. If they started to have problems today after their end of life, then the corporation would be very naturally concerned about it not having met its obligations to its ratepayers.

Q. What about the proposition that because they're only used for backup and emergency purposes, that YEC could simply let this equipment break down before replacing it?

A. MR. MORRISON: Well, I wouldn't want to be the guy that would have to face the ratepayers of this territory when -- and the citizens of this territory when it broke down at 40 below and I did need it.

And I don't know when it's going to break down, but I want to tell you that when we lost the Aishihik line a few years ago back in 2006, that was an extreme

condition, and I think everybody has to understand that losing a line doesn't mean you just lose the line. Losing the access to generation on a system that is balanced every day, and every hour of every day the operation of the system is balanced, it's balanced by the system operators who balance load and the amount of generation and the location of generation that's required to keep the system in that balance.

When we lost the transmission line from Aishihik in 2006, we not only lost Aishihik, we lost all of the hydro units in Whitehorse for a period of time and some of the diesel because when that load that was being carried by that system came looking for a home, it knocked the entire system out because it's 35 -- it was at that time 30 megawatts of load that couldn't be handled by the Whitehorse generating station.

So it takes time and there is consequential issues that you have to deal with. The engines cannot be just barely okay to operate. They have to be in tiptop condition when they're required because if they're not in tiptop condition, then our efforts are turned towards trying to fix engines that are not operating at 100 percent when we need them to operate at 100 percent. And instead of getting people's power back on, we're fixing broken-down engines. And, quite frankly, I, as the CEO of this organization, am

not prepared to take that chance any longer.

Q. Going back to the discussion we had about what happens when one or both break down now, indicated that basically you have to look for other sources in the system, why would that not occur in the event of a complete breakdown, let's say, as far as replacement?

A. MR. MORRISON: Because there are not sufficient other sources on the system to meet the load requirements that you'd have to service.

Q. Okay. How many hours of use has each of these two Mirrlees had since it was last refurbished approximately?

A. MR. MORRISON: I can't tell you, sir.

Q. When YEC made the decision to retire these units internally, was that based on an analysis by mechanical engineer?

A. MR. MORRISON: Yes, that would have been based on an analysis by mechanical engineers, electrical engineers, our senior mechanics. All of those people within the organization would have been involved in those decisions.

Q. And were those opinions consolidated into a report?

A. MR. MORRISON: No, sir.

Q. How did you collect and disseminate and digest that information?

A. MR. MORRISON: Well, it's digested and gathered over a period of time. And at different points in

time, we look at the assessment on the engines and, you know, decisions are made internally from operating information that, as I've indicated to you, it isn't just the cost of refurbishment; it's also the ability to get parts and to get them in a timely manner and to be able to rely on the fact that we can get the parts. And, over time, that has deteriorated to a point where nobody's prepared to support continuing doing this.

Q. But I would assume that at some point in time, there was one consolidated report that recommended this?

A. MR. MORRISON: No, sir, there was not.

Q. So when it was determined, it was determined simply in a meeting of management; is that what you're saying?

A. MR. MORRISON: Well, it was determined in several meetings over a period of time, yes.

Q. And there was no report that was issued to management?

A. MR. MORRISON: No, sir. There was no one single consolidated report issued to management, no.

Q. Okay. It's kind of a big decision --

A. MR. MORRISON: Well, it's a very big decision but, you know, management decisions take the form of a whole lot of different sources of information and they don't necessarily always take the form of a written engineer's report.

And in this case we have a lot of experience

over a lot of years with these engines, and the people that know these engines the best and work with them every day, the mechanics, have a significant amount of input into decisions that are made as well as the electrical and mechanical engineers who also support this system. So --

Q. I don't doubt it, but presumably at some point in time, you'd want to transcribe those opinions into a report, would you not?

A. MR. MORRISON: You asked me if I had a consolidated report. I said no.

Q. No. What reports do you have?

A. MR. MORRISON: Mr. Janigan, I have what I indicated to you. Over time, we don't necessarily need to do a report on each of these engines. We have -- we have operating history, we have mechanical work that's been done, work orders, we have the experience and the knowledge of the operators. And all of that, when it comes together and you look at it, is a very compelling case.

Q. I've lost track of what should be going in and what is already in and what should be going in. I believe the YESAB public meeting --

THE CHAIR: I guess I can interrupt here because I don't think there's anything that has to go in as exhibits because they've all been dealt with in one form or another.

MR. JANIGAN: Okay. I think that's correct based on the fact that the excerpts from each of these different reports were put to the witnesses, and the witnesses responded so that -- they're given -- there's a context for their responses given by the excerpts that have been read to the witnesses before.

THE CHAIR: And that's how I took, and I believe that's how YECL had viewed it as well.

MR. LANDRY: Yes. And just for the record, as Mr. Osler I think said, a couple of the documents are actually in evidence --

THE CHAIR: Right.

MR. LANDRY: -- and I was making sure that when the reference was done that actually that exhibit reference is on the record, so I don't think there's any need to --

THE CHAIR: And there was one place where I came back just before the break at lunch to just confirm that there was an item that was on the record already.

MR. JANIGAN: Okay. I think that's fine, then.

Let me just take one more quick look at my notes here, but I think those are all my questions.

Oh, I have one question here.

Q. Does YEC have an option of asking any larger customers

to switch to their owner generators when the system demand is high?

A. MR. MORRISON: We don't -- a couple of things, Mr. Chair. We don't have any -- anybody on an interruptible rate. So we don't have that just as a basis.

When service is interrupted and the Capstone Mine wishes to operate, it has to turn its diesels on. Its diesels don't supply all of the load requirement that they have, but it can do the basics. But that's the only customer that we have that has that.

Q. And what sort of percentage of the load is that?

A. MR. MORRISON: I couldn't tell you, sir.

Q. Any help from anyone else there?

A. MR. OSLER: Not off the top of my head. I mean, the Capstone load is 30 -- well, it's in -- the assumptions are in Appendix C as to what -- the Minto load is assumed to be 34.6 gigawatt hours in 2013, 38 gigawatt hours in 2014, 40 in 2015, and 43.5 for the years 2016 to '22. That's on page C-1 of the application.

A. MR. MORRISON: What I can't tell you is what they have in terms of capacity and what works. That's what I can't tell you.

A. MR. OSLER: To be very clear, that load includes losses to supply them. So their actual purchases from YEC would be somewhat less because it would be what they

pick up at the mine site.

A. MR. CAMPBELL: Sir, what I can tell you, when they originally went into service, obviously they started out self generating; and I believe they had 4 1/2 megawatts. 3 by 1.5 megawatt units.

I believe those may still be in place. Their loads have grown since that time and they would no longer be able to achieve their full mill production, but they could -- they could certainly do a controlled shutdown of their mill processing facilities and they may be able to operate at a reduced throughput through the mill.

A. MR. OSLER: And just for the record, Yukon Energy's capacity planning criteria is presented in its 2006 resource plan and reviewed by the Board at that time.

As a certain -- as two tests that I'm going to be speaking at a high level. One of them is the loss of load probability test. The other one is the N minus 1 simple test.

The N minus 1 test is the one that's been used in this application. It only applies to non-industrial loads. It's not affected at all by industrial loads in terms of capacity requirement.

And what we've found in 2006 and updated in the 2011 resource plan is that the loss of load test wouldn't probably come into play as being relevant until you had mine

loads of a certain magnitude. And I think the 2011 resource plan says the magnitude of the mine load would probably have to be in the order of 12 to 14 megawatts. I think it was more like 7 or so in the 2006 resource plan.

A short point being, unless we have more mine loads than Minto and Alexco together, the capacity tests that are driving the need for this project are entirely determined by the non-industrial peak load; which means that Minto essentially had better look after its emergency conditions in the event that the shut -- that a emergency on the system.

MR. JANIGAN: Thank you.

Mr. Chair, those are all my questions. Thank you for the panel for their patience.

THE CHAIR: Thank you, Mr. Janigan. I'm going to propose that we take our break now. It's a little bit early, but we are going to be recessing today at 4:30 as opposed to the normal 5:00. And then that will allow Mr. Austin to get set up and we can move on from there, and then he won't be interrupted during his questioning.

So if there's no disagreement with that, that's what I would propose we go ahead. And we'll recess now 'til 3:00. Sorry. Take a break until 3:00.

(ADJOURNMENT).

THE CHAIR: Please be seated.

So, Mr. Austin, I'll turn it over to you

whenever you're ready to proceed.
MR. AUSTIN: I'm ready to proceed right now.
THE CHAIR: Fair enough.
Just before -- is there any returns or preliminary matters?
MR. LANDRY: Unfortunately, I think there's one left on the record, and we still don't have that.
THE CHAIR: That's fine.
MR. LANDRY: We hopefully will have it by first thing tomorrow morning.
THE CHAIR: Thank you.
Sorry, Mr. Austin. I didn't mean to interrupt you.
MR. AUSTIN: That's fine.
MR. AUSTIN CROSS-EXAMINES THE PANEL:
Q. Panel, if you've already forgotten -- which you probably have -- my name is David Austin. I have at counsel table John Maissan and Anne Middler. They will assist me from time to time, so, if things get slowed down a little bit if I have to consult with them, I appreciate your indulgence.
So, panel, the first question I have for you is about the natural gas engines, the Jenbacher 620s. Have I got it right that the natural gas engines that you have purchased or about to purchase are the Jenbacher 620s?
A. MR. MORRISON: Yes. Hang on a second.

A. MR. CAMPBELL: I believe they're actually a 624, they're a 24-cylinder, not the 20-cylinder model.

Q. Okay. 624. So we're dealing with the Jenbacher 624s. Can these Jenbacher 624s be run on anything other than natural gas?

A. MR. CAMPBELL: The one that we have purchased, not without modifications. They are certainly designed to run on a variety of fuels including biofuel, waste gas. The ones that we have purchased are set up to run natural gas.

Q. So essentially what you're telling me, they're a gas-only engine?

A. MR. CAMPBELL: They're certainly a gaseous fuel engine.

Q. Okay. Well, let's put it this way. If you wanted to run them on a liquid fuel like diesel, would it be fair to say that you'd have to essentially completely tear them apart?

A. MR. CAMPBELL: We don't know the answer to that. That's not an area that we've looked at. We know that they have successfully run on a variety of other gaseous fuels.

Q. Okay. So for the purposes of your analysis in terms of purchasing engines over a 40-year life, your expectation is that they will run on natural gas, and you didn't look at whether they could ever be converted to run on a liquid fuel

such as diesel.

A. MR. CAMPBELL: Subject to check, that's correct. I can check with our engineers that were involved in that, but that was my understanding. I don't believe this model is available to run on diesel.

A. MR. OSLER: Essentially the application presumes these are gas-only engines for the purpose of comparison with diesel as distinct from the dual fuel engines. So I don't think, subject to Mr. Campbell's checking, I don't think there's much debate about the nature of what the project is proposing.

Q. Now, in evidence this morning I heard that this project is all about capacity. Did I hear that correctly?

A. MR. MORRISON: That's correct.

Q. But for the purposes of your business plan that goes out to 2018, your estimated savings are based on essentially energy production in a dry period. Is that correct?

A. MR. MORRISON: Not quite, but I think mostly correct.

As we indicated earlier, Mr. Chair, the capacity is the primary driver. That's the underlying driver in the project. In addition to satisfying our capacity requirements, the project also allows us to meet the needs of incremental diesel generation that we have been experiencing over the last few winters and will experience at higher rates

over the next several years as we go forward.

Q. Just to be clear, though, for the purposes of dry periods, you use these -- your expectation is that you will use these engines to produce energy. Is that correct?

A. MR. MORRISON: If we have a situation where we have a drought period and we do not have additional renewables on the system, that is fully our expectation that, on a short-term basis, getting us through a dry period we would use these units to offset our deficit on hydro.

Q. In terms of the period of record for your critical water sequence or your drought, how long is that?

A. MR. MORRISON: Sorry, I'm not sure I understand the question.

Q. For the purposes of your planning and estimating your length of your drought, what period do you use? How long? Is it one year, two years, three years?

A. MR. OSLER: Well, I mean, the evidence in the application is at page C-6, and it provides a review of the 31 years and apply of water records and applies them to forecast for 2016 base case and 2018 for scenario A. So you can see the distribution that that provides for different years and different loads different amounts of water.

To give an example, the forecast default diesel requirement for 2016 is 22.9 gigawatt hours without Alexco or 33 gigawatt hours with Alexco. In roughly 50

percent of those water years, you'd be needing at least 52 percent. To be exact, you'd need 15 gigawatt hours or more of diesel without Alexco or 25.9 with Alexco. Some of those years you could need double that. You'd need up to 100 or more.

If you were focusing on a sequence of years that tend to lead to a very severe drought condition, you'd be looking at the late ' 90s as you can see from the left-hand side of that table, and it's a series of four or five years in a string where low water conditions that didn't really register on people here because at the tame the Faro mine closed. If the Faro mine had been open, we'd all have this prominently in our memory banks.

Q. How long was the string?

A. MR. OSLER: It looks -- if you look at the left-hand side of the page; 1995, with 2016 base case would have required about 35 gigawatt hours; '96, about 63; and '97 about 68 or 9; '98 about 76; '99, 101; 2052 -- and then it starts to back down to less than 25 gigawatt hours. So it's six, seven years. I wasn't counting, but -- that would be the Yukon's history's evidence as to a string of years low water.

Q. And when did YEC determine that it had a capacity problem?

A. MR. MORRISON: Well, Mr. Osler, I'm sure, will

remind me in terms of the first time we had a discussion with this Board in recent years about capacity planning, but I think it goes back to as early as 2006.

A. MR. OSLER: In the 2005-6 resource plan, focused on the need to have a capacity planning criteria that would work for this grid, and pointed out that with the end-of-life of the Mirrlees, we had a capacity planning problem that had to be addressed.

It doesn't mean that Yukon Energy didn't think about capacity planning issues well before that. I'm not suggesting that. I'm just saying in the context of current hearings and discussion, there was a front-and-centre issue in that particular resource plan and the hearing that YUB held from that.

Yukon Energy updates their forecasts fairly frequently, so this particular forecast that you see here has many precursors on Table C-4. I mean, during the last GRA, we would have seen a previous version of this, and it would have showed capacity shortfalls in various years. So it's not a brand-new idea that there would be a capacity shortfall emerging when these units start to be, you know, end-of-life again.

Q. Could you repeat the last part that question? I didn't understand -- answer -- I didn't understand that very well.

A. MR. OSLER: It's not a new idea that there

would be a capacity shortfall emerging about the time you see here.

I think -- we can check, but we had earlier forecast for the 2011 resource plan. We can check what dates they showed these capacity shortfalls emerging, but I wouldn't be at all surprised if they're roughly about the same time because we had exactly the same dates for retirement of various units. And the load forecast, if anything, is a little bit higher now than it was then for non-industrial loads, but I wouldn't have thought it would make that much difference.

Q. So in about 2006, you recognize that you would have a capacity shortfall problem emerging about now.

A. MR. OSLER: No, we actually knew we had a capacity shortfall problem that existed then. And the issue of refurbishing Mirrlees units was proposed as a game plan to deal with that problem. Otherwise they would have had to retire 14 megawatts, and the system would have been short of capacity then.

Q. But for the purpose of my question, can you just give me a clear answer as to when was the earliest date that you anticipated the capacity shortfall that you're trying to address now?

A. MR. OSLER: We'll get a check as to what the earlier plan showed and see whether or not the answer

I've given you needs to be modified. I'm thinking that it's probably been known for several years, but we'll check it.

Q. Is it several years or is it starting in 2006?

A. MR. OSLER: We'll check it for you.

Q. In this morning's testimony, and you can correct me if I get this wrong, it was my understanding -- or it is my understanding that for the purposes of your business plan, you're projecting about -- and these are very rough numbers -- about 9 million in savings by using natural gas driven engines, and that approximately covers -- with the emphasis on approximately -- about 9 million in additional costs that would be incurred for LNG infrastructure not including the capital cost of the natural gas engines.

A. MR. OSLER: I don't think that would reflect what people were trying to say this morning. So let me summarize it.

Based on the update Exhibit B-13, Table 1 on page A-5, I'll go down the table. The capital costs for new diesel versus LNG are given at the top of the page. The new diesel alternative totals to $32.7 million. The LNG alternative, including engines and everything else, $42 million and that includes 1.1 million of contingency on the third engine which was not a forecast; it's just a contingency for the purpose of this analysis. The difference is 9.3 million in capital costs, all inclusive.

The annual capital costs allocation, given a 40-year amortization, are shown in the table. The difference between LNG and new diesel is shown. The sum of those numbers for the four years is 2.7 million difference.

So the extra capital cost impact on ratepayers in those four years would be $2.7 million for LNG, more than new diesel.

The fuel cost savings, as estimated in the table, is shown below. Over the time period, the same four years, they total $11.9 million. The overall savings in the four years given amortization is $11.9 minus 2.7 or 9.2 million.

I think Mr. Morrison also said that the actual fuel cost savings during that time period of 11.9 were more than enough to cover off the full capital cost difference of 9.3 million.

Q. Yes, but the full capital cost difference of 9.3 million does not include the remaining capital cost with respect to the natural gas engines because the total cost of the project is about 42 million as I think you've justly told me. You've told me that I'm getting savings of roughly 9 million because I'm using natural gas. So by my quick math, that means I have about another $33 million that has to be recovered over the next 40 years; is that correct?

A. MR. OSLER: I don't understand at all what

you're saying, so I can't...

In the four years if you had new diesel versus project as proposed, you would have paid off, you know, four divided by 40 of the capital costs for each one of the alternatives. So you'd still have a bunch of capital cost left to be recovered through depreciation, etcetera.

If that's your point, the $9.2 million saved over this time period in fuel cost savings compared to the capital costs that are charged during that time period still has to apply against the balance of the capital costs for the rest of the time period, if that's your point.

But the point that we were making is that, one way or the other, if we didn't have this project, ratepayers would be paying $11.9 million more in fuel during this time period. And by having this project, they are saved from paying that during this time period, and that difference, when pocketed, is enough to have paid off completely the capital cost difference between the two projects.

Q. All I'm doing is paying off the capital cost difference between the two projects with the fuel cost savings in the next four years; is that correct?

A. MR. OSLER: That's what I'm understanding.

A. MR. MORRISON: Let me try this maybe my way.

One way or another, we have to spend the amount of money as the base case here is -- and I don't have

my figures, but the diesel is $32 million -- $32.7 million. And so we have to spend that money. In the four year -- and in comparison to that, if we do LNG, we're spending 41; right, 42. So $10 million -- we're basically spending $10 million, $9 million more.

So the argument here in this table simply is this: Ratepayers are better off because in four years we've paid off that $9 million. We still have to pay for either diesel or LNG, but now we're even. And all of the savings going forward go to the benefit of the ratepayer.

But the point that was being made earlier is it only takes four years to get rid of the delta in the capital cost between LNG and new diesel. That's simply what we're saying.

A. MR. OSLER: And now that I get -- there's still the balance of the capital cost that would have been incurred with diesel to be paid off over the remaining life, that's true.

Q. And there's also the balance of the capital cost to be paid off with respect to the natural gas engines over the remaining life?

A. MR. OSLER: Either way, but it's no penalty for having chosen gas versus diesel; that's the point.

A. MR. MORRISON: There's a benefit for choosing natural gas in that as you go forward and if the engines are

operated, so let's go to year six. Well, after year four, if there's diesel or gas used on the margin in year five and year six and year ten and year twenty because you're still using small increments of thermal requirement for the system, it's much better off for ratepayers the longer you use the small increments of additional requirement.

Q. That also assumes, does it not, that the price of natural gas is lower than diesel in years 4 through 40 because if the price of natural gas is higher than diesel in years 4 through 40, it will actually start to lose money on the investment in natural gas engines. Is that not correct?

A. MR. MORRISON: Sure, but, Mr. Chair, we have seen nothing that tells us that.

Q. But that's a risk.

A. MR. OSLER: We've discussed it in the application, yes.

Q. For the purposes of people in this room and maybe people in the panel, could you please explain the difference between energy and capacity?

A. MR. OSLER: For the purposes of this discussion, it goes to the planning and operation of electrical grid. And as a utility responsible for the grid, Yukon Energy has to plan for two things. It has to plan to have a capability or a capacity to supply energy at any moment that it may be required. So it has to have a peak

capacity capability to do that, which means it has to have enough generation, transmission, etcetera, to meet a peak winter load. And on top of that, the requirement of the capacity planning criteria is that it be able to meet that peak winter load taking into account that its hydro generation is somewhat constrained during that time period.

At Whitehorse, the peak capability that you can firmly rely upon in wintertime from Whitehorse is not 40 megawatts, it's more like 24, I believe.

So we have to take that into account. And we also have to take into account the so called N minus 1 event, the worst case event that could lose capability, which is the loss of the Aishihik line. So we cannot rely upon the 38 megawatts at Aishihik for that purpose.

In contrast, the utility also has to plan for the most cost effective way to generate the energy required during the whole year and future years. Energy is measured and we usually talk about it here in millions of kilowatt hours or gigawatt hours, but it's a measurement of how much we actually generate over a period of time and it's often discussed in terms of the year in the context of this discussion, but it could be discussed in terms of time periods or seasons.

And at a very simple level in planning for those two things, capacity and energy, you'd like to spend as

little capital as possible to meet your peak requirement because some of that capacity is not run very often. So you don't want to have to spend a lot of money on it.

But for the energy that you're generating all the time, or a lot of the time, you'd like to find the lowest way to generate energy which could be a fuel, or it could be a very capital-intensive hydro unit that is operated efficiently all the time. So they're quite different issues in terms of planning and in terms of costing, and that's why we talk about them that way.

This project is being put forward solely to meet a capacity requirement, and it is not expected that the units would, on average, be operated anywhere like 50 percent, 80 percent. If this was a mine that was putting in gas engines, it would be expecting to operate these units very high level of efficiency, but these units are expected to be used for capacity purposes and not to be operated a great deal.

Q. Would the participants in the January 18th, 2012 LNG workshop know the difference between energy and capacity?

A. MR. MORRISON: Certainly some of them would, yes.

Q. Would it be fair to say most of them wouldn't?

A. MR. MORRISON: No, I don't think I'd say that. I don't know, but I wouldn't agree to that. There are a

number of people there who would very well know, including people in this room.

A. MR. OSLER: But I don't think the focus of the discussion was capacity versus energy. I think, generally speaking, the participants were talking LNG as an energy option more than a capacity option. It was noted that it provides firm capacity, but the conversation, as I recall it, was much more in the context of using it to displace larger volumes than we're talking about here, of diesel.

And certainly this project, as a capacity-only project, was not on the books or being talked about by Yukon Energy, to the best of my knowledge, at the time. It was about six months later that it started to be considered as a possibility.

Q. And this is another question that is a follow-up from the cross-examination of earlier today. There was the discussion with respect to the loss of the transmission line from Aishihik in 2006, and I certainly need some assistance here in understanding; what was actually lost? Was it the actual transmission line that comes from, presumably, the substation at Aishihik, or was it a loss or a failure of a cable within the generating system on the generating side of the transformer at Aishihik?

A. MR. MORRISON: The latter, sir.

Q. So it was a cable failure within the generating station.

A. MR. MORRISON: That's correct.

Q. And has that generating station cable been twinned so that if it fails -- one cable fails, there's backup for it now?

A. MR. MORRISON: That's correct. But, Mr. Chair, that does not in any way change the capacity planning criteria and the criticality of the Aishihik line as our most risk -- the point with the greatest risk in the system. Because the line has the largest winter capacity, at least at that time, on the system, of 38 -- 37 and a half megawatts, that's the critical point of failure is that line.

Now, we don't design capacity planning criteria, and we've had witnesses, and we've certainly had numerous hours of discussion in front of the Board regarding that planning criteria and what it's set out as.

But, you know, when I first started in this business, we used to think it was generation that was our exposure. In fact, it really is, these days, transmission that gives us biggest exposure, largest exposure.

Q. Have you ever lost the transmission line, meaning the line that's on the transmission side of the transformer from Aishihik to Whitehorse?

A. MR. MORRISON: Have we ever had outages, are you saying?

Q. Have you ever lost the line?

A. MR. MORRISON: Are that would be an outage. I -- yes, we've had outages. How many on the Aishihik line? I couldn't tell you. How many on the Faro line? I couldn't tell you. But we certainly have outages.

Q. And just --

A. MR. MORRISON: And, sir, I will point out as well that there are times when we have shut down the line -- not the Aishihik line -- in the last few years, but certainly the Faro line, for forest fires in the area. We had -- I can't remember if it was last summer and the summer before, but we had numerous days where we had lines voluntarily shut down because of fire concerns in the area, and therefore, no ability to use that line to transmit power from the north or from Faro or out to Faro from Whitehorse.

A. MR. OSLER: And just for the record, the conversation we had in 2005, resource plan 2006 didn't make a big deal -- didn't make a big deal of the formalities of the generation station versus the transmission line. It actually envisage the failure going right down into the ground and coming up the elevator. Unfortunately, that's what happened.

But there were options looked at of twinning that line and everything else. It was a very serious consideration given to what it takes to build redundancy into that, and so far it hasn't been cost effective to build twin that line all the way to Whitehorse as is required.

Q. Without being disrespectful or in any way trying to be humourous, do you have forest fires in the middle of winter?

A. MR. MORRISON: I'm not sure what the point of that is.

Q. Well, the point is that you just told me that you can't shut down lines for forest fire risk, and we're talking about a need to meet the peak load in the middle of the winter. If there's a need to meet the peak load in the middle of winter, is forest fire a risk that you have to take into consideration?

A. MR. MORRISON: Well, not to be disrespectful, sir, but the question you asked me was, have we ever lost a line? And that's what I answered, not whether or not I've lost the Aishihik line in the middle of winter.

Q. Well, have you ever lost the Aishihik line in the middle of winter?

A. MR. MORRISON: In my memory, the only one is 2006.

Q. Thank you. In terms of cross-examination, there was reference to the Capstone mine, and it's not clear to me whether that's a firm customer or an interruptible customer. Can you tell me whether it's a firm customer or interruptible customer?

A. Capstone mine is a firm customer.

Q. And there was this afternoon some sort of discussion as

to how big the Capstone mine load is. And does anybody on the panel know how big the load is?

A. MR. MORRISON: Well, I think Mr. Osler gave some numbers. But the problem with the question that your colleague Mr. Janigan was answering -- asking is, we don't know what they have on site in terms of openable units, so we couldn't give him a percentage of how much they can generate of their own load with their own equipment.

Q. Can you give me any idea what the estimated load is in megawatts? Because, again, we seem to be talking a lot about capacity.

A. MR. MORRISON: It's in the neighbourhood of 5 megawatts.

Q. 5 megawatts?

A. MR. OSLER: It's in the neighbourhood, but it doesn't affect the capacity planning criteria, as I explained before the break.

A. MR. CAMPBELL: Yes. Sir, I would point out in our application in Table C-4 in terms of capacity planning. Again, the grid demand numbers that we're using exclude industrial customers. So the forecast demands and the reserve criteria being applied excludes industrial customer demand.

Q. Okay. I think I've got it. So the point there is, if you went to Capstone and said: If there is peak demand or

N minus situation, we will pay you money if you shut down, wouldn't make any difference.

A. MR. CAMPBELL: They will want to run their own generation to meet their own emergency mine requirements. That's what our industrial customers do because we cannot guarantee them the same degree of reliability in terms of reserve capacity planning that we can do for our nonindustrial customers, and that was by order of this tribunal after a long debate in 2006.

A. MR. OSLER: But just to be clear, we proposed -- Yukon Energy proposed capacity planning criteria, the two steps that I explained earlier, and I won't repeat it.

Number two, the industrial load only came into apply when the loss-of-load-probability test required extra capacity. Under the loads the industrial loads have today, they're getting the loss-of-load-probability security that they would get in any event. The N minus 1 test is protecting them as much as anybody else.

It's just if their load got to 13 megawatts or 12 megawatts or 14 megawatts or whatever, we would have to start looking at a loss-of-load-probability test rather than the N minus 1 test as being the dominant one as.

In respect to the question as to how big the Minto load is, it is in the application at page C-8 footnote

number 2. Minto at 4.8 megawatts in 2014 increasing to 5.3 in 2015, shut down in 2022. I think there is other information there if your team is interested in it.

Q. I certainly appreciate all that, but as an alternative to investing money in a new generator because I need capacity, would it do any good to go to Capstone and say: If there's an N minus 1 situation or my peak demand is higher than I forecast, if I pay you some money, would you shut down? Is that an alternative -- or again, it's Mr. Campbell who's trying to help me out here, and I fully appreciate that. Would it do any good, is what I'm trying to ask.

A. MR. CAMPBELL: The experience that Yukon Energy has had to date with all of our industrial customers for the past 23 years is that their on-site mine generation, they have use for their own purposes in the event that we've had a grid blackout that they would not be willing to shut down their mill and try to make some money by selling some power back to the grid.

Q. Have you ever asked them about that?

A. MR. MORRISON: Well, there's two things that we're talking about here, and I'm going to let Mr. Osler jump in.

First of all, we looked at the units that Capstone has on site, and they meet in no way, shape or form the mechanical requirements that we have in order -- in order

to purchase them. So in other words, we don't like the units. They are not reliable. They are in poor working condition, and they would not be capacity issues for us. In addition to that, they're on the grid, and if the grid failed, they may not be available in any event.

Q. Maybe I'm not making myself as clear as I should be. I'm not suggesting for a minute that Capstone should be supplying capacity to Yukon Energy. What I'm saying is I'm trying to find out what Yukon Energy's obligation is to supply capacity to Capstone and is there a business opportunity to go to Capstone and say, "If we've got a problem with capacity, we'll shut you down, and we will pay you for the privilege of being able to shut you down if we need not your capacity Capstone, but YEC's capacity would not go to Capstone, it would go to somebody else."

I realize that's a statement, not a question. But the question is, is there a business opportunity there, and if there is a business opportunity, has it been explored?

A. MR. CAMPBELL: I would --

A. MR. OSLER: Mr. Chairman, there is no business opportunity there. I dealt with Capstone and we tried to put together the initial deal and we did recommend to this Board that Yukon Energy, as part of that deal, purchased those engines that Mr. Morrison has just described to you. They've got a mine to run. They've got lots of

issues.

I have no evidence from my discussions with them years ago that they would entertain this type of a conversation for more than three milliseconds, and now I don't think my colleagues would entertain it for more than half a millisecond because they know what those engines are like.

Mining companies do not have an interest in trying to look after the capacity of the Yukon grid. In fact, they sort of would like to get as low a rates as possible and not get involved in any commitments and they want to run their mine. That's where they get their money, not shut it down.

So no, it's -- we discussed this in 2005/'6. We discussed the various options. We discussed the criteria at length. The Board gave recommendations on it. At the moment, frankly, the company is trying to proceed, move forward based on the decisions made back then rather than revisit them all.

A. MR. MORRISON: Can I have one second?

A. MR. OSLER: Mr. Chairman, my colleagues are just giving me all sorts of other reasons why we shouldn't entertain it and I don't mean -- there are lots of practical reasons.

Alexco is shut down right now. So we want to

phone them and ask them to please start up again if they -- I don't think you'd get very far. We can't rely on that type of thing. It goes on. I mean, we could go on at great length if it's important to everybody, but in simple cases, it's not something worth thinking about.

Q. So your answer is that you've had no discussions with them between 2005, 2006 about this type of issue?

A. MR. OSLER: Correct.

Q. I'd like to move on to the application. This is on page 10, and I'm just trying to get a bit better understanding of the concept of these A-trains. And on page 10, it says: (as read)

> "Significant travel distances and comparatively low density of LNG approximately 60 percent of diesel..."

and it goes on to talk about the double trailer A-trains. And there's reference to 95,000 litre capacity versus the tridem units with a 54,000 litre capacity.

And as I understand it, you're trying to get A-trains permitted for use in British Columbia and Alberta; is that correct?

A. MR. MORRISON: And the Yukon.

Q. And the Yukon.

A. MR. MORRISON: And the Yukon.

Q. You haven't received approval for the Yukon yet?

A. MR. MORRISON: We've received notice from the Yukon highways that they will approve an A train configuration.

Q. In relation to the first part of the sentence about the density of LNG being approximately 60 percent of diesel, would it be fair to say that for every six loads of diesel I would need -- six truckloads of diesel, I would need approximately ten truckloads of LNG to get the same amount of energy?

A. MR. CAMPBELL: Sir, that would be correct if, in fact, the trailers were the same size. They're not. A-trains are larger than conventional B-trains used because the --

Q. Can I stop you right there? What's a B-train? I'm sorry, I just want to get it clear in my mind.

A. MR. CAMPBELL: A B-train is a conventional hauler used today for hauling diesel fuel around the territory, and its governing weight is based on the weight of the fuel. Natural gas only weighs two-thirds the weight. So you can go to a larger trailer because the tare weight is less. So basically the objective in pursuing an A-train and being able to handle or to hold 95,000 litres per train is you get the equivalent BTUs per trainload as you would in a Super B -- in a B-train --

Q. Okay.

A. MR. CAMPBELL: -- full of diesel. So it's a one-to-one comparison.

A. MR. OSLER: For the sake of everyone, we're going to bandy around some terms. So what Mr. Campbell just said is really important is that the weight -- not only does the energy differ, but the weight differs and the thing that really drives what people will permit is how much weight.

We can have A-trains or B-trains, even for LNG, and they might carry the same amount. It's more to do with the tire configuration in the case of them.

So let's not assume that the word A-train or B-train is terribly relevant to the conversation. What's really relevant right now is how much can you move of each fuel, taking into account the difference in their energy density and the difference in their weight? And that's the key point that Mr. Campbell is making.

Q. Thank you. Appreciate that.

Now, in terms of an A-train, meaning an LNG A-train, how much longer and/or how much higher and/or how much wider would it be than a B-train that normally hauls diesel?

A. MR. CAMPBELL: They're about the same length. They're two feet wider. They're 10 feet wide compared to eight feet wide and slightly taller because it's basically a round tank.

Q. Essentially, it's a thermos bottle on wheels?
A. MR. CAMPBELL: Correct.
Q. For the purposes of the application, you're now saying that you would source LNG from Tilbury Island in the Vancouver area; is that correct?
A. MR. MORRISON: That's correct.
Q. And where is Tilbury Island in relation to the Greater Vancouver Metro area?
A. MR. MORRISON: It's in Delta.
Q. And Delta is about as far west as you can go in that area?
A. MR. MORRISON: I don't know. I'd take your word for that if you -- but I don't know if it's as far west as you can go. I don't know that.
Q. Subject to check, would you agree that it's about as far west as you can go?
A. MR. MORRISON: Sure, sure.
Q. So for the purposes of picking up LNG in Tilbury Island, you would have to move it through a good percentage of the densely populated area of Greater Vancouver and the lower Fraser Valley?
A. MR. MORRISON: Mr. Chair, again I don't know the routing off the top of my head. But all I would say is that Northwest Territories Energy Corp is moving LNG from Tilbury to Inuvik today.

Q. But they're using not an A-train, they're using a tridem unit; is that correct?

A. MR. MORRISON: That's correct. And I think as noted earlier, they are part of the team that is looking at the A-trains with us.

Q. Right. And in relation to the tridem units in terms of width, height and length, how much smaller are they than the proposed A-trains?

A. MR. CAMPBELL: I believe they are the same width. I can't recall off the top of my head the length. They are one large tank as opposed to two smaller tanks. That's the way that they're configured. And they're currently designed to haul 65,000 litres per truckload.

A. MR. OSLER: Just to be clear on the record, the application talked about tridems using 54,000 litres. YUB 44 said 64, 65,000 litres because of the information we had. And the most recent material we filed says that NT Energy is securing about 60,000 in practice, just so the record's clear. And that's in the update that was filed.

Q. And in relation to the approval process in British Columbia, whereabouts are you?

A. MR. MORRISON: Well, as of meetings last week with the Highways ministry, who has to permit this configuration, they tell us that, from what they've seen so far, things are very positive, and they've asked for a little

bit more information, but we're not seeing any major difficulties in our route.

Q. And what sort of timeline have they given you for potential approval?

A. MR. MORRISON: I just don't have that in front of me, sir.

Q. Well, you just met with them. Did you --

A. MR. MORRISON: I didn't.

Q. -- prompt them to get any indication of what the timeline is?

A. MR. MORRISON: Well, I didn't just meet with them. We met with them, Yukon Energy. And I don't have that in front of me.

Q. And as I understand it in the application, is it fair to say that YEC is taking the cost risk of fabricating any A train units?

A. MR. OSLER: I think what we've answered in YUB 5 is an outline of a program where YEC is taking -- getting the contractor to do the design work. But I think it's made clear that the actual decision to fabricate would be made after the permitting was clarified, and also, who would end up owning the engine -- the units was clarified. So I don't think that YEC is willy-nilly taking out a fabrication risk until it has some other things clarified. But it did want to get on with the design of

the units so that they could be fabricated on a timely manner.

Q. I understand that, but the actual cost of fabrication -- is that a YEC risk?

A. MR. OSLER: I think the IRs make it clear that it could end up being owned by various people, and not necessarily YEC. Under contracting like NT Energy has, I guess, you could argue that no matter who owns it, if you have a contract with a trucker who owns the material, you'll probably end up carrying the risk of the unit in terms of it's solely for your purpose and you've got a lease for five years or a contract for five years. If that's what you're getting at, they might end up carrying the risk, if you like. But they're not necessarily planning to own it or spend money on fabricating it. I think that point was made clear in the IRs.

Q. I'd just like to follow up that so that I've got it clear in my mind. Let's suppose that you get all your necessary license, permits, approvals, you get a cost estimate of $50,000 -- and that number is just pulled completely out of the air -- for fabrication of A train. It turns out it's $100,000. Who's got the risk for cost overrun in my example of $50,000?

A. MR. OSLER: Well, there's no contracting framework in place at the moment, but that would be an issue

between the fabricator and whoever the heck is going to own it, in terms of their contract.

So the people that YEC has been dealing with have given some estimates before anybody asked them to fabricate it. Whether it was YEC or somebody else, they would have a contract that would answer the question you just asked me.

Others have done this with the tridems. The tridems for Northwest Territories were specifically designed for that, and they didn't run into great issues of the type you're discussing in the process of doing it.

I think the bigger risks are not so much the cost of fabrication; it's just making sure it does all the things you want it to do and that the regulatory framework of governments and everything else, which is evolving, that you're up to speed with it. At the moment, that's been the bigger practical problem for Northwest Territories.

Q. So the answer at this point in time is it's an undefined risk.

A. MR. OSLER: It's an undefined risk that is not expected to have a big impact cost-wise. These units would be amortized over fives years, if they're operated intensively, and if they're operated less intensively, they will be amortized over a longer time period.

Q. I'd like to change subjects now, and I'd like to discuss

the Tilbury LNG facility. Is it fair to say that the Tilbury LNG facility is currently the only LNG facility in Alberta and British Columbia that sells LNG to third parties?

A. MR. OSLER: I'm not sure that's technically correct, but from the point of view of being a practical supply option, it is correct. There may be some ability to pick up LNG from a couple of other sources, but they wouldn't be material for the purpose of this conversation.

Grande Prairie, Ferris, EnCana will start operating very, very soon, but again, I'm not sure we would view them as an option, but they have a material supply capability and they are selling to third parties -- they will be selling to third parties as part of their business plan.

Q. They will be, but currently they're not because they're not in operation.

A. MR. OSLER: They're commissioning right now, yes.

Q. Okay. Now, for the purposes of Tilbury, there was material filed -- and it's Exhibit B-13, and it's the YEC update of March 27th, 2014. And in that update -- and correct me if I'm wrong -- you're planning to purchase the LNG that you think you require from FortisBC. Is that correct?

A. MR. MORRISON: That's correct.

Q. And you're proposing to purchase that LNG pursuant to

what's called Tariff 46. Is that correct?
A. MR. MORRISON: That's correct.
Q. Do you happen to have copies of Tariff 46 available to you?
A. MR. MORRISON: Yes.
Q. The questions I'm going to ask are for the purposes of just trying to probe what sort of contractual relationship that you're going to have with FortisBC, and I'd like to refer you to the definition section of the tariff and, in particular, the definition of "delivery charge." Do you see that?
A. MR. OSLER: Yes.
Q. And the delivery charge consists of an LNG facility charge and an electricity surcharge. Do you see that?
A. MR. OSLER: Yes.
Q. And can you tell me what the LNG facility charge is, just in lay terms?
A. MR. OSLER: Do you mean, what does it cover, or what's the --
Q. What does it cover --
A. MR. OSLER: Okay.
Q. -- because to try and speed this up a bit, when you go further into the definitions, you've got something called "LNG service" -- there's a definition of "LNG service," there's an LNG spot charge, there's a long-term LNG service

and a minimum monthly charge and a short-term LNG service and a spot LNG service.

So what I'm trying to find out is; for the purposes of YEC's LNG needs, what service is it going to be signing up for? What does YEC think it's going to get for this type of service, and how much it thinks it's going to have to pay for this service.

A. MR. OSLER: Right. And if you go to the exhibit that was filed, Exhibit B-13, if you go to page A-3, there is a set of numbers provided as to the delivered cost estimates from Fortis versus Calgary. And the footnote to the Fortis Tilbury estimate for 2015, there is a sentence that says how the number was devised and includes, among other things, the Fortis spot rate is estimated at $5.05 per million Btu, and it's said that that is an approved rate of 4.60 per gigajoule plus inflation, plus conversion to millions of Btu's. And the inflation was assumed at 2 percent a year. These rates getting inflated, according to our understanding of this schedule, as of January 1 of each year, and the rate was formally -- that's in the schedule -- is formally a 2013 rate.

Q. I appreciate that, but what I'm trying to get at is; what service or what level of service is YEC expecting to sign up for?

A. MR. OSLER: I think I just told you, sir.

That rated is based on what is called in this rate schedule the spot rate.

Q. So the spot rate.

A. MR. OSLER: Right.

Q. Do you know what the terms and conditions are for the spot rate? Is it is assured? If you phone them up and say, I need LNG Fortis at Tilbury Island, will you get it?

A. MR. OSLER: It is exactly what the terminology suggests. It is not a contract demand rate. It is not something you contract at a minimum per year or longer. It is a rate that is available as long as there's supply available. So that's why Mr. Morrison has talked to Fortis and why NT Energy talks to Fortis to find out whether there's a need to go beyond the spot rate at this time for the coming winter.

Mr. Morrison can elaborate on that, but the terms and conditions of that rate are as the terminology suggests; not a contract demand rate.

Q. Could you please explain what a contract demand rate is and what level of assurance that, if you're on the spot rate versus the short-term rate versus the long term rate, that you will get the product that you need in terms of this rate schedule 46, not what somebody in the telephone tells you?

A. MR. MORRISON: Sorry. So, Mr. Chair, I'll tell you at a pretty high level, I have not read this rate

schedule, and I'm not sure I'm capable of reading something that dense.

But the spot rate essentially is, we can go to the Fortis facility under arrangement with Fortis, pick up a load, two loads, three loads, ten loads. We can show up every day, we cannot show up for a week, and we can buy fuel from them at a published rate. And that published rate is a rate that is fixed and set by order in -- well, the BCUC was directed by Order in Council to set this rate. They have now set this rate tariff schedule for gas -- for fuel from the Fortis facility. And I don't know if it applies to other facilities that may get built in the province or not.

In addition to setting the rate, BCUC was also directed to include in rate base going forward all of the costs that Fortis will incur in expanding this facility. And I can't tell you the numbers off the top of my head, so maybe Mr. Campbell will, but it's going from what to what --

A. MR. OSLER: 6,000 gigajoules a day to over 30,000 gigajoules a day, and we can translate that, if needed, into other units.

A. MR. MORRISON: But at the same site. So that's all been taken care of. They've broken ground. They're starting, and that's 2016.

We will start on a spot rate, as has NT Energy started on the spot rate. The spot rate does not give us any

assurance, but they have about 60 percent of their capacity at Tilbury unused today. Our requirements are very, very small compared to the availability of LNG at Tilbury.

Q. Can I just interrupt there. Tilbury, as expanded, or Tilbury, as it exists today?

A. MR. MORRISON: As it exists today, sir.

The amount of gas that we may use in terms of going into this winter 2014-2015 doesn't look to be very significant and, therefore, we don't have big -- large requirements that would push us out of the Tilbury plant.

Now, going forward, we will not stay on the spot rate. The spot rate is a very attractive rate in comparison to the prices we were paying before, but we are also in the middle of receiving from FortisBC some proposals that would move us to a contractual rate.

The contractual rate -- and these are my terms, so if they're not quite correct as to whatever terms in this published rate schedule, forgive me. The contractual rate will set out whether we go on an annual yearly rate, we go on a longer term than that, and what the terms and conditions of the supply are, but it will guarantee a supply for us.

Now, I don't want to rush into that. First of all, they don't have -- they don't have enough options for us yet. They are giving us some options. They're giving us

some calculations based on the load profiles that we've given them. And we'll work through that, but suffice it to say that we certainly have the opportunity right now to have a significant amount of supply available to us.

A. MR. OSLER: But I would just -- there's two or three other considerations that are given in the update including the discussions that Yukon Energy's having with others such as AltaGas and Ferus.

So before one -- if one had to nail down a contract, as Mr. Morrison said, he could do it tomorrow morning, but it's not deemed to be prudent at the moment given some of the options and discussions that are going on and there may be opportunities to get lower cost sources supply even closer to Yukon.

The volumes that we're talking about are all on the first page of the update B-13. Current Fortis operating capacity is, as I just said, 6,000 gigajoules a day or translated about 216 cubic metres a day or about 65,000 U.S. gallons a day because some people measure everything that way.

Our requirement forecast forward for the year coming up, winter 2014, 2015, particularly '15, we're talking about maybe 15 cubic metres a day with a peak month use of 44 cubic metres a day. So that's what is meant by their capability relative to our requirement.

And their capacity is noted in the next paragraph, next bullet. They're talking -- they are allowed to and proceeding to expand to about 30,000 gigajoules a day or 1300 cubic metres a day presumably in 2016.

But I repeat, they are not the only party that Yukon Energy is talking to either, so...

Q. But would it be fair to say that for the purposes of the spot rate, there is no such thing as reliability of supply?

A. MR. MORRISON: There's only reliability in the sense that they have far more supply than they have customers.

Q. Let's keep going with Schedule 46, and I'd like to refer you to conditions of LNG service, and this is paragraph 3. It says: (as read)

> "3.1. Availability of LNG Service. FortisBC will only provide LNG service to a customer if adequate capacity exists on Fortis' energy system; (b) there is available LNG capacity that is not already subject to contract demand under LNG agreements for long term LNG service or short-term LNG service; and the customer has entered into a LNG agreement."

So would that confirm what I've just said, that there is no

contractual reliability of supply if you're on the spot rate?

A. MR. OSLER: Well, the statement actually applies to availability of LNG service, period. I mean, most of these types of detailed documents do not make the supplier very vulnerable if they have a reason for interruption because, in this case, the FortisBC Energy system capability for some reason became inadequate. That would be a matter for their regulator to discuss, but even when you have a contract demand, there are certain conditions that give the supplier some rights.

So I'm not sure that that particular provision 3.1 even gets close to discussing spot versus contract demand.

Q. Did you ever enter into a contract with Shell for the supply of LNG from the Jumping Pound facility?

A. MR. MORRISON: Yes, we did.

Q. And in terms of the Shell contract, just to sort of get some context for what goes on in the industry, did Shell have similar type conditions of LNG supply?

A. MR. OSLER: They had provisions in the detailed provisions of the contract that if they had an interruption, they had complete discretion as to how they dealt with it in terms of priorities to different people in the legal sense of the word.

Q. And would it be fair to say that you would expect the

same type of terms and conditions if you entered into a contract for LNG with Ferus and/or AltaGas?

A. MR. OSLER: I think you will find that these contracts will tend to follow some of those key provisions.

Q. For the purposes of supply of diesel generation -- diesel fuel, do you see similar terms and conditions in your diesel supply contract?

A. MR. MORRISON: I couldn't tell you.

A. MR. OSLER: I think the difference in the diesel market versus the LNG market is such that it's a radically different situation in terms of the ability to pick up supply elsewhere.

The ultimate point is, does the person who's committing to supply you, what level of liability do they have if they don't supply you? The practical point is can you get some diesel from somewhere else very easily?

And I think we all know that this market is totally different than diesel at this stage in development. So it's not so much do you have a contract with Shell or Fortis or somebody else, but do you have some options? And at the moment, you've started your questions by pointing out that Fortis is the only party supplying LNG and material volumes to third parties right today and there's a few more coming on. But we'll all feel a lot better when there's

several of them in B.C. and Alberta supplying LNG and mutually supporting each other in the case of problems.

Q. So would it be fair to say that the diesel supply market is what's called a liquid market, no pun intended, and the LNG supply market is an illiquid market, no pun intended?

A. MR. OSLER: I think it's fair to say that there are certain issues with the natural gas LNG market that limit your options if you have a problem from the supplier you pick up compared to the diesel market.

Q. And for the purposes of when Fortis's expansion comes into being, 2016 is used as the reference date. What time in 2016 is Fortis expected to bring its expanded LNG facility into operation?

A. MR. MORRISON: Mr. Chair, I don't know what time in 2016, but our requirements by 2016 aren't sufficient to us be concerned about needing the expanded plant size. We can still draw supply from the existing plant.

Q. As long as nobody else enters into a short-term or a long-term contract between now and the time that you need LNG; is that correct?

A. MR. MORRISON: Or we enter into one.

Q. Right. And what's the difference in cost between the spot LNG rate and, say, for example, a short-term rate or a long-term rate?

A. MR. OSLER: Well, right now looking at rate

schedule 46, they list them, and there is essentially a slight discount for going to a contract demand rate. There isn't a distinction that we can notice between short and long term at the moment, but there will be when they go to an expansion.

So the contract schedule lists out rates not just for today but the rates that would apply when they get to a certain level of expansion. I think it lays it out in two or three stages.

So you can read the schedule and you can see the rates and you can read the clause that says they will be inflated by inflation each year and the electricity portion of the rate will be adjusted based on B.C. Hydro's actual rates and their actual usage.

The key thing that you don't know from reading that is exactly what options you might have under a contract demand to meet YEC's particular load requirements and that's what Fortis is busy examining to make some propositions to YECL.

Q. Perhaps while we're in this area, maybe we can talk a bit about your LNG potential, LNG load profile demand. Would it be fair to say that it's a function of the weather?

A. MR. OSLER: It's a function of the weather meaning is it affected by the weather? Yes. Is that the main thing that's driving it? I don't think so.

Q. Well, let's put it this way. If I have above average water conditions, will I need a lot of LNG?

A. MR. OSLER: If -- water conditions as distinct from whether it's warm or not warm? I wasn't sure which --

Q. My apologies, but let's deal with this in terms of water conditions.

A. MR. OSLER: Okay. Let's talk about water conditions in two contexts. One, variability from year to year; and the other one, variability from different times of the year. In both cases it's very, very important to the requirement. And I'll leave it at that for the moment.

Q. Well, let's take it the next step further because if you have somebody who's cross-examining you when you leave that hanging, well, of course, I'm going to move into that area.

So let's look at it from the concept of water conditions and variability from year to year. If I have above-average water conditions, I will not -- is it fair to say I will not need a lot of LNG?

A. MR. OSLER: It is fair to say that, under the current loads that we're talking about.

A. MR. MORRISON: Depending on weather.

Q. Depending on weather in relation to?

A. MR. MORRISON: Well, it's really, really, really above-average cold for above-average long periods of

time, you might need more LNG.

Q. And that's the concept of degree days. Is that correct?

A. MR. MORRISON: Sure. It's weather and water together.

A. MR. OSLER: But when we looked earlier together the 31 water years, you can see the variability from year to year in the diesel that you could displace by using LNG. And it varies a great deal, particularly -- it varies a great deal no matter what the load is, but from the point of view of an LNG supplier, it has zeros along a number of years at the moment that don't inspire confidence if you're the guy trying to sell it.

Q. That's correct. From an LNG supplier, you could come knocking on the door fairly promptly if you have low water conditions, but then if the water conditions go on a run of above average for three years, they might not see you for three years. Is that correct?

A. MR. OSLER: That's what the information could tell you unless the load gross a bit more. And we're at a very sensitive spot on the load. A little bit of growth would mean we probably need LNG every single year, but it would still vary a great deal between the water condition extremes.

Q. So from a supplier's perspective, you're not what they would call the ideal customer.

A. MR. OSLER: That would probably be a good summary, yes.

Q. And typically when you're not the ideal customer, they will want to see some sort of annual payment so that when you come knocking on the door they will have the ability to serve you. Is that correct?

A. MR. OSLER: If you want a firm supply in a context where they've got lots of other people shopping at their door, the way in which suppliers deal with that is: Give me a firm minimum amount you'll pay, and I'll give you a firm minimum amount I'll supply.

If you have the conditions that exist right now, that's not the top of their mind. And there are various strategies that people can look at to deal with that, including aggregating other loads and all those other things that are talked about.

The other thing that you have to keep in mind is that although the load varies a great deal, we have two engines -- or we have three engines in this project. So we have a maximum amount that we can actually consume at any one time, which limits how much diesel you can displace, but also puts a top on how much LNG you need no matter what the water conditions are. It's around 80 cubic metres a day, round numbers, with two engines.

Q. I'd like to move to another area of cross-examination.

This is in relation to the existing diesel units MD1 and MD2. And before I give you the reference in the information request I'd like you to go to, I'd like to actually check it myself. And I'd like to refer you to YECL-YEC-1-7, and just let me know when you're there.

Is the panel there in terms of the... YECL-YEC-1-7?

A. MR. OSLER: **Yeah.**

Q. So what we have in this is Table 1, operating hours for WD1 and WD2 end of 2013. You see that WD1 has 41,804 hours on it, and WD2 has got 38,202?

A. MR. OSLER: **Yes.**

Q. Now I'd like to refer you to YECL-YEC-1-1, page 3 of 3. Have you got that?

And there's -- it's line 10, (e). It says "Maintenance schedules for Yukon Energy's diesel fleet are as follows..." And at the very bottom of it, it says Mirrlees engines. Are the Mirrlees engines MD1 and MD2 -- WD1 and WD2?

A. MR. OSLER: **Yes.**

Q. And it says minor overhauls at 2, 4, 6, 12,000 hours; major overhauls at 24,000 hours?

A. MR. CAMPBELL: **Correct.**

Q. So if we go back to YECL-YEC-1-7, am I correct in assuming that WD1 and WD2 are not up for a major overhaul

until they get to the 48,000 hour level?
A. MR. CAMPBELL: Well, that would be for the second major overhaul.
Q. Yeah. Second major overhaul.
A. MR. CAMPBELL: Yes.
Q. Okay. And if I flip the page on YECL-YEC-1-7 and I look at Table 2, and it says; operational hours, 2010, 2011, 2012, 2013. So in the last four years, the total number of operating hours for WD1 is 108.3 and WD2 is 77.30. Is that correct?
A. MR. CAMPBELL: Correct.
Q. So they're not used a lot.
A. MR. CAMPBELL: Correct.
Q. How often do you test WD1 and WD2?
A. MR. MORRISON: We test all our engines every month.
Q. Every month. In the period from 2010 to 2013, in terms of the monthly tests, has there ever been a major failure with respect to WD1 or WD2?
A. MR. MORRISON: I can't tell you off the top of my head, Mr. Chairman.
Q. Is that something that you could ask your plant manager?
A. MR. MORRISON: We can do that.
Q. Okay. I'd like to move to another area of cross-examination, and I noticed in your application that

there is nothing about an LNG revaporization costs. Do you know what revaporization of LNG refers to?

A. MR. MORRISON: I'm not sure what you're referring to. Go ahead. Explain it.

Q. I've got LNG in liquid form. I have to get it back to natural gas in short order if I'm going to put it into an engine. So presumably -- and not presumably -- that's a misstatement, it's just straight wrong -- I will need to somehow get my LNG warmed up so that it goes back into a gas.

A. MR. CAMPBELL: Yes.

Q. For the purposes of your LNG engines, how much natural gas is going to be required to do that?

A. MR. CAMPBELL: None.

Q. None. So are you assuming that the heat from the operation of the natural gas engines is going to provide you with the energy that's required to revaporize the LNG?

A. MR. CAMPBELL: That's correct. And in order to start these natural gas engines, there's a small electric heater that will provide enough heat to vaporize enough liquefied natural gas to start the engines up.

Q. So your evidence is, is that using the glycol cooling loop, as I understand it, there will be sufficient heat when the engines, natural gas engines are in operation, to revaporize all the natural gas that's required for those engines so that they can produce electricity.

A. MR. CAMPBELL: I'm not sure you quite got it right. There would be enough heat in the glycol loop to vaporize the LNG when the natural gas engines are not running. When they are running, they will actually be capable of generating more heat than they can generate power. So there is a lot of heat available both for vaporizing and for heating some of the balance of plant activities, yeah.

Q. So there's not going to be any additional use of natural gas other than what's being used in the natural gas engines for the purposes of providing the heat that's required for revaporization.

A. MR. CAMPBELL: Correct.

THE CHAIR: Mr. Austin, I'm just going to mention that it's 4:22, so we'd like to try to get out of here so we can move on to the evening session at 4:30. But I'll leave it in your hands in terms of when you'd like to cut off or how much in terms of the next line of questioning.

MR. AUSTIN: I think it would be convenient to cut off now because I don't want to start an area that extends beyond 4:30, and I've got no control over how long it's going to be --

THE CHAIR: Right.

MR. AUSTIN: -- because I'm not the one that answers the question.

THE CHAIR: Exactly. Okay. So with that,

we'll recess until -- well, we have the community meeting this evening starting at 7:00. So again, you're all welcome to come to that. And then the regular hearing will begin tomorrow at 9 a.m. Thanks very much.

(Proceedings concluded at 4:23 p.m.)

PROCEEDINGS ADJOURNED TO 9:00 A.M. APRIL 1, 2014

Certificate of Transcript

We, the undersigned, hereby certify that the foregoing pages 1 to 192 are a complete and accurate transcript of the proceedings taken down by us in shorthand and transcribed from our shorthand notes to the best of our skill and ability.

Dated at the City of Whitehorse, Yukon Territory, on March 31, 2014.

"A. Jones"

A. Jones, CSR(A)
Official Court Reporter

"D. Gerbrandt"

D. Gerbrandt, CSR(A)
Official Court Reporter

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