IN THE MATTER OF the Public Utilities Act
Revised Statutes of Yukon, 2002, c. 186, as amended

and

General Rate Application for 2008-09 by Yukon Energy Corporation

PROCEEDINGS

May 5, 2009
Held at High Country Inn
Whitehorse, Yukon

Volume 1

TAKEN BEFORE:

Wendy Shanks Chair
Robert Laking Vice-Chair
Jody Woodland Member
Kathleen Avery Member
Richard Hancock Member
APPEARANCES

Wendy Shanks Chair
Robert Laking Vice-Chair
Jody Woodland Member
Kathleen Avery Member
Richard Hancock Member

__________________________________________

Giuseppa Bentivegna, Esq. Board Counsel
Dwayne Ward Board Staff
Bob Clarke Board Staff

Kori St. Jean, CSR(A) Realtime Reporter
Georgina L. Lawrence, CSR(A) Production Reporter
Julie Snijder, CSR(A) Production Reporter

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R. J. Landry, Esq. For Yukon Energy Corporation
L. G. Keough, Esq. For Yukon Electrical Company Limited
T. D. Marriott, Esq. For the City of Whitehorse
M. Buonaguro, Mr. For Utilities Consumers’ Group
J. F. Maissan, P.Eng. For Leading Edge Projects Inc.

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THE CHAIR: Please be seated.

Good morning, and welcome to sunny and warm Whitehorse. And if I said "sunny and warm," make no question, I did say "sunny and warm Whitehorse." One of the few hearings we've had it's been sunny and warm.

I would like to call this hearing to order. Today starts the oral public hearing phase for Yukon Energy Corporation's (YEC's) 2008-2009 Generate Rate Application (GRA).

I would like to first introduce the Board members. To my immediate right is Robert Laking, vice-chair of the Yukon Utilities Board. To my far right is Jody Woodland member. To my immediate left is Kathleen Avery, member of the Yukon Utilities Board, and to my far left is Richard Hancock, member of the Yukon Utilities Board, and I am Wendy Shanks, chair of the Board.

This YEC 2008-2009 Generate Rate Application hearing has been convened as the result of an application received by the Yukon Utilities Board on
October 6, 2008, from the Yukon Energy Corporation (YEC) requesting approval for their 2008-2009 GRA, Generate Rate Application.

For the record, I would like to introduce at this time Board counsel, Giuseppa Bentivegna; Board staff, Dwayne Ward and Bob Clarke. Court reporting is being provided by Independent Reporters, and if any party requires a copy of this transcript for this hearing, they should deal directly with Ms. St. Jean from Independent Reporters.

The Board's executive secretary is Deana Lemke. And if anybody has any questions with respect to process or procedural matters generally, they should speak to Ms. Lemke, and she is at the side of the room.

On April 24th YEC filed an update to its 2008-2009 GRA, where YEC is seeking approval for a revenue requirement of 29,085,000 for 2008 and a revenue requirement of 31,462,000 for 2009. Rather than the 29 -- is this cutting out a little bit? Just let me know when you're done.

Is that working now? Can...
everybody hear? I don't think it is. Is that appropriate?

Other than the 29,217,000 for 2008 and the 31,599,000 for 2009, which were originally set out in the application.

YEC is also requesting approval of rate adjustments by class for all related customers of YEC and YECL and the inclusion of Pelly Crossing in the hydro rate zone schedules and for the removal of Pelly Crossing from the small-diesel rate zone schedules as well.

Further details of the requested rate adjustments are outlined in pages 5 through 7 of the YEC 2008-2009 Generate Rate Application.

In addition, YEC requested interim refundable rates effective November 1st, 2008, and then through correspondence dated October 22nd, 2008, changed the requested date to December 1st, 2008. The Board dealt with this matter through Board Order 2008-16 and 2008-17 respectively.

YEC also requested future draws from the Faro dewatering account to address delays in the final connection timing of the Minto and Pelly Crossing loads to the
Carmacks-Stewart transmission project and secondary sales revenue losses, if any, arising below -- rising due to below-average water flows in any year after 2008.

With respect to this application, a notice was issued with Board Order 2008-15, dated October 30th, 2008. Within Order 2008-15, the Board ordered YEC to public in display ad form a notice of application and prehearing conference no later than November 5th in such appropriate local news publications in YEC service area. YEC was also ordered to make the application and supporting materials available at its office at Number 2 Miles Canyon Road and as well as in its district offices in Mayo, Dawson, and Faro.

By way of a letter dated December 19th, 2008, the Minister of Justice authorized the Board to incur the necessary expenses to hold a hearing as under Section 50 of the Public Utilities Act.

A process schedule for this application was proposed with Board Order 2008-15 and confirmed with Board Order 2009-1. The schedules further revised
with Board Order 2009-3, when YEC requested more time to provide responses to information requests given the large volume of the information requests.

The Board adjusted the process again, through Board Order 2009-4, when YEC was directed to provide better IR responses by April 14th, 2009, and directed to file its 2008 update by April 24th, 2009.

The Board would like to follow the following schedule for this hearing. The Board would like to sit from 9 to 5 p.m. each day, with a 15-minute break occurring at approximately at 10:30, depending where we are at any time in the day, and lunch is planned for approximately 12 to 1:30 each day, with an afternoon break occurring approximately at 3:30 p.m.

If any party has a cellphone, I ask that it be turned off for the proceeding. And to facilitate the marking of exhibits, Ms. Lemke has circulated a list of exhibits to date.

As was determine in the process schedule, simultaneous written argument
is to be received by the Board by May 22nd, 2009, with simultaneous written reply to be received by June the 5th, 2009. Written argument and reply is to follow the outline of the issues list included in Appendix B to Board Order 2009-1.

We would like to commence the hearing by having interested parties register for the record, and the order for parties for cross-examination will be the order of registration. And I would ask the Board counsel, Ms. Bentivegna, to facilitate that process at this time.

MS. BENTIVEGNA: Thank you, Madam Chair.

We will start with the registration of the applicant, Yukon Energy Corporation.

MR. LANDRY: Thank you, Madam Chair.

My name is John Landry. That's L-a-n-d-r-y, for the record, and I represent Yukon Energy.

MS. BENTIVEGNA: Then if we can have Yukon Electrical Company Limited.

MR. KEOUGH: Thank you, Madam Chair.

Good morning.
Loyola Keough for the Yukon Electrical Company Limited.

MS. BENTIVEGNA: City of Whitehorse.

MR. MARRIOTT: Good morning. My name is Marriott, initials T. D. I represent the City of Whitehorse.

MS. BENTIVEGNA: Utilities Consumers' Group.

MR. BUONAGURO: Good morning. My name is Michael Buonaguro. I'm counsel for the Utilities Consumers' Group, and I am here today by myself, thanks.

MS. BENTIVEGNA: Mr. Maissan?

MR. MAISSAN: Good morning. My name is John Maissan, representing myself and my firm, Leading Edge Projects.

MS. BENTIVEGNA: Mr. Percival?

I don't believe he's here.

And is there anyone else who wishes to register at this time?

That appears to be all.
the intervenors -- applicant and intervenors,

Madam Chair.

THE CHAIR: Thank you,

Ms. Bentivegna.

At this time I will turn

the mic over to you, Mr. Landry, for the YEC

opening.

MR. LANDRY: Thank you.

Madam Chair, what I

thought I would do to start with is to

introduce the panel, which is already sitting

at the panel table, and then after that we will

have the panel sworn and we can mark the

opening exhibits.

Madam Chair, the

Yukon Energy will be calling one panel, and

that is the panel that is to your right. And I

will introduce, starting on your far right,

Mr. Morrison, who is the president and CEO of

Yukon Energy Corporation. And to his right is

Cam Osler, who is a principal of InterGroup

Consulting Group [sic] to Yukon Energy.

To Mr. Osler's right is

Mr. Patrick Bowman, who is also a principal

with InterGroup. And to his right is
Mr. Mollard, Ed Mollard, who is the CFO of Yukon Energy Corporation.

And for the record, the CVs of the witnesses are attached as Attachment C1 to Exhibit B-10.

And perhaps, Madam Chair, we could have the witnesses sworn at this time.

ED MOLLARD, duly sworn.

PATRICK BOWMAN, duly sworn.

CAM OSLER, duly sworn.

DAVID MORRISON, duly sworn.

MR. LANDRY: Madam Chair, before we get to the opening statement, I thought it might be helpful for the Board and also to the intervenors if each of the witnesses could, in general, give some ideas to the responsibilities in the preparation of the application and IRs and the updates.

So if I could start with Mr. Morrison and go down the panel from him.

Mr. Morrison?

YEC PANEL EXAMINED IN CHIEF BY MR. LANDRY:

A MR. MORRISON: Madam Chair, I will be dealing with the policy and general operational matters.
MR. OSLER: Madam Chair, I will deal with the matters arising from the resource plan in the other hearings we have had since 2005 and the general history of the corporation and the regulatory regime in Yukon.

MR. BOWMAN: Good morning, Madam Chair. I will be dealing with matters related to the application document itself, the preparation of the document, and how it arises, starting with Yukon Energy's business plan and working through the general regulatory standards that are required.

MR. MOLLARD: Madam Chair, my focus will be on aspects of revenue requirement and certain capital projects, the background and costs associated with those projects.

THE CHAIR: Thank you.

Exhibit Number A-1:
YUB letter to Minister of Justice re YEC GRA, October 17, 2008.

Exhibit Number A-2:
Board Order 2008-15 re YEC proceeding and regulatory schedule, October 30,
Exhibit Number A-3:

Exhibit Number A-4:
Letter from Minister approving YEC GRA, December 19, 2008.

Exhibit Number A-5:
Memo to Parties of Pre-Hearing Conference, January 2, 2008.

Exhibit Number A-6:
Pre-Hearing Conference Agenda, January 7, 2008.

Exhibit Number A-7:
Exhibit Number A-8:
YUB IRs to YEC, January 30, 2009.

Exhibit Number A-9:
YUB memo to all Parties re YEC request for extension to IR Response deadline, February 23, 2009.

Exhibit Number A-10:

Exhibit Number A-11:
YUB memo to all Parties re YEC request for extension to IR Responses deadline, February 24, 2009.

Exhibit Number A-12:

Exhibit Number A-13:
YUB memo to all parties re further information requests, March 25, 2009.
Exhibit Number A-14:
YUB memo to all parties re further information requests, March 27, 2009.

Exhibit Number A-15:
Board Order 2009-4 re further information responses, April 7, 2009.

Exhibit Number B-1:
YEC cover letter to YUB re 2008-09 General Rate Application, dated October 6, 2008.

Exhibit Number B-2:
YEC 2008-09 General Rate Application.

Exhibit Number B-3:
YEC Workshop presentation, January 6, 2009.

Exhibit Number B-4:
Landry e-mail re hearing dates, January 8, 2009.
Exhibit Number B-5:
YEC letter re hearing dates,

Exhibit Number B-6:
YEC letter re Board Order 2009-1 and
Phase II, January 22, 2009.

Exhibit Number B-7:
YEC request for IR Response deadline
extension, February 20, 2009.

Exhibit Number B-8:
YEC reply re request for extension to
file IR Responses, February 24, 2009.

Exhibit Number B-9:
YEC comments on further IR responses,
April 1, 2009.

Exhibit Number B-10:
YEC cover letter re Updates to filing
and IR responses, April 24, 2009.
Exhibit Number B-11:
YEC Complete IR Responses, April 24, 2009.

Exhibit Number C1-1:
Yukon Electrical Company Ltd. request for Intervenor status, December 1, 2008.

Exhibit Number C1-2:
YECL letter re hearing dates, January 9, 2009.

Exhibit Number C1-3:
YECL letter re legal counsel, January 9, 2009.

Exhibit Number C1-4:

Exhibit Number C1-5:
YECL IRs to YEC, January 30, 2009.
Exhibit Number C1-6:
YECL reply re YEC request for extension to file IR Responses, February 24, 2009.

Exhibit Number C1-7:
YECL request for further information from YEC, March 19, 2009.

Exhibit Number C1-8:
YECL comments re further information from YEC, April 6, 2009.

Exhibit Number C2-1:
City of Whitehorse request for Intervenor status, November 25, 2008.

Exhibit Number C2-2:
City of Whitehorse letter re runoff rates and hearing schedule, January 14, 2009.

Exhibit Number C2-3:
City of Whitehorse IRs to YEC, January 30, 2009.
Exhibit Number C2-4:
City of Whitehorse retainer letter,
February 9, 2009.

Exhibit Number C2-5:
City of Whitehorse reply re YEC request for extension to file IR Responses, February 24, 2009.

Exhibit Number C2-6:
City of Whitehorse letter re YECL and UCG request for further information, March 27, 2009.

Exhibit Number C3-1:
Utilities Consumers' Group request for Intervenor status, November 4, 2008.

Exhibit Number C3-2:
Public Interest Advocacy Centre (IPAC) letter re Utilities Consumers' Group retainer letter, December 22, 2008.

Exhibit Number C3-3:
UCG letter re hearing dates,
January 12, 2009.

Exhibit Number C3-4:
UCG letter re YEC correspondence re
Board Order 2009-1, Phase II,

Exhibit Number C3-5:
UCG IRs to YEC, January 28, 2009.

Exhibit Number C3-6:
UCG letter reply re YEC request for
extension to file IR Responses,
February 23, 2009.

Exhibit Number C3-7:
UCG request for further information,
March 24, 2009.

Exhibit Number C3-8:
UCG request for further information
updates, March 24, 2009.

Exhibit Number C4-1:
Maissan (Leading Edge) application for
Intervenor status, October 18, 2008.

Exhibit Number C4-2:

Exhibit Number C4-3:
Leading Edge IRs to YEC, January 27, 2009.

Exhibit Number C4-4:
Leading Edge reply re YEC request for extension to file IR Responses, February 23, 2009.

Exhibit Number C5-1:
Percival request for Intervenor status, December 1, 2008.

Exhibit Number C5-2:
Percival e-mail re representing Hamlet of Mount Lorne, January 8, 2009.

Exhibit Number C5-3:
Percival e-mail re YEC correspondence
re Board Order 2009-1, Phase II,

Exhibit Number C5-4:
Percival IRs to YEC, January 31, 2009.

Exhibit Number C5-5:
Percival reply re YEC request for
extension to file IR Responses,
February 23, 2009.

Exhibit Number C6-1:
Cathers request for Intervenor status,
December 4, 2008.

Exhibit Number C7-1:
Giesbrecht request for Intervenor
status, December 4, 2008.

Exhibit Number D1-1:
Department of EMR request for Observer
status, November 28, 2008.

Exhibit Number D2-1:
Paul Kishchuk (Vector Research)
request for Observer status,
December 5, 2008.

Exhibit Number D3-1:
Carcross/Tagish First Nation request for Observer status, December 5, 2008.

MR. LANDRY: Now, Madam Chair,
yesterday I sent electronically, or we sent electronically, to the Board and to interested parties the opening statement that we indicated we -- or that Yukon Energy would be making today. And so we do have extra copies, if people would like a written copy. So I don't know whether the Board has actual written copies before them.

THE CHAIR: Shall we mark that as an exhibit and then hand it out?

MR. LANDRY: Yes.

THE CHAIR: In that case, we mark B-12.

Exhibit Number B-12:
YEC opening statement.

MR. LANDRY: Does the Board need copies, Madam Chair.

THE CHAIR: We have copies here,
thanks.

Does everybody have

copies now?

MR. LANDRY: So, Madam Chair, I think

we are set to begin, and perhaps I will hand

the mic over to Mr. Morrison, and he can

provide Yukon Energy's opening statement.

THE CHAIR: Please proceed,

Mr. Morrison.

MR. MORRISON: Thank you, Madam Chair.

Madam Chair, members of

the Panel, Yukon Energy is pleased to be here

today in front of Yukon Utilities Board with

our 2008-2009 Generate Rate Application to

reduce rates for most customers throughout the

Yukon. The proposed rate reductions reflect

benefits from timely completion of the

Carmacks-Stewart Stage 1 project, connection of

the Minto mine and Pelly Crossing to the grid

in November 2008 and then added new firm sales

of surplus hydro generation.

In my opening statement

in 2005, I said that Yukon Energy is committed

to work with the Board to find a mechanism to

ensure that in the future, we are before the
Board, on a regular basis, in an open and transparent manner. This is our fourth appearance before the Board in a public hearing since Spring 2005. Yukon's Energy's ability today to propose rate reductions is testimony to the work of many parties since 2005, including the Board's timely hearings held in 2006 and '7 to review Yukon Energy's 20-year resource plan, the power purchase application with Minto Explorations, and the Part 3 energy certificate application for the Carmacks-Stewart project.

Yukon Energy submitted its current application to the YUB on October 6, 2008. It reviews our activities and that of the Board since the last general review of Yukon Energy's revenue requirement by the YUB in 2005. In addition to requesting approval to reduce rates for most retail customers throughout Yukon, Yukon Energy's application requests approval to recover costs to supply customers in 2008 and 2009 and seeks approval of specific additional proposals to best ensure that Yukon Energy can move forward in a manner that meets the needs of Yukon
ratepayers.

I will highlight four of these proposals. First, the proposed capital expenditure levels support enhancement of system capability to displace future diesel generation -- excuse me, to displace future base-load diesel generation requirements and to provide reliable bulk supplies at a time when existing surplus hydro generation created by mine closures is diminishing due to ongoing and projected load growth.

Second, the proposed operating and maintenance expense levels support maintaining and improving the services for customers and the working environment for Yukon Energy employees and provides the appropriate support for meeting governmental regulatory and environmental requirements.

Third, the proposed retail rate reductions focused on first block energy rates ensure that second block or runoff rates do not move further away from efficient price signals and will result in rate reduction benefits being materially enhanced for the majority of retail customers.
Fourth, increasing
residential second block or runoff rates
provides a modest first step that is feasible
today to begin the process of restoring
efficient price signals for residential
electricity sales in Yukon. This approach will
significantly enhance rate reduction benefits
for a vast majority of residential customers
throughout Yukon.

Yukon continues to offer
the lowest electrical rates in Northern Canada.
The 2005 application reviewed Yukon Energy's
success in addressing ongoing cost pressure
since the closure of the Faro mine in 1997 and
1998 and did not seek changes -- any changes to
firm residential or general service rates.

Today -- today's
application deals not only with the 2008 and
2009, it deals with the system enhancements and
efficient price signals needed to sustain
Yukon's advantage in the coming years. Yukon
development is a young company which will play
a significant role in development of the Yukon
in the future.

In addition to the
successful completion of the numerous
regulatory processes undertaken since 2005,
this application is another important step in
allowing Yukon Energy to play that role.

As was the case in 2005,
there is much to be done over the next several
years, and Yukon Energy will be actively
engaged with the Board and key stakeholders to
ensure that we deal with the necessary
regulatory requirements in an open and
transparent and comprehensive way.

Yukon Energy's 2005
application provided the opportunity for the
Board to establish an orderly process to deal
with key regulatory issues facing both
utilities. It deferred any further retail rate
changes until at least 2007, providing for Faro
dewatering account transfers of up to $292,000
in each year only through -- excuse me, through
2007, while at the same time allowing for a
full open-book review of all Yukon Energy
revenue requirement matters.

However, Yukon Energy's
2005 application also highlighted the need in
future to deal with retail rate matters,
including restoring efficient price signals for
second block rates and addressing the Board's
direction relating to rate shift programs to
target 90 to 110 percent revenue-cost ratios
for all retail customer classes. It was noted
that this would require a review of both
utility's costs-revenue requirements and cost
of service.

The Board's direction to
Yukon Energy and YECL in Board Order -- it's
2005-1 in your written document, it may say
"2," but it should be corrected to be 2005-1 --
began that review process and Yukon Energy
welcomed that opportunity.

Future industrial
customer rates and wholesale rate setting,
consistent simple approach to setting return on
equity for both utilities; updated resource
plans, including new capacity planning
criteria; and future capital -- excuse me,
future major capital bulk power supply options.

As reviewed in IR
responses to YUB-YEC-1-36(a), without
Carmacks-Stewart Stage 1, Yukon Energy's retail
rate revenue requirement today would now have
needed a retail rate increase in 2008 of more than $200,000, and in 2009 of 1.238 million, which translates -- would translate into a 3.23 increase if applied across the Board, reflecting ongoing costs since 2005 for items such as fuel, labour, hearings, and ratebase growth.

Between 2005 and 2008 many steps have been taken to move forward in an orderly manner to deal with the priority regulatory issues, including Board review of Yukon Energy's 20-year resource plan in 2006, resulting in the Board's January 2007 report and recommendations to the Yukon government, which included many key recommendations on various matters, including new capacity planning criteria and confirmation that new near-term capacity was required. There were also specific recommendations regarding several near-term major projects which were proposed by Yukon Energy to enhance transmission and generation capacity on the hydro grid. Each of these projects have been undertaken, and the costs of the projects are included in the 2008-2009 GRA.
The first ever regulated project review by the Board in 2007 resulting in a Part 3 report to the Yukon government on Carmacks-Stewart transmission project. Part 3 certificates were issued for the Stage 1, and it is now in service.

Board review of the Minto mine PPA, which resulted in approval of the amended power purchase agreement in Board Order 2007-6. Order in Council 2007-94 address the industrial rate issue, and the Board approved the prescribed rate in Board Order 2008-13.

Order in Counsel 2007-94 mandates that the rate remain in place until the end of 2012. The Minto mine is now connected to the Whitehorse-Aishihik-Faro grid and is being served under Rate Schedule 39.

Board review of YECL's 2008-2009 GRA and Board Order 2009-2 mark resumption of YECL revenue regulation and enhanced ability to address overall retail adjustments, including adjustment of the Rider F to reflect current YECL GRA fuel price forecast rather than 1997 GRA forecast.
Order in Counsel 2008-149 directs that prior to January 1, 2013, retail rate adjustments must apply equally when measured as percentages to all retail customer classes. In short, considerable progress has been achieved since 2005. Several important regulatory matters have been or are now being addressed.

With that backdrop, Yukon Energy today is seeking approval for a rate decrease rather than requiring a rate increase. Successful completion of Stage 1 of the Carmacks-Stewart transmission project, with in-service achieved before the end of November 2008, within budgets as approved by YEC's board, signifies a major achievement for Yukon Energy yielding overall ratepayer net benefit in 2009 alone of more than $2.6 million.

The application before the Board today allows for a full review of a wide range of matters. Many of these have been canvassed extensively during the IR process, and we are here, ready and willing to deal with any further questions the Board and intervenors...
Yukon Energy's current GRA marks the start of a new stage in the early process that began in 2005. This new stage requires participants now to focus on the processing -- sorry, on the pressing need to address new energy based supply issues and to address rate-related regulatory priorities, particularly any change to be achieved before rate directions Order in Council 2007-94 and Order in Council 2008-149 expire.

Existing hydrogeneration surpluses will likely now be largely utilized within the next few years, resulting in the need to develop new renewable supply sources so that high-cost base-load diesel generation and the related greenhouse gas emissions can be minimized on both the Whitehorse-Aishihik-Faro and Mayo-Dawson grids.

This new reality is reflected in Yukon Energy's GRA and ongoing planning, including customer use impacts through reduced secondary sales measures to begin restoring efficient runoff rate signals and updates to wholesale prices.
Planning and feasibility costs directed at renewable resource development projects identified as potential opportunities to displace 50 to 100 gigawatt hours per year of diesel generation that may otherwise be required on the grids in the 2010 to 2015 time period. These forecasts typically remain in work in progress for 2008 and 2009 and, as such, do not affect current GRA amortization ratebase -- excuse me, amortization or ratebase.

Starting in 2007 the Board also highlighted the need for YEC and YECL to prepare a joint cost-of-service study as part of the current GRA process. Yukon Energy's application proposed that this joint YEC-YECL preparation of a cost-of-service study be delayed towards 2012 in order to focus today on other priorities. However, Yukon Energy now understands, through Board Order 2009-1 and subsequent correspondence, that it is the Board's desire that a joint cost-of-service study be now undertaken.

Accordingly, Yukon Energy has proposed to YECL that as soon as possible
following this hearing, the two utilities meet
to discuss and plan the joint YEC-YECL Phase II
application. This will include effective joint
consultations with interested parties on these
matters.

While the joint
cost-of-service study is being prepared, we
have proposed to YECL that rate design issues
and options also be examined. This will
include rate design changes based on current
relevant OIC directives not dependent on
cost-of-service study outcomes, as well as
planning for future rate design issues that
will arise once the OICs expire in 2012.

Finally, in the interest
of controlling future regulatory costs in the
Yukon, we also propose that the utilities
examine potential future options where YEC and
YECL once again can work together, as in the
1996 and 1997 and earlier GRAs, to address
revenue requirement, cost of service, rate
design, and other matters in a single
integrated hearing process.

Today two of the key rate
topics in the application before the Board are
Proposed Rider U, to focus the retail rate reduction on the first block rather than continuing with an across-the-board rate rider that also reduces second block energy rates, and the separate proposed modest increase in the residential second block or runoff rates.

Although we appreciate that the Board has assigned a low ranking to this issue in the hearing, I would like to make a few comments about the timely importance of these proposals to YEC, and then I will turn the remarks over to Mr. Osler for a review of some of the factors affecting the forecasting revenue requirements.

Madam Chair, the Yukon Energy is the main generator and transmitter of electrical energy in the Yukon. We account for over 90 percent of annual Yukon power generation, all of which is on the Whitehorse-Aishihik-Faro and Mayo-Dawson grids.

I have emphasized today that our concern that surplus hydro generation is rapidly diminishing on these grids, and our forecasts anticipate base load diesel generation recurring relatively soon after
2009, unless we can develop adequate new renewable resources on a timely basis.

In light of what we can see on the near-term horizons, and leaving aside OIC rate directions on this matter, as well as history, Yukon Energy has a vital interest in ensuring that retail runoff rates are once again being adjusted upward today to reflect incremental diesel generation costs. Current diesel fuel prices, let alone the prices likely to re-emerge in the coming years are well above the levels assumed in the current base rates set to reflect the 1997 GRA diesel fuel price forecast.

The current lull in oil prices after the roller coaster ride in 2008 provides us all with a window of opportunity to start fixing this serious rate issue. In Yukon Energy's view, we need to seize the opportunity.

In YEC and YECL's 2008-2009 GRAs are providing much higher new fuel prices -- new fuel price forecast than we had for the 1997 GRA. However, unless a different approach is taken to this issue, such
as what is being proposed by YEC in this application, second block runoff rates -- second block runoff rate charges are going in the wrong direction.

Runoff rates today have already gone down due to YEC's interim rate Rider J reduction and the resent change to reset Rider F to zero. Collecting the adjusted fuel price costs through an across-the-board rate rider will not restore runoff rate charges even to where they were in the fall of 2008.

Yukon Energy's rate proposal in the application are designed to prevent further erosion of the runoff rates and to begin the process of moving these rates back up to reflect the incremental costs of diesel generation on the grids. We think that both of these price signals are timely today and are important steps in dealing with the realities that we face.

Madam Chair, with your indulgence, Mr. Osler, I would like to have him finish the presentation.

Thank you.

THE CHAIR: Please proceed,
Mr. Osler.

MR. OSLER: Madam Chair, the application highlights key factors affecting Yukon Energy's forecast revenue requirements in 2008 and 2009. Pursuant to Order in Council 1998-32, Yukon Energy's rates are intended to provide for recovery of all of its costs, including a fair return. YEC's 2005 application requested a reduction in the fair return on equity, the ROE, to 9.05 percent, based on the British Columbia Utilities Commission ROE determination at that time of a fair prospective return on equity for a low-risk utility, with adjustments required for YEC's specific risk and the OIC directions.

The current application retains the same simple approach for the proposed ROE determination and results in a further reduction to 8.64 percent for 2008 and 8.49 percent for 2009.

The application as filed assumes the connection of the Minto mine and Pelly Crossing would occur at October 1, 2008 and that an interim rate reduction would occur at November 1, 2008.
Service to the Minto mine actually formally began November 22nd, 2008.
And to address billing-change issues raised by YECL, Yukon Energy also requested that the interim rate reduction be delayed until December 1, 2008.

Yukon Energy's update to its application, Exhibit B-10, filed on April 24th, 2009, has provided the resulting required adjustments in 2008 for the timing of the Minto mine and Pelly Crossing connections and for the delay of the actual implementation of the interim rider, as well as other adjustments to update the 2009 ROE, to correct certain errors in the original application, to update the Industrial Fixed Rider F, and to update estimated GRA hearing costs with a proposal to amortize in 2010 the added $300,000 of hearing costs estimated.

The updates result in the following, in summary: First, no changes to the 2009 retail nonindustrial rates, as indicated in the original 2008-2009 GRA filing.

Second, finalize the 2008 retail nonindustrial rates, as charged in that
year, and include a revision to the proposed
Faro dewatering account adjustment for 2008 of
228,000 from a proposed credit in the initial
filing to the account of 141,000, filed in the
original GRA, to a proposed withdrawal from the
account of 87,000, as set out in the update.

Yukon Energy's April 24th
update also provides a summary of 2008
preliminary unaudited actual results, with
explanations for major variances for the GRA
forecast. Overall, Yukon Energy's preliminary
actual ROE for 2008 of 7.2 percent highlights
material operating and maintenance cost
increases above GRA forecasts that will result
in actual returns for this year being below the
GRA requested ROE of 8.64 percent.

Oil price forecasts are
an important factor as well in Yukon Energy's
forecast rate revenue requirements, affecting
diesel fuel prices used to forecast diesel
generation costs, furnace oil prices used to
forecast secondary sales revenues, and the
Industrial Fixed Rider F to adjust the Rate
Schedule 39 energy rate from the November 20,
2006, diesel fuel prices, as required.
As everyone knows, oil prices were exceptionally volatile in 2008 and remain uncertain today for any forward-looking forecast.

Each GRA provides the best forecast available at the time of filing, and the Rider F deferral account then protects YEC and YECL from actual diesel fuel and secondary sales price variances from the last approved GRA forecast.

The current Yukon Energy GRA oil price forecast generally reflect the Rider F adjustments by the two utilities (YEC/YECL) as of August 1, 2008. The secondary sales rate in the forecast in the GRA reflects actual rates charged in 2008 and a forecast for 2009 based on the rate for the last quarter in 2008.

The April 24th, 2009, update reduced the Industrial Fixed Rider F to reflect final approvals for YECL fuel prices provided in Board Order 2009-2 for YECL's GRA.

Overall, in Yukon Energy's forecast for 2008 and 2009, diesel generation fuel cost adjustments remain...
far less important than secondary sales revenue adjustments. As a result, reductions to the oil price forecast, as filed, that affect both diesel generation and secondary sales, would increase YEC's retail rate revenue requirement for 2009 and reduce the rate reduction for that year.

And the Board and interested parties can find an example of what I'm talking about in the response to City of Whitehorse YEC-1-16(e), where the more--where the oil prices were taken for early this year, and they showed a reduction in 2009 rate reduction of about $448,000, or about one-quarter--one-third of what we proposed as a reduction.

There are few other key factors that I will highlight affecting 2009 revenue requirements. First, the Mirrlees refurbishment and the purchase of the Minto diesels. In the 2006 resource plan hearing, Yukon Energy faced significant pending winter peak capacity shortfalls on the WAF, Whitehorse-Aishihik-Faro system.

Following the resource
plan hearing, YEC has secured cost-effective options for 25.4 megawatts of Whitehorse-Aishihik-Faro diesel capacity in a staged and flexible manner over the period to 2012. The total cost forecast by 2009 for these -- this capacity is 6.855 million, for 16.4 megawatts of this capacity increase.

Second, a Faro dewatering account regulatory liability. The application does not seek to extend the earlier annual withdrawals that applied in 2005, 2006, and 2007. It requests approval to apply 463,000 of the Faro dewatering account to the reserve for injuries and damages. And based on the April update, also to apply $87,000 to fund the outstanding balance of the 2008 rate revenue requirement. The resulting balance of 641,000 will remain available to address specific contingencies, one of which was noted in the application.

Third, the reserve for future removal and site restoration. In 2005 the Board directed the Yukon Energy cease annual appropriations to this reserve and advised when this amount -- this account
reached $2 million. The account remains today in excess of 5 million, and accordingly no new appropriations to this reserve are requested in this application.

Madam Chair, in closing, in order to assist the Board and all participants, two attachments are provided to this Exhibit B-12 to effectively deal, first of all, materials arising since the workshop in January. The first attachment summarizes the update provided in Exhibit B-10 and the resulting changes to the main application, just for the convenience of parties. And Attachment B summarizes the list of exhibits that sort of flow and where the various matters are, for people's easy convenience.

Thank you.

THE CHAIR: I just want to make sure that -- our copy of B-12 doesn't actually have the attachments. I stand corrected.

Thank you, Mr. Osler.

Mr. Landry, I turn it back to you.

MR. LANDRY: Thank you, Madam Chair.

That is all that we have,
effectively, in direct, so the panel is open
for cross-examination.

THE CHAIR: Thank you.

In that case, Mr. Keough,
are you prepared to proceed with your
cross-examination?

MR. KEOUGH: Thank you, Madam Chair, I
am.

YEC PANEL CROSS-EXAMINED BY MR. KEOUGH:

Q Good morning, gentlemen.

I just wanted to start
off with, I guess, a request for some
clarification as to what YEC is seeking with
respect to what I will call "Phase II issues,"
rate design issues in the context of these
proceedings. To be honest, we are a little
confused, based on the application and then the
Board's ruling, and then of, of course, your
letter that you referred to of May 1, YEC's
letter to Yukon Electrical, and now the opening
statement. So I just want to go through and
make sure that we are all on the same page in
terms of what the company is requesting.

Now, in the cover letter
to your application of October 6, you indicate
that the GRA deals primarily with Phase I revenue requirement matters. And it does say you are not going to address Phase II, cost of service and generate design matters, correct, in the second paragraph?

A MR. OSLER: Yes.

Q And that second paragraph also recognizes that there is a requirement that YEC work jointly with Yukon Electrical on Phase II matters, correct?

A MR. OSLER: You are referring to the October 6 cover letter?

Q Yes. The second paragraph.

A MR. OSLER: Yes. Yes.

Q As I am sure, we are all aware, the two companies have common rate schedules?

A MR. OSLER: Yes.

Q So any changes to the rate schedules would impact Yukon Electrical and its customers, correct?

A MR. OSLER: Any changes to the rate schedules with affect all of the Yukon customers that are affected by the change to the rate schedule.

Q Including those of Yukon Electrical?
A  MR. OSLER:  All the customers: Yukon Electrical, Yukon Energy.

Q  I just wanted to confirm that YEC did not consult with Yukon Electrical with respect to the changes that are proposed in this application.

A  MR. OSLER:  Correct.

Q  Now, I take it, based upon your opening statement, or portions thereof, that YEC does not, at least at this point, consider Order in Council 2008-149, dated October 3, 2008, as precluding the companies from conducting a cost-of-service study and looking at rate redesign?

A  MR. OSLER:  Correct.

Q  Now, if I understand the opening statement, am I correct that, notwithstanding the Board's prior ruling as a result of the prehearing conference, YEC is still proposing the rate redesign issues, that they be addressed in these proceedings as per the original application?

A  MR. OSLER:  Yukon Energy has not amended its application, and it is still proposing the specific rate matters that are in...
its application.

Q And you are aware, I'm sure, that in Board
Order 2009-1, Appendix A, the Board addressed
the issues to be considered in this hearing and
indicated that these rate redesign issues
should be given a lower ranking? You remember
that?

A MR. OSLER: Yes, sir. Mr. Morrison
referred to that in his opening comment and
also referred after that to how the company
views the importance of these matters and why
we would like the Board, Madam Chair, to
consider the company's submission.

Q Is it, in your view, reasonable for parties to
this proceeding to have relied upon the Board's
decision that was previously made when
preparing for this proceeding?

A MR. OSLER: Yes, it would be
reasonable. On the other hand, the matters are
still in the application and, in our view, the
matters are relatively straightforward, and we
hope we can help people understand them and
deal with them in the course of the hearing,
which is one of the purposes of a hearing.

Q Is YEC seeking in some way to change or vary
MR. OSLER: I don't think we have
made any attempts to do that, sir.

Q Now, I wanted to chat with you a little bit
about the proposed change to Rate Schedule 42,
which I gather is still on the table. And I
wanted to chat with you a little bit about the
relative impact that that proposed change would
have on YEC and Yukon Electrical.

And, sir, do you have
available to you a copy of an aid to cross that
we distributed yesterday?

A MR. OSLER: Yes, we do.

MR. KEOUGH: Madam Chair, yesterday we
forwarded to YEC a package containing three
aids to cross, one of them dealing with this
matter. And it's my proposal throughout the
cross to address them. They are not extensive,
and my proposal would be to distribute them,
and if Mr. Landry has any objections to any of
them as I get to them, I am sure I will hear
from them. I know he is a little bit of a
shrinking violet on these things, but I would
propose to distribute them and then have the
Board follow along while I talk to the witnesses about them.

THE CHAIR: Mr. Landry, have you any comments?

MR. LANDRY: I have no difficulty with that, Madam Chair. I am fine to mark the whole package as an exhibit, if that's what my friend would like to do.

THE CHAIR: Mr. Keough, would you like to mark it one exhibit.

MR. KEOUGH: Given that they are physically stapled together, Madam Chair, it probably would make more sense to make it as one exhibit.

THE CHAIR: I reference that as C1-9 somewhere.

Exhibit Number C1-9:

Bundle of aids to cross.

MS. BENTIVEGNA: While that's being done, I was going to ask if Mr. Keough was going to file -- he referred to a letter of May 1st, I believe, from YEC to YECL in the previous questions, and I'm not sure if there was another letter in there as well.

MR. KEOUGH: You are correct. I did
make reference to that letter. I do not have it available for filing. It is a YEC document. If the Board would like to have it, I may consider it more appropriate that YEC file it, because it is their letter.

THE CHAIR: Mr. Keough, was that a letter that's Exhibit B-1?

MR. KEOUGH: No, Madam Chair. This is not a letter -- this is a letter dated May 1, 2009, from YEC to Yukon Electrical that is not, to my knowledge, on the record.

THE CHAIR: Mr. Landry?

MR. LANDRY: If I understand counsel's -- Board counsel's point, I think it was just that there was reference to the letter, and perhaps to have the record straight, put the letter on.

From my perspective, evidence is evidence, so I have no difficulty in if my friend wants to put it in as one of his exhibits or our exhibits. It does not -- it doesn't matter to me.

THE CHAIR: Who wants the exhibit?

MR. LANDRY: I think it was the Board counsel who thought it would be appropriate for
the record, which I appreciate. But, you know, we can mark it as a Yukon Energy exhibit, that's fine. I don't have a copy of it in front of me.

THE CHAIR: You undertake to provide that copy, Mr. Landry?

MR. LANDRY: I will. I'll make sure that we can get copies, and it can be marked as the next exhibit once we have it.

THE CHAIR: Thank you very much.

MR. KEOUGH: Thank you, Madam Chair. I wanted to confirm that the panel had a copy of the aids to cross, or do you need to me --

A MR. OSLER: We have copies, thanks.

MR. LANDRY: Madam Chair, while my friend is distributing that, although it can be marked as an exhibit, I'm not completely sure what the questions are going to be in relation to that, and I obviously reserve my right to deal with the questions as they arise.

THE CHAIR: Okay.

MR. KEOUGH: Thank you, Madam Chair. That's totally fair.

Q MR. KEOUGH: Gentlemen, if you have
the aid to cross in front of you, I'm going to ask you to turn to pages 3 and 4 of that exhibit, which outlines two scenarios with respect to the Wholesale Rate Schedule 42. And I would invite you to take a look at the scenarios, and if you disagree with my characterization at any point, please let me know.

But Scenario 1 is intended to depict the situation when we are dealing with existing rates and where diesel is on the margin, and where Yukon Electrical's actual load or consumption is 10 percent above the forecast.

Now, maybe we can start making sure we have the same terminology in mind. When we talk about diesel being on the margin, what does that mean for YEC?

A MR. OSLER: In simple terms, it means that YEC, let's take the Whitehorse-Aishihik-Faro grid as the focal point, because I think your example is focused on that, if I am not mistaken, Mr. Keough. YEC is faced with generation requirements such that it has to run diesel, not just for a few
moments of peaking but throughout most, if not all, of the year. We call that on the margin for the year base-load diesel generation. The concept of the margin means that it's the last source of generation that the utility is relying upon in order to meet the load requirements.

And in Yukon we either use for generation hydro or wind, or when we can't use that anymore, we rely on diesel, and we say it's "on the margin."

Q Could diesel be on the margin during a month as opposed to a year?
A MR. OSLER: Yes.
Q All right.

Now, in the example that we have provided, Scenario 1 in the aid to cross, do you understand -- it sounds like you have gone through this and found out what we are depicting here; is that right?
A MR. OSLER: We have gone through the example you provided yesterday afternoon --
Q Right.
A MR. OSLER: -- and have, you know, tried to understand the math and the fact that
one page tries to do one thing and one page
does another. I wouldn't say I understand more
than that.

Q Would you be able to agree with me that
Scenario 1 depicts the existing rates, and if
diesel were on the margin and Yukon Electrical
sales or load was above forecast, and with the
assumptions of the split there, that the
revenues to Yukon Electrical from the ERA
charge would be as depicted on the upper
portion of page 1 of 2, where there is the rate
of 10.45 cents per kilowatt hour times the
extra energy, to come up with revenues of
277,949?

A MR. OSLER: Mr. Keough, the first
question you asked, the answer is no. So maybe
we want to go back to the beginning.

Q Are you waiting for me?

And so you didn't agree
with the math?

A MR. OSLER: No. Your first question,
if I recall the series, was, Do I agree that
this reflects existing rates. And my answer is
no.

Q And could you explain why not.
MR. OSLER: Because if we were looking at the revenue situation for Yukon Energy, as it's being depicted here, the cost situation that Yukon Energy would face today is not the same as it was in 1997, and therefore Yukon Energy, when it does have diesel on the margin, is paying the diesel fuel forecasted applied in 2005, not the ones that applied in 2007 -- 1997, sorry, I misspoke. So there is no reflection on this page, that I can find, of that situation. So it does not reflect the existing situation, from Yukon Energy's point of view.

Q So you are suggesting that if diesel were on the margin, the additional expenses to YEC would not be the ERA charge times the subject energy amount?

A MR. OSLER: That is correct. And maybe for the sake of the Board and everybody else, Mr. Keough, we should explain ERA. I leave that to you.

Q Certainly. Go ahead.

A MR. OSLER: The concept of the ERA, energy reconciliation adjustment, is to deal with what happens if there is a change from the
forecast used to set the wholesale rate in a GRA, because the wholesale rate is just an average of all the forecast elements.

The ERA concept arose when diesel was on the margin in the '90s all year round. If Yukon Energy in fact had to increase its generation requirements beyond what had been forecast and had to, say, provide an extra 10 percent, which I think is the basis for this example, of energy to Yukon Electrical, it had to use diesel to run it. You would be paying the cost of the diesel; you wanted to make sure it was getting it back, it wasn't charging YECL only an average lower rate. That is what this is about.

That's why I'm raising the point, Mr. Keough, that this example doesn't seem to reflect the existing situation as approved in the 2005 revenue requirement application received for the cost of diesel.

Q So you are saying that in fact -- sorry, you are saying in fact the YEC would charge Yukon Electrical a different rate. What would that rate be and according to what rate
schedule?

A MR. OSLER: Let me, if I could, pass the numbers over to Mr. Bowman, because he's been going at the numbers more than I have. I'll stick to the high level. But when we get to the numbers, he can do it.

Q Certainly.

And, Mr. Bowman, maybe you can identify the ERA charge and the schedule that authorizes that charge for me, please.

A MR. BOWMAN: Yes, thank you. The sheet that I'm looking at, just to -- so we're clear about the number side, is the one that shows ERA charge at 10.45 cents on energy volume, leading to a revenue to YEC of 277,949 and it has a sub 1 beside that.

Q Correct.

A MR. BOWMAN: And then the second component of that is matched to the YEC additional fuel expense of 277,949, which has a sub 2 beside that.

The matter that Mr. Osler has been referring to are in this portion of
the table. They don't relate to where the
sub 1 is. As the situation presently exists,
where diesel is on the margin and
Yukon Electrical's load up, the line that says
ERA charge at 10.45 is the rate that would be
applied today. That is pursuant to Rate
Schedule 42, and I can take us there if you
want, the detail. But that is the number that
would be charged related to the ERA.

And it effectively simply
gives a stepped rate or second block rate on
the wholesale component of the bill, and it's
been there for some time.

The energy volumes are,
as you put them, so the revenue would be as you
put it here.

The thing that we are
noting as our concern with portraying this
existing is where you see the sub 2. That
situation on sub 2, meaning the matching of the
revenue with the cost, is the way that the ERA
charge was developed in 1997, and it reflects
YEC's fuel prices from 1997 and the rate that
existed in 1997.

The portion Mr. Osler was
referring to was that no longer exists, because in 2005, YEC rebased its fuel prices. That earlier number was based about 30 cents a litre, and in 2005 they were up to approximately 56 cents a litre.

So if you were actually portraying the existing situation, as you say, assuming that nothing in GRA is approved, sub 1 would remain 277,949. Sub 2 would be 536,698, and that's because of the higher price of fuel that -- that would exist that YEC would be required to book, based on its 2005 approval. So that was the value that we were commenting on, it was the sub 2.

Q Okay. And just for clarification, are you suggesting that Yukon Electrical would have to pay YEC for the additional power -- additional energy? Would they have to pay the 277 or the 536?

A MR. BOWMAN: As the rate presently exists coming out of 2005, where no change is made to the wholesale rate schedule, Yukon Electrical today would be required to pay 277,949, while YEC would incur costs of 536,698.
Q Okay, and that's fine.

Now, if I go to the lower portion of this schedule, you will see depicted there the Yukon Electrical residential revenues. And if you sum the two that Yukon Electrical would get from both the residential and general service, then what we have done is do a net so that, effectively, the manner in which the rate schedule existing rates would operate is that there's a degree of neutrality where Yukon Electrical, what it is required to pay, is relatively close to what it is entitled to collect?

A MR. OSLER: Well, I'm not sure there is a question yet, sorry.

Q Would you agree with that? Have you followed the math that far?

A MR. OSLER: Let's go in steps, baby steps.

I would agree that the math is the math. We have no problem with the calculations.

The actual math on the page is what it is. Whether it reflects all the riders and everything else is not something
we are terribly worried about.

Secondly, the bottom of
the page shows the net effect on
Yukon Electrical, and I think the math is -- if
you accept all the assumptions, the math is
fine. I would comment that for those of us who
are involved in the history of this, I don't
think that Richard Stout from ATCO or myself
looked at it as incremental would necessarily
be distributed the way you have assumed.

I think the basic ERA
approach assumed that, generally speaking, the
incremental volumes would tend to be on the
second block, in which case the math would
change. You would be closer to the 10.45 cent
revenue to capture, rather than the lower
number.

I just put that on the
record from the point of view of how people
talked about it back in the '90s from both
companies.

Finally, the net impact
on YEC, as Mr. Bowman's gone through, is not
correctly reflected on the bottom of the page.
Yukon Energy would end up with around $259,000
hit net, given the fuel approved costs from
2005 that we put -- have to put on our books
and the rate we would be entitled to recover
from Yukon Electrical, given the current rate
schedule.

Q So in 2005 in YEC's application, it didn't seek
a change to the ERA charge amount of
10.45 cents?

A MR. OSLER: We didn't try and change
any rates other than secondary sales rates.
And even in this application, the part at Tab 4
that discusses this says we're trying to look
forward to the future when diesel might once
again be on the margin, in the sense that the
ERA contemplates, and prepare for it. We are
not forecasting this to be the case for the
test years. So we are not expecting this to
happen, just to be a possibility that it would
emerge in the test years, but we wanted to get
the rate schedule starting to move and reflect
it so everybody got the right signal, including
YECL.

Q And speaking of that, could we just flip the
page now to page 2 of 2, Scenario Number 2,
which depicts what we understand would occur if
your proposal or your proposed change to
Rate Schedule 42 was accepted. And have you
gone through the math here and determined that
the math is correct, or is -- do you have
issues with the math on this page?

A MR. OSLER: Well, on checking the
math, I'll let Mr. Bowman comment.

Generally speaking, the
big changes on this page, for the sake of those
who haven't been studying it, is to reflect the
fuel price that is in the current GRA from
Yukon Energy, correct? I mean, that's the
assumptions you have put in here. And the ERA
as amended by Yukon Energy in its application,
342, to reflect that fuel price, the
37.37 cents per kilowatt hour, implication of
the fuel prices that are in this application
for the Whitehorse-Aishihik-Faro system plus
line losses plus an allowance for O&M
operating.

Q So --

A MR. OSLER: So, essentially, the
element says, if the Board approves that
forecast and approves Rate 42 as proposed, if
Yukon Energy had to run diesel in the margin,
its cost would be recovered from YECL as per
the original intent of the ERA. That's what it
shows.

Because the runout rate
that Yukon Electrical can recover from its
customers has not moved materially,
Yukon Electrical would be picking up 705,000,
$706,000. From Yukon Energy's point of view,
the math is correct, and the outcome is the way
it's described.

Just Mr. Bowman has
reminded me of -- the basic point is that is
the cost that is incurred to supply that extra
load, if you accept the assumptions. Whether
the extra load occurred in Watson Lake or
occurred in the WAF system, 10 percent more
load would incur the costs the company has for
fuel costs plus O&M. If the runout rates are
not appropriate, the company will get a hit
like this.

The ERA just simply
transfers where the hit is. It transfers it
from Yukon Energy to Yukon Electrical, who is
responsible for the retail customers.

Q And I guess --
A MR. OSLER: And reflects the order of
council direction that, generally speaking, the
wholesale rates are supposed to keep
Yukon Energy whole.

Q And I guess my question to you is, Wouldn't it
be more orderly, to use a word that's common
throughout the opening statement and parts of
your application, to look at the whole
situation at the one time so that you can take
into account the impacts on both companies and
as opposed to adopting what I will call a
"piecemeal approach" to rate design that has
these type of consequences? Wouldn't that be
more sensible, as opposed to doing it --
looking at one component and not being able to
factor in what would happen as a consequence of
changing one component of rate design? Why
wouldn't it be sensible to wait and do it all
together, as apparently you are now prepared to
do?

A MR. OSLER: We're dealing with
Yukon Energy's revenue requirement, and the
matter of the wholesale rate is fundamental to
Yukon Energy's ability to recover its costs.

The matter of incremental
rates is fundamental to the ability of each utility to try and match costs to serving load for incremental changes beyond its forecasts. These are fundamental revenue requirement matters, quite separate from a lot of other matters that we would discuss, Madam Chair, when dealing with a whole plethora of rate matters.

So, generally speaking, I would say it's best to deal with the matters that fundamentally affect revenue requirement when dealing with revenue requirements and the ability of keeping each company whole at that time, and dealing with all sorts of other issues, if you must, later.

Q So YEC would consider it to be more orderly and efficient to adopt an approach that would not involve both utilities, would not involve consultation, would not involve consideration of customers, but rather would just isolate one component of the rate design and change it in isolation. That would be your view of an orderly process; is that right?

A MR. OSLER: Madam Chair, Yukon Energy has put together an application in the
circumstances to try to deal with issues as it
best it can in an orderly manner. Dealing with
these matters, we hope that we can see
improvements to the way of dealing with them in
the future, and we will be dealing with
consultation on the other matters Mr. Morrison
referred to with YECL and with other customers
in the manner Mr. Morrison described. So the
application is there.

Q All right.

Now, am I correct that
currently the runout rate for both general
service and residential rate classes is the
same?

A MR. OSLER: It is, to the best of my
recollection, in the Whitehorse-Aishihik-Faro
system and the hydro and the large diesels. I
don't recall off the top of my head whether it
is in all of the other rates zones.

Q That's fine. That's the one I was talking
about. YEC is proposing to change the runout
rate for only one of the classes, the
residential class, but not for the general
service class; have I got that right?

A MR. OSLER: That is correct.
Q And is that because of your concern with the impact that a change would have on the general service rate class at this point in time?

A MR. OSLER: It's fundamentally because in order to implement changes at this time, for any rate class, we have to make sure that we comply with Order in Council 2009-149, I believe the number is, that we can't rebalance revenues between classes.

This is not an unusual situation. We have had the same situation in the early '90s for all of our rate cases that the two companies dealt with the Utility Board on, and we certainly adjusted runout rates at that time.

But in this particular situation, given the gap between where the rates are today and where they would need to be to reflect the forecasts in this application, we were concerned that trying to deal in this application with the general service class was simply too complicated, and so we had to have a discussion with YECL and a broader discussion in order to deal with it.

And the fundamental
problem, Madam Chair, is that the big
difference between the two rate classes,
residential and general service, is where the
bulk of the energy sales are in the two rate
class -- in the two rate blocks. In
residential most of the sales, as well as most
of the customers, are in the first rate block.
In the general service
class, although most of the customers consume
only in the first rate block, most of the sales
are in the second rate block. So if we were to
start increasing the runout rate in the second
rate block, we're affecting a very large volume
in the rate class of the sales, and we think,
as we did discuss we -- a long time ago, ten
years or so ago, maybe the time has come to
talk about breaking -- getting a few more rate
blocks for the general service class.
That is not something
that Yukon Energy would ever try and do on its
own. It would like to do it in conjunction
with and cooperation of YECL.

Q Well, I suppose it is nice to hear that you
think you should consult with YECL on some
things, but apparently not all. And I'm
struggling again with this orderly approach here versus a piecemeal approach, because it seems to me that you currently have the same runout rate for both the general service and residential rate classes. You want to change one without any input or consultation. You don't want to change the other because it's more complicated and you think you need consultation.

Again, isn't this reflective of a piecemeal approach, and isn't it better to do it all together when the impacts of the rate changes on both companies can be considered? Why isn't that the appropriate way to go here? I am still struggling with that, Mr. Osler.

A MR. OSLER: Madam Chair, the application has been before all parties since October 6. It had been Yukon Energy's interest to see this matter that I just discussed dealt with, but it hasn't seemed to be possible to date, because of the desire to delay everything to another hearing.

I repeat what I said earlier. The application has attempted to deal
as best it can, from Yukon Energy's point of view, with the priority issues and the realities as Yukon Energy sees them. It's in the Board's hands as to how we all deal with it, but Yukon Energy's put forth the best proposals it can put forth in the circumstances, and it is very concerned about these matters, given what Mr. Morrison discussed.

Q All right. Thank you. I think we can leave it to argument.

I would like to also just talk to you a little bit about another matter that's mentioned in your application, at page 2 of the application, and specifically I'm talking about where you're dealing with matters that have been -- this is the overview, I suppose. Just confirming it is the actual -- I think I am in the actual application.

And you talk about the other proceedings that have taken place in the last several years, and you mention the 20-year resource plan in that proceeding. And I just wanted to make sure again that we are on the same wavelength here with regard to what that
20-year resource plan did or didn't do, because it's referred to subsequently quite a bit.

Can we agree that the purpose of the resource plan review was to examine YEC's capacity planning criteria and the planning process as well as the criteria for longer-term development opportunities, and there is also some four near-term projects discussed?

A MR. OSLER: Generally, Madam Chair, I think that Mr. Keough's gone through the topics that were in the application in the resource plan. The focus was essentially on generation and transmission planning in Yukon over the next 20 year, 2006 to 2025. And it focused on capacity planning criteria, as noted as a topic, and the implications of that for near term and longer term. And it focused on approaches to deal with the near-term to 2012, and for the four or five key projects listed there as major projects, which Yukon Energy wanted the Board to have the opportunity to review, and in Mr. Morrison's earlier commitment to bring before the Board projects costing $3 million or more, if possible, and
also tried to deal with ways to approach
longer-term planning beyond 2012, in light of
all the various particular industrial scenarios
that might emerge in load scenarios.

And it all responded to
an order setting the hearing in the Minister's
letter that, I think succinctly said, asked the
Board to review it from the point of view of
the near term, as we have just discussed it,
and the longer term, as we have just discussed
it.

Q And I did crib it from the actual
recommendations themselves, so I didn't go out
on a limb there.

Can we agree that YEC
committed, and I think you just mentioned this,
to seek Board approval prior to construction of
any new capital projects costing $3 million?

A MR. OSLER: No. I can't agree to
exact wording, Mr. Keough. I can agree that
Yukon Energy committed, in the resource plan,
to try to bring before the Board, for its
review and recommendations, project costing --
capital projects costing $3 million or more.

The problem in Yukon is
there is no statutory provision for the Board to approve capital projects of utilities. But in the past, we have found ways to deal with that, and the resource plan was a good example in terms of the ministerial direction and the resource plan document, the Board giving recommendation. And we thought that that process had honoured Yukon Energy's commitment that Mr. Morrison had made in 2005 for the four or five key projects that were listed in the resource plan for the near term.

Q Well, I don't want to quibble, but I did once again read or take this note from page 1 of 55 of the Board's recommendations, and I didn't think I was mischaracterizing it when I was asking if YEC had committed to bring before the Board new or revised -- what it says here, and maybe I will just read it, third paragraph it says (quoted):

"Within the Plan, YEC 'committed to seek YUB review, prior to construction, of any new capital projects costing $3 million or more.'"

Is that an accurate depiction of the commitment YEC made?
A Mr. OSLER: Yes. And you have -- quoting the Board, you have used the word "review" rather than "approval." That's the only point I was making. And I'm looking at Figure 1.1 from the resource plan, and, you know (quoted as read):

"YEC will seek YUB review for projects over $3 million."

So that's the only point. It's a review, not an approval, because there is no statutory basis for the Board to approval a capital project.

Q Unless it's been designated?

A Mr. OSLER: Unless it's been designated.

Q Can you --

A Mr. OSLER: Sorry, excuse me. If it has been designated, the Board still is only giving a recommendation to the Minister, under the statute.

Q Fair enough.

Can we also agree that the plan did not seek, and the Board certainly did not give, specific approval to any capital projects during -- as part of its
recommendations?

A MR. OSLER: Mr. Keough, Yukon Energy did not seek the Board's approval and it did not get the Board's approval. The Board does not have the basis for giving same.

Q I think we are on the same page.

A MR. OSLER: The Board did recommend various projects, and Yukon Energy has been moving forward with those recommendations.

Q Would you agree that the whole process was to develop a report that was submitted to the Commissioner and executive council, as was requested by the Minister of Justice at the time?

A MR. OSLER: Yes. The process involved a submission of a report to the Minister of Justice, I believe it is.

Q Did the government ever act on any of the recommendations and provide a response to either the Board or YEC with respect to those recommendations?

A MR. MORRISON: Madam Chair, I haven't seen a formal reply from government on that matter. In terms of response, I would take it that the -- dealing with the energy certificate
on Carmacks-Stewart would be, you know, a response in that manner. But there's no formal written response that I'm aware of.

Q And can we agree that 20-year resource plan proceeding was not a proceeding regarding the granting of an energy project certificate or an energy operation certificate under Part 3 of the *Public Utilities Act*?

A MR. OSLER: Certainly can agree to that. It wasn't anything like that.

Q Now, if I could get you to just look at page --

MR. KEOUGH: Madam Chair, I am just wondering what time you are taking a break this morning.

THE CHAIR: We had indicated approximately about 10:30, but if you want to finish up your section or the line of questioning in that area, or is this an appropriate time for you?

MR. KEOUGH: This would be a good time. I'm moving to page 1-6, so it's probably good now.

THE CHAIR: In that case, we will take a 15-minute break at this time.

(BRIEF ADJOURNMENT)
THE CHAIR: Please be seated.

Mr. Keough, you are prepared to proceed with your cross-examination?

MR. KEOUGH: I am. Thank you, Madam Chair.

Q MR. KEOUGH: Gentlemen, I just wanted to take you to page 1-6 of the application, just as a point of reference, where you discuss the matter of the bulk power system resource planning and development challenges that you found with regard to the filing. And I note that YEC says that this has been a key focus for it in recent years, and I just wanted to try to understand YEC's long-term plan, if I can call it that, and your strategy for meeting what you see as the power supply needs in Yukon.

Now, while I'll get into some specific projects later on, I just wanted to see if we could agree that before moving forward with any of these projects, YEC should have to demonstrate that there is a real need for the project.

A MR. OSLER: We are talking about the
projects that were in the resource plan, and
the point -- one of the points of the resource
plan was to demonstrate that there was a need
and what it was and how this project was the
optimum way to approach meeting that need.

So in terms of near-term
projects in the resource plan, yes, one of the
objectives was to demonstrate need and also to
demonstrate that a range of options were
considered to meet the need and that the
project being proposed was the most appropriate
project to meet that need.

Q And are you saying that all of those points
have been satisfied via the resource plan, so
that there is no need for -- no need -- no need
for the Board to consider need with respect to
capital projects that YEC is bringing forward?

A MR. OSLER: What -- we have to be, of
course, specific as to which projects we're
talking about.

The -- Madam Chair, the
resource plan itself divided near term and
longer term. So in doing Mr. Keough's
question, I will talk about the near term,
Chapter 4 of the resource plan. The idea of
the resource plan with regard to Chapter 4 was to do what Mr. Keough had suggested, to find a vehicle that Yukon Energy could come before the Board and have those projects dealt with with regard to need and justification and have recommendations flowing on those matters for those specific projects, because we have no other mechanism to do that before we have actually incurred the costs and come to you for approval to have them put in rates. So that was the idea when we first put together that resource plan with respect to those specific projects in what was Chapter 4.

Those projects, Mr. Keough, were the Carmacks-Stewart transmission line, Aishihik turbine, the Mirrlees, and at one point we also had in Marsh Lake.

Q I guess on a more general basis, when YEC brings forward a proposed project, should it have to demonstrate that there is a real need as opposed to what I will call potential "speculative need" for the project?

A MR. OSLER: It has to be a real requirement or need that has been met, not just
a speculative need. But in some circumstances, the planning activities, in order to be able to meet a potential future need, have to take place long in advance. And you can't just wait until everything is crystal clear, so it depends what stage of the project we are talking about.

But the near-term project concept was to focus on things that were needed near enough in the time horizon that the exercise would be worthwhile. We would be dealing with real needs, real projects, and not too much speculation.

Q Does YEC consider that it should be required to demonstrate that the proposal it's bringing forward is the most optimal way to meet the identified need?

A MR. OSLER: Yes, Mr. Keough and Madam Chair. That was one of the ideas of the resource plan was to demonstrate not just need but that options have been considered, that the projects being proposed in the near term, to use Mr. Keough's phrase, were optimal, were the best ones that were available.

Q And if the need is purportedly some future
growth in demand, is there an obligation on YEC to demonstrate that that future growth and demand will occur?

A MR. OSLER: If the need is dealing with a future requirement, in order to explain the need, you have to explain or justify or support what that requirement is, that load, and under what conditions you think it would emerge and why you were focusing on trying to be ready for it. All loads have some degree of risk and uncertainty to do with them. Some of the bigger ones have a lot more risk, and we dealt with that through the purchase power application, through the Carmacks-Stewart application, all of which flowed from the resource plan.

We were dealing with material risk of a load and our ability to serve it on a timely basis.

Q So you are agreeing with me that you -- if the driver is forecast future growth, then YEC should provide evidence to the Board that demonstrates that that future growth will take place?

A MR. OSLER: I think the answer I gave
is it will demonstrate what the need is what
knowledge it has about it and why it thinks
that that need is serious enough and likely
enough that Yukon Energy is paying attention to
it. Whether it will for sure take place is
always a matter of discussion, and there will
always be some risk, probably, that the load
has got some risk factors and those should be
discussed when dealing with the issue of need.

Q Should there be a high level of confidence that
the load will develop? Or can you move forward
in the face of considerable uncertainties?

A MR. OSLER: I'm not comfortable
trying to give an absolute answer, Mr. Keough.
I think what the resource plan is showing is
that if you do not want to be stuck with
meeting major new needs by just running some
more diesel, we are going to have to grapple
with the planning problem of what do we do when
and how do we protect ourselves against going
too far before we have some more knowledge or
certainty, but also if we don't do enough in
the planning at various stages, we won't have
any opportunity. We can know for certain to
have a project in place when it is needed to
displace diesel.

So the resource plan, Mr. Keough and Madam Chair, is dealing with that problem. And it is for Yukon and the size of this system and the challenges of major new industrial loads, Chapter 5 was trying to deal with the balancing of the uncertainties about these major new load and the problems of trying to find the right match of new supply options.

And Yukon has some very specific challenges in that regard, we thought, over the next 20 years.

Q Well, would YEC's pursuit of numerous major generating projects, either hydro or diesel, lead it to be a little more optimistic or maybe even aggressive in terms of its growth forecasts?

A MR. OSLER: That sounds like a speculative question to me, but it does not lead YEC in practice, Madam Chair, to be more optimistic about its growth forecast. It just means that if YEC is trying to do innovative things and taking the risks for it, it wants to know it's got the best forecast available, thank you very much, as well as the best
everything else it can available if it's going
to put its neck out and try to make things
happen.

Q We could agree that if you adopted a
conservative approach, then the future
potential demand may not be there, and hence
the need for the project may not be there.
That follows, doesn't it?

A MR. OSLER: Mr. Keough, there is
nothing in it for YEC to make a forecast that
would drive it to be promoting projects that
then fail. So if anything, the more risk you
are going to take to try and develop things to
keep us off diesel, the more you really want to
know that your forecasts are realistic.

The safest thing to do,
looking at history, is just to not do what YEC
is trying to do, just let the growth happen
with diesel and let the customers pay the
charges through the Rider F and everything
else.

But what YEC was
concerned about is the implication of taking
that strategy and trying to understand what
different has to be done to avoid that type of
outcome.

But when it starts to try to plan for renewable resource development, it is vitally interested in having the most realistic forecasts available to it.

I would just say the resource plan, though, started off with a section that said the forecast for the next 15 of the 20 years is a surplus on both grids, and that is the best that we knew at that moment in time. But it was risky. It might change, and we needed to face -- manage those risks.

Q Now, when YEC is considering the construction of new large transmission or generation projects, does it consider a four- to six-year time horizon to be a short-term one, medium-term one, or a long-term one?

A MR. OSLER: Mr. Keough, could you help me in terms of what context you are asking that question? In terms of when the project might start, or in terms of some other factor?

Q I guess in terms of the life of the project.

A MR. OSLER: I think we would -- Yukon Energy would look at a four- to six-year
project life as relatively short.

I'm still puzzled with --

I'm not sure why you'd want to know what we
think of the life of the project, because the
projects we are doing are long-term projects
that last 40, 50 years, so I have a suspicion
we are not communicating. I didn't understand
the question, I guess is what I'm concerned
about.

Q That's fine. We'll get back into it a little
bit later, don't worry.

Now, when you are
developing the long-term plan here, is YEC's
vision to develop hydro or renewable projects
so that you can decrease dependence on diesel?

Is that one of the main drivers?

A MR. OSLER: Yes. And in the resource
plan, Yukon Energy was looking at opportunities
to displace diesel if diesel became required as
base -- base-load generation, meaning
generation required throughout most of the
year, not just for a brief period during the
peak periods of winter. And it was looking to
hydro or renewable resources as are they
viable, what are they, could they displace
diesel, yes.

Q  But your -- I don't want to say your, YEC is concurrently pursuing a number of diesel projects as well, correct?

A  MR. OSLER: Very correct. And, Madam Chair, and the resource plan, the reason for that was because of the capacity versus the energy issues. And we discussed that in the resource plan.

The capacity issues were the issues requiring capability to meet your peak winter peak, your winter peak and have backup in the event of certain contingencies. One of the best examples being the blackout that occurred in January a few years ago when there was a failure of the Aishihik connection during the middle of winter. It occurred during a peak period of the seasons, it occurred in the middle of winter, and it cut the system out of its ability to meet loads for a period of hours or days.

So we went through the capacity-planning process, we got agreement on the basics of a capacity-planning approach, and we said we're short capacity to meet those peak
needs or those emergency needs, and then we
focused on diesel as the cheapest way to meet
that shortfall.

And then energy, which
was the Chapter 5 discussion, much more than
Chapter 4 in the resource plan, is when we have
diesel actually being required, not just for
those peaks, not just for those emergencies,
but for sustained operation of the system, as
it was when the Faro mine was operating, then
we are talking about energy requirements, not
capacity requirements, and we have to look for
something a lot cheaper than diesel, if it's
available. That's the big distinction.

Q Right. And then I guess where I was going is
if you have addressed the capacity issues, and
I thought that was what you were calling
Stage 1 of your orderly development; now you
are on to Stage 2. If you have addressed your
capacity issues and are looking forward what
projects you are going to do, do you take into
account in doing what I'll call an overall type
of cost-benefit analysis the pursuit of
additional diesel projects that will ultimately
be, I guess, displaced by hydro so that the
diesel projects will be backup, I guess, in nature? Is that factored into the overall thinking of the company?

A MR. OSLER: Yes, in the broadest sense of the word the company is aware of its capacity and the different types of generators it has, diesel and hydro or wind.

But in general in the Yukon and on the, say, Whitehorse-Aishihik-Faro system, we have a lot of capability to produce diesel energy. So we're not usually planning to build a diesel plant in order to run it for a while as a diesel operation and then have it displaced by hydro. We don't have a big issue there because there is a lot of diesel capacity in order to meet the capacity requirements.

There is a lot of diesels on the system that could be run if they needed to be run, you want to pay the bill, to meet energy needs. It is a bit different in some other systems, like the one I have in Manitoba where we have 90 percent of our generation coming from hydro. And trying to meet energy requirements can become a shortage issue, and you sometimes have to worry about building your gas plant or something
else.

Q So you are telling us that given the current capacity situation, when you are looking at additional diesel projects, you want to be very careful that they're not going to just be of a short-term nature and displaced by, if the plan is developed according to Hoyle, as they say, you would displace those and have new hydro, or you are cognizant of that, is what you are telling us?

A MR. OSLER: The company is generally cognizant of the issue, yes, that I think you are raising about making sure we don't have diesel as being redundant. But the diesels are being renovated or refurbished or acquired in order to meet the capacity issue I was talking about, and anything the company's looked at in terms of forecasting and options, the diesels are required to meet that requirement. They're not -- they're not redundant.

Q Now, some of the projects we'll get into in more detail later carry a fairly large dollar ticket item with them, correct, with some of the hydro and transmission projects?

A MR. OSLER: Yes.
Q Are we on the same page that those projects would not be economic without a significant contribution from the government primarily?

A MR. OSLER: I think in order to deal with that type of question, Mr. Keough, I would prefer you to ask it on a project-specific basis so I don't misinform.

Q Okay. We'll get into that later, then. Now, the reason I asked in a general basis is because what I did want to ask you is, When the company is looking at the source of funds for this project, is there a distinction drawn between whether the funds come from the ratepayer or the taxpayer?

A MR. OSLER: There is a distinction made between whether the funds have to be put into ratebase and recovered through rates or can come from some other source that would not seek recovery of the cost through rates.

Q So if the costs aren't going to be bourne by the ratepayer, then they're not factored into your utility picture, correct?

A MR. OSLER: If there's a project that costs $30 million and, you know, 15 million of it is coming from customers or other sources
that don't have to be recovered through rates, we treat it as a contribution. It reduces the ratebase, and only the net that's left, the 15 million, in my example, is in ratebase and has to be recovered through rates on a rate-of-return basis.

So we treat any source of funds that allow us to reduce ratebase in that manner the same way, whether they come from customers or they come from government or they come from the shareholder as a contribution. They get treated as contributions that reduce the overall cost of the project. It still means the company has to manage, plan, and develop a project for its actual total cost. It doesn't ignore it just because it's got some contributions.

Q Right. But in terms of portraying what I'll call the benefits over the project, what the company would do is they would show, for example, the revenues that will be derived from construction of the project as the benefits, but on the cost side, the costs will be bourne by someone other than the company/ratepayer, correct?
MR. OSLER: I think correct. When we're dealing with the Utility Board and we are dealing with the issue of regulated activities, we try and discuss it from the point of view of the rates and the ratepayers.

Q Right. So when you are talking about the benefits of the project to the Board here or to your ratepayers, you are able to quantify or identify the additional revenues from a project as being benefits, but you can put aside a significant portion of the total cost because those are covered by a contribution from, for example, the government?

A MR. OSLER: Generally speaking, we'd be looking at comparison of alternatives, so we would be saying, if we didn't do this project and we had to run diesel, what would the ratepayers have to pay, because there would be no contributions from anybody.

If we do get a chance to do this capital-intensive project, what will it cost in total, how much can we get in contributions from various parties, and what's the net cost to the ratepayers, and are the ratepayers better off than if we'd had to run
the diesel? That essentially the framework for the analysis.

In order to get the contributions, you have to demonstrate to the other parties that there's benefits in it for them, whether it's government or customer or whomever. And sometimes a lot of discussion in that area may come down to greenhouse gas benefits or development benefits or infrastructure benefits, whatever it -- whatever the government or the customer sees as benefits that would justify giving us the contribution we are relying on.

A lot of other things get considered under the word "benefit," but I am trying to be helpful from the point of view of, I think your question was focused on this utility board and rates.

Q Right. And I'm just trying to make sure we are on the same wavelength with regard to your use of the term "benefits" to this Board and to your ratepayers.

And so the scenario would be that the benefits would be the additional revenues. But you don't have to take into
account the full costs of the project because you are only recognizing the component of any of the cost that the ratepayer would have to pay?

A MR. OSLER: Why I said earlier I want to deal with the question of specific projects and specific questions and not too generally, because the answers will vary quite materially depending on what project we are talking about. But I will stick with what I said before, Mr. Keough, that the benefit is the cost that we save the ratepayers from not having to run diesel. The revenues that we're going to get one way or the other as a regulated utility in meeting the loads that we're required to meet and using the rates the Board has approved, the issue is, can we keep the costs down; can we do something better than diesel? That's the benefit of the type of projects that you and I are talking about at the moment.

Q Right. But when you are talking about keeping the costs down, is a major component of keeping the costs down that the overall costs of the project aren't borne by the utility and its
ratepayers; a significant component is bourne by contribution from the government?

A MR. OSLER: Again, Mr. Keough, we would have to deal with specific projects for me to help you on that particular question.

Q Okay. And we will. And that's fine.

Now, in bringing forward capital projects, does YEC take into account the relatively short-term life of some of the mining projects that appear to be the drivers for the project?

A MR. OSLER: Yes.

Q And how is that done when you look at the long-term life of the assets that are being built? How is that short term factored into the equation?

A MR. OSLER: In the context of a project such as Carmacks-Stewart Stage 1, to take a specific example, Madam Chairman, it is taken into account by the overall strategy to keep the costs that would be in ratebase very low, such that ratepayers would have reaped such enormous benefits during the period of the mine's life, if it indeed ends up being short, because miners are always optimistic that it
will be longer, that the ratepayers really have no cause for concern at all about the net residual, it would still be in ratebase, when and if the mine stopped operating.

And, secondly, we look at load growth of the rest of the system to understand the extent to which load growth is happening independent of that particular mine.

As I said earlier, the opening pages of the resource plan said that within 15 of the 20 years, the surplus would be gone. Bringing on Minto or bringing on other mines simply stops the surplus sooner, but it only stopped it for a few years, or five years or six years, whatever we were forecasting at that time, and then there was going to be a bit more surplus for a few more years.

We looked at those things, Madam Chair, as you know, from the hearings, and came to the conclusion, and recommended to the Board, and the Board recommended to the government, that all of these things be considered that the costs and the benefits were such that these were good projects to recommend for development, taking
all of these things into account.

Mr. Bowman has something he would like to add.

A MR. BOWMAN: Let me just add that the matter you raise about the life of a project was absolutely central to the discussion in Chapter 5 of the resource plan, where it was noting that in terms of deciding on your resource options, the life in many ways is more important than the size.

Mr. Osler made the comment about ongoing growth of domestic loads. It is important to emphasize there is a big difference between the type of mining loads people are talking about these days, Minto at 30 gigawatt hours or Western Copper at 40 or 50 gigawatt hours, in relation to the fact that the ongoing system is going at 5 to 8 to 10 gigawatt hours a year on its own.

If the mine was there for even a relatively brief period of five, six, seven, eight years, by the time the mine closes, the rest of the system has grown to the extent that the resource you put in place to help meet the mine's load is now needed for the...
domestic load. That's vastly different than the situation in the past where you have the Faro mine running at 180 gigawatt hours a year. In the 1992 reserve plan, this matter was reviewed. A whole lot of resource options were looked at to try to get Yukon off diesel and put in place resources that would help meet that load. And the conclusion was, don't do anything. The mine is too big and too uncertain, and if it closed, you would be stuck with a resource that wouldn't be needed to meet domestic load. That's very different than what we are talking about today. We are not dealing with that situation. The life is absolutely taken into account in relation to the size of the system and its needs.

Q And your response there, does it have an assumption that the load growth absent the mine will continue at the rate you identified over that six- or seven-year period?

A MR. OSLER: The resource plan had an assumption of a long-term average growth rate, and it had sensitivities around it that were examined so that you weren't putting all your
eggs in one particular growth number, yes.

Q  Now, speaking of the mines and the load at the mines, could I get you to take a look at your response to UCG-YEC-1-21 REVISED. And it is actually attached to Exhibit B-10, the April 24, 2009, update, about two-thirds of the way through, once you get through the update material, as I see it. That's the most recent version that I have.

A  MR. OSLER: Mr. Keough, which number again, please?

Q  UCG-YEC-1-21 REVISED.

A  MR. OSLER: Thank you.

Q  And I am looking at page 2 of 2, and I just want to see if I understand correctly what this response to B --

THE COURT: Mr. Keough, just a minute. We have a few people who need to get the . . .

MR. KEOUGH: Certainly.

THE CHAIR: Is everybody okay? Does anybody still not have it in front of them?

Please proceed. Thank you.
MR. KEOUGH: Thank you, Madam Chair.

Q MR. KEOUGH: I am looking at the table, and I am just trying to confirm that I am understanding it correctly.

If you look at the description in the left-hand side, the third one down says "Industrial." And if I go across, it says "Forecast 2008," "6845," "Actual 2008," "3,200," and the "Variance," "-53.24%." Do you see those numbers?

A MR. OSLER: Yes.

Q Is that telling me that the actual consumption at the Minto mine in 2008 was 53 percent less than you forecast?

A MR. OSLER: I think so. I mean, essentially, Mr. Keough, and Madam Chair, the update is saying that the mine was forecast, or assumed, if you want to use that word, to be connected October 1 in the GRA, as filed, and it didn't connect until November 22nd. So it's a little bit more than half the time period that it was assumed to be connected it wasn't, for the purposes of 2008.

And we went through in the update all the implications of that
pursuant to the application in terms of how it
affected 2008.

Q Am I correct in my understanding that for 2009,
you are forecasting the Minto load to be
slightly above the minimum take-or-pay level in
the contract?

A MR. OSLER: Yes.

Q And am I also correct that you are not
forecasting that any sales will occur under
Rate Schedule 45 below a grade or a rate
schedule for 2009?

A MR. OSLER: Yes, sir.

Q I am going to get you to flip back to page 2-6
of the application. And there is a discussion
at the -- I guess the lower portion of the
page, last paragraph, about the Carmacks Copper
Mine, and it's not expected to be operational
in the test years; is that correct?

A MR. OSLER: Yes, that's correct.

Q When is YEC expecting it to be operational?

A MR. OSLER: The forecasts have
been -- haven't changed from the time of filing
on that particular mine, and the earliest that
it could be connected is fall of 2011. And
that would assume that they made relevant commitments the fall of this year.

Q And so there is still some uncertainty with respect to whether or not this load is actually going to develop, right? There is still a number of outstanding uncertainties that have to be resolved before you would consider it a firm project?

A MR. OSLER: Very definitely. It's been going through its regulatory processes and coming out the other side now. Just got its quartz mining licence as well as its YESAB review behind it. It has to deal with the water board issue still, and it has to make its financial commitments to proceed to develop the mill and to complete arrangements with Yukon Energy for the supply of electricity.

The way in which we have been monitoring it has been what time period would they have to make those commitments in order for there to be a power requirement by the fall of 2011. The best advice we have is 24 months in advance.

So our efforts are focused on we have got a 24-month window, and
somebody has to sit down and finalize
arrangements with Yukon Energy, and then we
have 24 months. And it's up to the customer in
this instance to let us know when they're ready
to finalize those arrangements and do it in a
timely manner, because they do know that
24 months is needed, so that Yukon Energy has
the potential capability to meet their needs.

Q And they haven't given you those green lights
yet?

A MR. OSLER: They haven't made those
commitments yet, or we'd be talking about a
purchase power agreement. But they have
certainly met with Yukon Energy recently and
said they are still talking seriously about
this schedule. They have not backed off the
schedule, despite the market conditions. And
copper prices have gone back to a certain level
that gives some -- at least interest in keeping
the timing they were talking about.

So they haven't backed
off their timing. They wanted to make that
point clear to us, and they've asked us to take
seriously in dealing with them; you know, take
the project seriously. Don't look at the
newspapers. Take the project seriously, and the market conditions, and keep it as a potential project for the time schedule we are talking about.

But that's a conversation. Actual investment dollars depend on agreements and commitments.

A MR. MORRISON: Which have not occurred.
A MR. OSLER: Which have not occurred.

Q There is reference to a new spur line to serve this project. Is a contribution required, either by the government or by the company, in order to make the spur line economic?

A MR. MORRISON: Madam Chair, the spur line is a -- the mine requires a spur line to connect it to the grid. The discussions that we've had previously with them, it's very clear to -- from our perspective, and it's very clear to them, that the cost of that spur line would be 100 percent covered by the mine itself.

Q And there you are telling us that is the basis upon which YEC would proceed to build a spur line?

A MR. MORRISON: That's correct.
A MR. OSLER: The basis upon which they
would proceed would include that as one key element. There are other elements that would be required to be consistent with the Minto purchase power agreement and the commitment that was made in that agreement and approved by the Board to seek contribution towards the main Carmacks-Stewart line as well from a customer who connections to it, such as Carmacks Copper. So there would be a requirement to cover the cost of the spur line, as was the case with Minto, and a requirement to make a contribution to the main Carmacks-Stewart project cost.

Q Now, still on page 2-7, about halfway down, there is a discussion of the Alexco Resources Corp. project. And again that one is not proposed for the test years?

A MR. OSLER: That project is not expected as an industrial customer to be connected during the test years, but it is a customer of the company as a general service customer, as discussed. And the timing for that project, though, is connection as an industrial customer at some point during 2010. And that is considered as-- in contrast to the
mine we were just talking about, is considered as very likely, and it's much easier for them to connect because they are in the middle of an area where there has been lots of service in the past.

Q Would we be able to agree that that project, though, is likewise subject to considerable uncertainties, still?

A MR. OSLER: I think I would like to describe it the way I just did, that it's a totally different type of risk profile than the Carmacks Copper one. It is in an area where they have developed infrastructure. They can -- subject to getting transformers and things, which take time to deliver, they can connect relatively easily, and they are going -- there is no big spur requirement. There is just transformers and connections to a mill that they have to develop.

They need to start construction this summer, Mr. Keough, in order for them to meet the time period we're on, and they're getting all the signs that they are going to be doing that, subject to getting their final approvals through the YESAB.
So, yes, it's not something that Yukon Energy is relying upon to happen. But it is taking it very seriously that this project is very likely to start connecting into the system in 2010.

Q And in YEC's response to YECL-YEC-1-7, there is a discussion of the Alexco project and reference is made to a commitment that they would make to YEC? Have they made that commitment?

A MR. OSLER: The discussions, Mr. Morrison might want to deal with, in terms of discussions going on with Alexco, there have been no final commitments made, but there are very active discussions.

A MR. MORRISON: Madam Chair, just to maybe help out a little bit on this, Mr. Osler is trying to explain that we characterize different -- these customers -- potential customers we are talking about are in different stages of the development. We characterize how we would deal with them a little bit differently.

Alexco and Yukon Energy
are in the process of discussing a power purchase agreement. That's a step that we have been in for the last couple of months. We haven't finished it, but it does demonstrate, from our perspective, a very different project level than where we are at with Western Copper.

When you get to the point where a company is actually talking about the power purchase agreement and whether or not they want to connect to the grid, we are at a different stage. They are a very different mine than the Western Copper mine. They are going through some regulatory processes. They have some permits to do work. They have a business plan or a mining plan that, you know, they keep us posted on. Just a very different situation, from our perspective.

But the power purchase agreement is the definitive document, from our perspective, in terms of hooking up a new customer.

Q I want to move on to talk about a couple of other area, and we will deal with some specific projects later on when we get to section -- or Chapter 5 of the application. But could I get
you to take a look at page 3-12, 3-13. There is an issue there dealing with the reserve for injuries and damages.

A MR. OSLER: Yes, Mr. Keough, we are there.

Q And I see you have paper copies of this. It may be easier than those who have electronic copies. But I wanted to also take a look at -- or have open your response to YECL-YEC-1-29 [sic] that's dealt with this matter.

First off, I will start with a general question. Does YEC have established criteria that are applied with respect to the charging of items to the reserve for injuries and damages?

A MR. MOLLARD: Yes, we do.

Q Welcome to the fray. And could you identify what those are for me.

A MR. MOLLARD: It's essentially a term from our property insurance policy. The sudden and accidental loss of use of an object, which is defined in the policy as one of our assets.

Q That's it?

A MR. MOLLARD: That is it.
Q I didn't want to cut off the list of criteria prematurely.
A MR. MOLLARD: No.

Q Can items be charged to the reserve if they are not material?
A MR. MOLLARD: We use a limit of $1,000 as anything below that is considered immaterial and is charged to maintenance.

Q Can items be charged to the reserve even if there is not a low probability of them occurring?
A MR. MOLLARD: I'm not sure I understand the question.

Q I am just trying to think of the scenario where if something is regularly occurring, then you could forecast it as part of your O&M, for example, and distinguish it from something that might be of a low probability and, therefore, would not have been forecast, could not have been forecast?
A MR. MOLLARD: We generally don't consider the probability of the event occurring/recurring in the evaluation of whether it qualifies for charging to the reserve.
Q If you have regularly occurring events, would that be something that the company would normally then start to include in its O&M forecast, if you have regular failures of something of a specific nature, would that be -- not be forecastable?

A MR. MOLLARD: It's very difficult to say without having a specific example. And sudden and accidental events are, by their nature, not lending themselves to be forecastable, so it would be very hard to say that I could, yes, forecast without a specific example.

Q And we'll probably get into that later on. Can items be charged to the reserve even if the cause of the incident is normal wear and tear?

A MR. MOLLARD: No.

Q Is that because in order to qualify the event it has to be an insurable incident or an insurable event?

A MR. MOLLARD: Yes.

Q And who makes the call as to whether it is an insurable event? Is it the CFO, or is it some independent insurance adjuster?
A Mr. Mollard: I would make the ultimate call, although I do take the advice of -- we employ a professional insurance broker who, for larger incidents, I will consult him on whether it's an insured loss before I will make that call on whether it should be charged to the reserve.

Q Do you get any signoff or documentation from this insurance expert that it is an insurable event?

A Mr. Mollard: Not generally, no.

Q And you are the ultimate arbitrator here? There is no verification or check as to whether or not the event qualifies or not, just as --

A Mr. Mollard: If it's a material item, I will discuss it both with my insurance broker and with the CEO, if there's a -- you know, an item of several hundred thousand dollars at stake.

Q Now, your -- you said earlier, and I think this is covered in response to the IR I referred you to, YECL-29. Your materiality threshold is a thousand dollars. Is that an appropriate threshold of materiality, given your O&M budget is 12 or $13 million?
A MR. MOLLARD: It's the limit we established. We didn't really set it in connection with the O&M. It wasn't tied to the O&M budgets at all.

Q But you consider a thousand to be material?
A MR. MOLLARD: Yes.

Q Now, one of the aids to cross that I distributed earlier was an extract from a decision of the Alberta Utilities -- what is now the Alberta Utilities Commission, then EUB, and it's a couple of pages from Decision 2003-056. Did you have a chance to peruse that?
A MR. MOLLARD: I did read it, yes.

Q And if you look at the extract on page 10, Section 4.2, you will see the views of the Board and the criteria that are established there.

I take it from our earlier discussion, you would only have -- I suppose you would say that you have the first and second criteria that you apply? Or would it just be the first one?
A MR. MOLLARD: Yes, we definitely do consider the first two, the -- yes, the first
Q And, again, the second one would be in the connection of your thousand dollar limit?

A MR. MOLLARD: The second one is more in connection with the functionality of the unit, if the damage was to the extent that the unit was not functional, that would be the significance criteria for us.

Q Right. Could we take a look at the response you have given in Part B of your YECL-29. And I see things like third party vehicle damage. Would you think that's an unusual event, or is it a fairly common event?

A MR. MOLLARD: In our operation, that's fairly unusual.

Q And what about something like the streetlight being struck by a vehicle?

A MR. MOLLARD: Again, in that case that was pretty unusual.

Q And a broken pole, that would be unusual?

A MR. MOLLARD: In that context with that much damage, yes.

Q So you are telling us that those items would not have been normally forecast as part of your O&M budget?
A MR. MOLLARD: In the circumstances, that's correct.

Q I would like to move on now to talk for a moment about the Faro dewatering account, and it's page 3-14, it's mentioned there.

Now, as I understand it, in the context of the current proceeding, YEC is proposing to use monies in that account for at least two purposes here, well, one being to deal with the delay in the connection of Pelly Crossing, and -- just trying to find my note -- you also want to make use of that account with respect to your deferred study costs? The second one is the reserve -- yeah, reserves for damages, sorry.

A MR. OSLER: Go ahead.

A MR. BOWMAN: On the second one, use of the dewatering funds in respect of the reserve for injuries and damages, yes. In respect of the timing for the connection of the Carmacks-Stewart, in effect, yes, although the dewatering account is effectively used as a regulatory balancing account, if you'd like. It provides an opportunity to offer more stable rates than would otherwise be achieved and to
deal with small balancing entries through the account, rather than having to continually adjust rate riders or the level of rates. So in that regard the dewatering account was always proposed, regardless of the data connection, to be the way in which one balances the '08 revenue requirement compared to the revenues received.

What we didn't want to do was to have to put in place a rider or a rate change at November 1 related to '08 for two months and then have a change at January 1 to become the 2009 level. Rates were designed so that there was a 2009 level determined. And that same rate was then carried back into 2008, so we didn't have a second rate change to deal with.

And the small balance, which was under the order of 100,000, would be taken through the dewatering account as a balancing.

Q So I'm just trying to understand how YEC views this dewatering account because, it seems to me you are using it for a variety of items in lieu of having to seek rate increases.
MR. BOWMAN: Well, not quite, but let me go through it a bit for the benefit of the people in the room.

The funds that we're talking about, we call it a dewatering account, but it's somewhat removed from that nowadays. This is an amount arising going all the way back to about -- going back to 1998, when the Faro mine closed. At that time there was a quick expedited process to deal with the impacts of the Faro mine closing and setting the level of rider needed to deal with the Faro mine close.

There was a whole number of limited scope changes that went through the revenue requirement in order to help keep the rider down, but one thing that was completely uncertain at that time is how much power the mine site would continue to buy once it was in receivership in order to dewater the pits.

That's where the name comes from. In order to treat the water out of the pits at the Faro mine.

So out of that hearing, YEC was ordered to not include in its revenues
but to set aside any amounts related to selling power to the Faro mine site for the dewatering purposes net of any costs that arose. And that order stayed in place all the way through 2004. And 2005 we got those revenues included into normal rates.

So no further amounts were going into this account. It's sort of a residual amount of money that's put aside for the benefit of ratepayers, only to be used pursuant to an order of this Board.

That account was quite large. At one point it was over $2 million that was set aside. In the last rate hearing, rather than implement changes to rates, the Board ordered an annual withdrawal from that accounting in order to balance Yukon Energy's revenue requirement for three years, '05, '06, and '07, and those withdrawals occurred, which brought it down to the level we are dealing with today.

It also provides the opportunity to deal with one-time items, given its one-time money. There is no more money going into the dewatering account. So in order
to help do other actions to the benefit of ratepayers, like deal with a deficit in the reserve for injuries and damages, or deal with balancing the 2008 rates, these funds provide that opportunity to the benefit of ratepayers.

Q Right. I understand that, but what I'm trying to get on the same wavelength with you is that by making use of this account, you are diminishing the benefits that are otherwise available to ratepayers. You are reducing those benefits, the magnitude of those future benefits that's being held there, and you are doing it in lieu of a rate increase.

A MR. BOWMAN: Well, the money that's there, given nothing else is going into it, is available to be used to the benefit of ratepayers, and all of it can only be used once. No more money's going in.

If it weren't used to benefit ratepayers by helping deal with the reserve for injuries and damages balance, rather than having to seek higher rates to deal with the balance, it would be available for something else to the benefit of ratepayers.

But the net effect is the
same. It's a benefit to the ratepayers because it's being used to offset costs that ratepayers would be otherwise be responsible for.

Q But when YEC says, We are here seeking a rate reduction for 2008, part of the reason why you can say that is because you are using the dewatering account balance to offset some costs, right?

A MR. BOWMAN: I'm told you mentioned the rate reduction with respect to '08. I'm assuming it's equally applicable for '08 and '09, although '08 is when we would -- where the application records the offset.

Assuming those amounts would have flown through rates in one year in '08, that's true. More likely when you have a deficit in a reserve account like this, one would determine a way to set a new reserve appropriation that would true it up over time.

So rather than the $100,000 appropriation into the reserve, but for these monies, we might be here saying it's 150,000, in which case the rate reduction would be slightly smaller than what is being proposed today.
Q I would like to get you to turn to page 3-15 of the application, and I just want to talk for a little while about the deferral studies and the other costs and reserves that you have included in this discussion. I just want to get a better idea of what YEC's position is on these items.

Now, if I skip -- I think it's actually page 3-17 that you get into the meat of it. And there we're talking about planning and study costs. As I understand what YEC is doing, is the company is putting the money associated with the various numerated items into a study cost category. And then do you earn AFUDC with respect to the balance in that account?

A MR. BOWMAN: Mr. Keough, I might just make a brief comment about my previous response. I believe I misstated a number. I said that the reserve for injuries and damages appropriation, were applied for, was 100, and would otherwise be 150. Actually, the correct number for 2009 is, it's applying for 150; it would otherwise be 200, as an example. So I just wanted to make sure that was correct for
the record.

In respect of the question you just asked, studies in progress, similar to capital work in progress, YEC has been recording AFUDC on those amounts and records AFUDC amounts in progress exactly analogous to capital. The only exception if you were to go to the Chapter 5 tables on all the different costs is rate case amounts. YEC has not been charging AFUDC on past hearings that are effectively not yet being amortized. They are being carried until the next year rate pursuant to ruling of this Board. It has not been adding AFUDC. They are effectively carried at no cost.

Q Other than rate case reserve, the rest of them are attracting AFUDC?
A MR. BOWMAN: Any studies in progress attract AFUDC.

Q Now, you were careful to day "studies in progress." If a study has been completed, am I correct that you -- again, I am using the royal you -- that YEC would write those study costs off over five years?
A MR. BOWMAN: Any study that is
completed, the same as a capital project, the
costs at that time are crystallized, it is put
into ratebase, and in that case they are
depreciated over five years. And that is also
in the Tables 5.3 to 5.7.

I apologize, Mr. Osler has corrected me on one point. If the studies
were in regards to a potential new capital project, so if you are doing feasibility
studies on a new generation or if it's studies to investigate a problem, that ultimately leads
to a capital project. They are then removed from the studies account and put into the
capital account and added to the overall capital costs of the project and depreciated
over the life of the project. So some studies go that route as well.

Q If the project -- no project materializes, the study costs are written off over five years?
A MR. BOWMAN: Correct.

Q So ratepayers would pick up those costs over that five-year period?
A MR. BOWMAN: It becomes part of the ratebase and part of the revenue requirement for the next time rates are set, yes.
Q Right. And you would also include your AFUDC costs in your overall costs when the rates are set?

A MR. BOWMAN: AFUDC costs charged to the project, while it was in progress, are part of the overall costs of the project, become part of the balance that you'd see in the schedules at the back of Chapter 5 and are amortized over five years, exactly the same as they would be if it was a capital project.

Q And I think it probably would be helpful to actually go to Tab Number 5, because I do want to look at some of these more specifically. And I was looking at the Tables 5-6. I think it's at page 5-31 that I wanted to go to first.

And if you have that handy, I am looking at about four-fifths of the way down the page. I'm not sure how to better describe that.

There is a line called "Total Deferred Study Costs" and "Forecast 2008" is just over 16 million. Do you see that? 16.025 million?

A MR. BOWMAN: Yes, that's it. That's a
gross amount, but yes, that's what it is, the
total deferred study cost comprising
relicencing or licencing activities for the
YEC's facilities as well as feasibility
studies.

Q Right. And if you go back up to the breakdown,
that's got some 6.8 to 6.9 feasibility amounts
and another 8.9 in relicencing.

A MR. BOWMAN: Yeah, those are the gross
amounts that it shows, including both in
service and work in progress, correct.

Q Right.

Now, if I flip over to
Schedule 5.7, on the next page, and I do a --
that's page 5-32, I do a comparison, I see the
total has gone up to 30.8 million, located in
the same relative position as we were
discussing before.

A MR. BOWMAN: Yes.

Q And now we have over 21 million in feasibility
and about 9 million in relicencing.

A MR. BOWMAN: Correct. And of the
21 million in feasibility, approximately
17 million is a work in progress, and
4.4 million is in service or in ratebase at
Q So we are seeing a huge increase in these study costs from 8 to 9, right?

A MR. BOWMAN: Yes.

Q And maybe you could help us out as to what is the main driver of that significant increase, drivers.

A MR. BOWMAN: I can, and it's all included on this table. But I will make a few extra comments as you say to help.

The gross number that we're dealing with, the 30.8 arises primarily as a result of having approximately 15 million in forecast spending on deferred costs in 2009. Of that amount, far and away the largest amount is studies on new generation. If you look further up the page, the GRA is based on forecast cost spending on Mayo B in 2009 of $6.5 million, all of which remained in WIP at the end of 2009 or studies in progress. So it's not in ratebase.

It doesn't affect rates, but there's 6.5 million forecast spending on Mayo B. And the other largest category is other generation feasibility work, which in the
GRA document for 2009 is at $6.8 million.
Again, that amount at the end of 2009 is a work in progress and doesn't affect rates in the rest of the application, and it reflects spending expected to occur at the time the GRA was prepared. Current plans are somewhat lower than that, but nonetheless that's what's leading to your largest portion of the increase. That's about 13 million of the change, which is almost all of it.

Q Right. And so just so we understand, if these projects do not proceed, then this 13 million in '09 and plus the '08 amounts will have attracted AFUDC and will be written off over 5 years and charged to ratepayers?

A MR. OSLER: Just if I could, Mr. Keough and Madam Chair, I think the application makes it clear that all of these costs are subject of ongoing regular review of the type I described earlier in terms of risk management. So the company would hope that if the projects don't proceed it isn't spending the monies you are talking about here. It would only spend up to a certain point, and you'd have to go through each project to know
what point they are at today versus tomorrow.
I will take Mayo B as a classic example. Mayo
B is assuming that people are going ahead on
the schedule of trying to get this project in
service by the fall of 2011 and that in order
to do that they are securing funds as required
and doing all the things that are necessary to
make a decision to keep moving on this project
at the level that this assumes, which includes
aggressive -- doing field work this year and
drilling and also doing all the engineering in
order to be able to start construction next
spring.

Unless things keep
happening that would give the company
confidence that it's prudent to spend those
monies, those monies -- that $6 and a half
million will not be anywhere close to spending
the numbers you're looking at here. And the
same arguments would apply to the other
projects.

If in fact the projects
still keep looking viable and these types of
monies are spent and the project for some
reason didn't go ahead, yes, that answer is
they were going to five-year amortization of costs and if they are on the company's books and they haven't been offset by any contributions from parties.

Q Well, you know, Mr. Osler, with all respect, I mean it is YEC's forecast. I am assuming it is the best forecast you have, and I am just operating on the information that it is there. So is it your best forecast that you are going to spend this $13, $14 million in 2009, and if the projects don't proceed the ratepayers are stuck with the costs?

A MR. OSLER: Madam Chair, I have answered the best I can on that question. The company wants to make it very clear what I just said, that these monies are put into the application but they are -- it's been stated over and over again in the application and IRs they are subject to ongoing review, and they will not be spent if the circumstances arise that the project looks like it's not going to move forward. In order to spend this type of money on these projects, they would have to and keep going through a lot of tests, the board of directors and the management of the company
that would give them confidence to believe these projects are going to happen and that they are -- you know, these monies are prudently and wisely spent.

They do not affect the revenue requirements or the rates proposed in this application, the point that's also been made. So we have simply reflected at the time it was filed the planning provisions as they then were, and they have been updated I think in answers to questions like 38B, you know, reduce some of these numbers. But they are 2 and a half million I am told.

But these we are dealing with stuff that is the essence of the risk management I was talking about earlier, and it has no effect on the revenue requirements before the Board for the two test years or the rates being applied for.

Q We will chat about that in a second. But if I look at the 2008 numbers in this column again on Table 5-7 for those two projects, there is two and a half million together. Was the two and a half million spent in '08 or what was the 2008 number, actual number?
MR. BOWMAN: The -- I would make two or three comments in relation to that. One is it's reported as two rows, but in fact the other generation feasibility is tracking a series of projects. It's not one project. So that's one thing that is probably worth noting.

In terms of what was actually spent, the overall spending to the end of 2008, December 31st, '08, was very close to these amounts. It was slightly above on the Mayo B and slightly below on the generation feasibility, and the total of the two is about 2.4 million so approximately 180,000 above on Mayo B and approximately 260,000 below on the other generation feasibility. But in essence with respect to the type of planning work that goes into developing these numbers is very close to on budget.

Q Is there any benefit to customers being derived from these studies if the projects do not proceed?

A MR. BOWMAN: Well, I think the answer is yes, there are benefits to customers in the event these projects don't proceed. One needs to sort of work through thinking about the
thing Mr. Osler noted about at one point one
would say it's not proceeding, close the
project, and put it over to studies and
amortize over five years. But there's
absolutely no doubt, for example, that part of
the reason we can proceed on some of these
projects today is because in the past people
have done feasibility work in respect of these
sites and in respect of these projects. Even
at the time we filed the 2005 resource plan we
had quite a list of assets in the colloquial
sense from the work that people have done in
past studies on sites. So the studies don't go
away in terms of their value. That would be
one point.

The second one is that
there are products coming out of this that
related to studying these that also have other
uses. And I make some comment in the
interrogatories about things like developing an
overall system generation planning model that's
being used for a number of purposes. So those
type of things have benefits, and a fair bit of
the activities that are going on also relate to
working on something like a Mayo B with the
community. And there's always benefits to
being able to engage with the local community
and work with them through the issues related
to the future with respect to plans.

Now, those are not things
that someone puts into the categories as why
you spend this money. It's not a cost benefit
of those things against the money spent. The
monies are being spent because people want to
get on and do the project because it makes
sense given the loads that are expected to
arise. These are just sort of ancillary items
that suggest that the monies spent don't go to
waste.

A  MR. OSLER:    I'd, Mr. Keough, like to
just add one thing, and in particular monies we
are talking about here that were spent in 2008.
A lot of those monies were spent to make a
filing for the Mayo B project with the
regulators in Yukon.

It was always understood
that that filing was a goal by itself that the
board of directors had approved and that the
benefit of that would be we get the project
regulated and get it approved so that next time
in the worst case you have the environmental
approvals in place rather than having to start
at Square 1, because timing is everything. So
in that specific case, there was a very
specific product, milestone that's there.

Q  Is YEC taking the position that all of the
projects listed in these tables have resulted
in projects that benefited customers?

A  MR. BOWMAN: All of -- I think the
reason you'd see them in ratebase is that all
of the projects listed in these tables are
necessary activities for a utility at a
generation transmission level to undertake in
order to manage and plan for its system. That
would be the basic premise to why the studies
were done, why they were approved by YEC and
undertaken internally and why they were
included in ratebase.

MR. KEOUGH: Now, I will just close
off, Madam Chair. I know we are going over a
bit here, but I just have a question or two if
I might get your indulgence on that.

Q  MR. KEOUGH: Now, Mr. Bowman, you have
mentioned some what I will call ancillary
benefits that might arise to some of these
studies, and you said they wouldn't appear in a
cost benefit analysis. Is there a cost benefit
analysis that demonstrates that all of these
studies are appropriately undertaken and have
some benefits at the end? For example the ones
we have talked about the Mayo B, the 8.1
million and the other generation feasibility of
7.6 million, about $60 million there. Is there
a cost benefit analysis that is done by the
company to show that it's a good idea to do
these studies and spend this money?

A  MR. OSLER: Madam Chair, there were
certainly assessments done before the company
authorizes anybody to be spending money on what
we're looking at here. The assessments depend
on the stage of the project. In the case of
what we described in the application and then
answers to questions, there was an -- at the
time of the resource plan just after we had
finished getting the PPA approved in 2007, the
summertime, there was a team dispatched to
assess what were the short list of projects
that could meet the possible load requirements
in the period near term to 2015 in that time.
And they worked for a year, and they gave us a
short list of the projects that met that test that 25 to 50 gigawatt hours of diesel displacement and could be built that that time period.

They looked at the practical options, the technically available options, what they might cost, whether they could be licenced in that time period. It was a form of cost benefit assessment relative to diesel, and that led to the short list that people were now working, Mayo B, Gladstone, Atlin, Marsh and the early days at looking at geothermal.

So large hydro is people at the corporation level asking themselves the question up to the board of directors one time further down, what happens in 2015? We better start looking about it. What is the best short list of project that we know of to be looking at projects. Maybe somebody should be assessing just that question.

So it's a form of cost benefit in my opinion, and it's a way of trying to assess what do we need? What are our options? What's the best thing we can do? And
what do we have to do now? As the project goes forward through each stage like Mayo B the analysis gets more and more to look like a cost benefit study of that project. And by the time it gets to a final decision of the board of directors, it's very definitely a full assessment of the risks, costs, and benefits.

Q Is there a cost --

A MR. OSLER: And all of this spending is effectively to do with what I was just discussing with all the management steps that go into it.

Q Well, is there a cost benefit analysis in whatever form you are choosing to suggest constitutes one? Is there a cost benefit analysis available you could produce for us?

A MR. OSLER: We have provided in response to YECL 5, and YECL I think 7, is it -- 8. The best and up-to-date analysis on the two lead projects that are in this area, and they would be Carmacks-Stewart Stage 2. The other projects we haven't provided anything more than the level of information we have, which is the type of energy we can produce and the type of timing that they might come on and
the statement that they are easily qualified to be effective if they can be developed. But the issue is not their economics. The issue is getting the licence in terms of Gladstone, Atlin, and Marsh Lake.

That's the best assessment, sir, that we have and we put them before the Board and the intervenors.

Q At this point I was talking about the studies. I wasn't actually talking about the project themselves. I was trying to find out whether you have done any cost benefit of this to justify the studies, and I thought you were maintaining you had done a form of cost benefit to justify the studies. And I am asking if you could produce that for us.

A MR. OSLER: What I have said is all on the record. There isn't a specific document, but there is the statement in the application and the answers that that's exactly what we went through, what Yukon Energy went through as a process to rationally focus on the studies of these particular projects that are being studied. You know, so you have got in front of you what we have available. But if it
was a rational process to assess options, look
at need and look at the short list of what
needs to be done.

The studies are the
assessed requirement to make the -- let the
selected project go the next step.

Q So if the Board or parties wanted to take a
look at what you are told the justification is
for spending sixteen-plus million bucks on
these studies, we have already got everything
on the record is what you are telling me?

A MR. OSLER: As I have said,
Madam Chair, the amount of money that we are
referring to, the 15, 16 million, ultimately is
that's very large amounts for Mayo B, and it's
going to go through some of key decisions
before that type of money is spent. It's got
some other planning costs for other projects
that will go through key decisions before it's
spent. We will answer any questions we can to
help demonstrate why these studies are prudent
and reasonable best ways to get to the next
step of each of the project.

Q All right, sir. Thank you, gentlemen.

MR. KEOUGH: I am ready to break for
lunch, Madam Chair.

THE CHAIR: Just before we break for lunch, Mr. Keough, can you give me an idea how long you might have for your cross?

MR. KEOUGH: Guesstimate an hour to an hour and a half.

THE CHAIR: Thank you very much. We will break for lunch and return around 1:30.

(PROCEEDINGS ADJOURNED AT 12:11 P.M.)

(PROCEEDINGS RESUMED AT 1:30 P.M.)

THE CHAIR: Please be seated.

I trust everybody got out for a little bit of sunshine.

So we'll hold you to your estimate, Mr. Keough. Are you prepared to proceed?

MR. KEOUGH: I am. I thought Mr. Landry was going to file the letter we were talking about.

THE CHAIR: Okay.

MR. LANDRY: Madam Chair, the letter that was referred to by Mr. Keough, the May 1st, 2009, letter to Yukon Electrical from Yukon Energy, if you want to mark that as the next exhibit for Yukon Energy. I will pass it
up, and we'll deal with it later, but get it onto the record.

THE CHAIR: I have B-13, so marked.

Exhibit Number B-13:
May 1, 2009 letter from Yukon Energy to Yukon Electrical.

THE CHAIR: Please proceed.

MR. KEOUGH: Thank you, Madam Chair.

Q MR. KEOUGH: Good afternoon, gentlemen.

I would like to just touch on a couple of areas, first one being brushing. And I wanted to refer you to page 3-8 of the application, as well as your response to YECL-YEC-1-53. And as I understand it, from your response to the information request, you do not have any written policies on brushing or line assessments?

A MR. MOLLARD: We're just pulling that response.

Q Sorry.

A MR. MOLLARD: Sorry, Mr. Keough, 53?

Q Fifty-three.

A MR. MOLLARD: Yes, that's correct.

Q And do you have any policies or procedures that
are not written?

A MR. MORRISON: Madam Chair -- are we okay now?

Just to help answer that question, in terms of not written, let me say it this way: We have a -- we have a practice or a standard when brushing. And it's changing a little bit, and it's a little hard to be as specific as we used to be. We had a rotational standard in terms of brushing the transmission grids, and -- if that's what we're talking about here. And I don't have it in my memory in terms of exact timelines, but we had a three-year timeline where we would brush, and based on our experience and our practice, we would say brush this half -- part of the Aishihik line or part of the Faro grid, and then we knew that that was a three-year rotation. By the time we were in that period coming back to that piece of line, it would require brushing again. That was based on experience and practice.

What we're finding with our brushing practices is that there may be global warming and there may be -- it may be
warmer in some regions, but it's been a lot wetter here. And because of this extra precipitation, we're finding that we've had to, in some areas, adjust as much as a year or two quicker to come back to these areas. Because with the wetter weather, what's happened is the brush has grown quicker, and it's required brushing on a more -- more often than we had in the past. So we still haven't quite got that nailed down in terms of a firm practice, but we're monitoring the lines on a more frequent basis, and we're brushing them more frequently because of the wetter weather. 

So it's a practice, I would say, rather than a policy or procedure.

Q And are you following any recommended industry practice, or is it more random than that, that you are just trying to keep an eye on the brushing situation, and you'll brush on an as-needed basis?

A MR. MORRISON: Madam Chair, the industry practice meaning we need to keep the brush -- we need the keep the lines, the transmission lines particularly, in a state where the growth around the line, in terms of trees, is kept to
a standard that wouldn’t harm the line. In other words, we don’t have a lot of trees or growth under the line or beside the line that’s going to impact the line. So to that utility standard, yes, if that’s what we’re talking about here.

Q And we note on page 3-8 that the brushing costs are increasing significantly year over year in relative terms for both transmission and distribution. To what do you attribute the cost increases?

A MR. MORRISON: Well, two things in terms of cost increases, and if Mr. Mollard has something he wishes to add. A) the part that I was talking about earlier, that we are having to brush more frequently on those lines, on both transmission and some of the distribution lines. And the costs of brushing have gone up as well over the period of time. So we’re getting a combination of both.

A MR. MOLLARD: And I could add to that that we do have our operational personnel survey the lines annually both from the air and the ground, so they have a pretty good handle on what ideas need attention, so to add to
Mr. Morrison's point on increasing, the areas
that need attention.

Q Do they provide a written report to yourself or
management on the areas that are going to need
brushing in the forthcoming year?

A MR. MOLLARD: I don't see anything in
writing, no.

Q And how do you come up with your estimate for
costs of brushing? I mean, is there a
tendering process? Is there a contractor you
use? Do you do it internally? I'm trying to
understand how you come up with your estimates
of costs?

A MR. MOLLARD: Our contracts are -- our
brushing is generally done by outside
contractors. The costs are we tender for those
contracts, so we know how much we're going to
be spending. The operations staff know it's
pretty set on a week with some variation for
terrain how much ground they can cover in a
week. So they'll know, based on their surveys,
how much ground they need to cover, and they
use that to multiply out time the weekly rate
for the brushers to come out with a budget
number.
Q Now, looking at your brushing program, I just wanted to sort of segue into a couple of questions on system reliability, if I might, and specifically your response to YECL-YEC-1-1 that deals with the number of outages.

And I also wanted to, in this regard, discuss with you the third aid to cross which I circulated, which is a newspaper article in which you, Mr. Morrison, are quoted. I am sure you are familiar with that?

A MR. MORRISON: Well, I have read it since you provided it, yes.

Q I am assuming you are familiar with it because you probably spoke the words as well.

A MR. MORRISON: Well, I've read it, yes.

Q And I would like to just understand a little bit about system reliability here. Am I correct that of the 35 outages you had last year, about 17 were what you are calling "controllable outages"?

A MR. MORRISON: Well, approximately, but I'd use the number 19 if I was using it.

Q Okay.

And about a third of the outages, or 30 percent of them, you are unable
to identify the cause?

A MR. MORRISON: Just to be clear, we're -- I'm not sure that we wouldn't -- "cause" might be the wrong word, and it would be the actual reason behind the actual outage happening.

We may know that it was on a certain piece of equipment, but in terms of the equipment, we may never be able to find out exactly what happened in that sequence of events to cause that problem. There are instances where that happens, yes, even though we bring in consultants and other electrical engineers to look at it, or mechanical engineers if it's a mechanical issue. Nobody can say for certain all of the time exactly what happened.

Q And if you can't identify the cause, it's pretty tough to take steps to rectify the cause so it won't happen again, correct?

A MR. MORRISON: Well, sometimes it is, and sometimes it's a process of trying certain things and trying to eliminate what the problem is.

Q And is that the strategy that YEC is utilizing
with regard to addressing reliability concerns, you just try something and hope it works?

A MR. MORRISON: Well, I don't think I said that, no.

Q Well, maybe you can enlighten me on what your strategy is, then, to try and improve on reliability.

A MR. MORRISON: Well, there's a number of front, and I think we've outlined them a number of times or in a number of the IRs. But let me talk about them for a minute.

We have done condition assessments on the transmission and generation assets. We have looked at -- from an engineering point of view, we have looked at the system and where we are having difficulties. There is a development of a capital plan by the engineering department and operations department. All of those are looking at the system based on building reliability.

And as we go through these processes, we have looked at the condition assessment of what we can and can't do.
We sometimes -- and we have had problems around things like the governor at Whitehorse 4. And it's probably a good example of trying to figuring out exactly what the problem was. We knew we had a governor failure, we had a governor failure several times on Whitehorse 4. We brought in numerous experts from BC Hydro, from engineering companies, from governor companies, and nobody could tell us exactly why we were having a problem. The problem was that it kept tripping.

We reset the PLC units, we developed a program so that we could program -- reprogram these units. We brought someone in from BC Hydro to do that. None of this could exactly get to what was causing the problem.

Fortunately for us, we have -- we have now been able to do that. We finally did find someone who was able to come up from a governor manufacturing company in the US and look at the system and say, Okay, we now, based on, you know, our chronology of events and what happened exactly, what -- this
is the problem; this is the solution.

And some of it was equipment related. You know, historically, the governors on those systems were older. They were a hodgepodge of a system. We've consolidated it to a single manufactured system now. It's fairly standard, and it looks like we've solved the problem.

So I would say to you that on all this -- all of these issues, we're looking at the system on a continual basis, we're looking at where we can make these improvements, and where we need to replace older equipment, and that would be the focus of our reliability efforts.

Q Now, in the article that I provided you that you have read, the bottom of page 2, the last sentence says (quoted):

"Morrison said while the WAF grid is old and in need of constant care...."

And, sir, do you recollect characterizing the system as being old and in need of constant care?

A MR. MORRISON: I wouldn't say that I said exactly those words. What I would have
said or what I recall saying is that the system is and the -- as an example, the Faro line, is, you know, my memory is bad, but 35-odd years old, in that neighbourhood. The Aishihik line is also in that neighbourhood; that's old, in my books. And because of those ages, we tend to find these days that we are spending more and more time checking the line, making sure that it's up to a state of operability that it will meet the reliability standards that we have.

Q And, sir, back up in the top third of that page, or about just over a third of the way down, it says (quoted):

"In the last three years, Yukon Energy has spent approximately $8 million annually maintaining and upgrading the system...."

Do you see that, sir?

A MR. MORRISON: Yes, I do.

Q Sir, would that $8 million have gone towards projects that were designed to maintain the reliability of the system at an acceptable level?

A MR. MORRISON: Some of that money would
Q And I guess the point is, in your view, has Yukon Energy spent adequate money to ensure the system is at an adequate level of reliability?

A MR. MORRISON: Well, I think, you know, we can always spend more money. That's not always the issue with us. It's what we can spend and get done in a -- either a construction season or over the period of a year. And we can't spend all the money in one year because we can't have all of the equipment out of service or we can't do all of the things we want to do because we have to do certain things in certain order.

So the money that we have been spending is very important that we spent it in those years. Some of this work builds on other work that we do each year. And I think where we felt very strongly that we needed to do was we needed to look at a whole -- not just a one year, of we're going to spend this money this year and solve all the problems. That's not the case. We can't do that.

It's an old system. The two hydro plants are 52 and 50 years old.
There's a whole series of work that we need to do each year to make sure that we can keep the plant both operating and operating in a reliable manner. So we try to look at what can we do this year and what can we do next year. And some of the circumstances change, so we adjust to that.

But all of this is a build from one year to the next. We can't just say, We have got some reliability issues; let's spend $30 million in one year. A) we can't physically do it, and B) it's not, from an engineering or project management point of view, you can't do all of these things all at the same time.

Q But you are telling us that notwithstanding the number of outages that you have experienced, it YEC's position that it did indeed spend adequate funds to maintain an acceptable level of reliability on the system?

A MR. MORRISON: Yes. What I'm telling you is we needed to spend that money to get improvements on reliability. And what also, I think I was saying, is there isn't a magic wand where we just spend a certain amount of money
one year and we solve every problem.

It's a big system, at
least big for us. Maybe not big in comparison
to other places, but big for us, big for the
size of utility that we are. So there's a
certain amount of work we can do every year,
and the objective is to get a reliability level
that's a lot more acceptable than the one that
we have been experiencing, but it's going to
take some time. And even when we get there, it
isn't going to stop. We're going to have to
keep spending money and keep, you know, a
fairly diligent effort in terms of how we solve
the -- or how we maintain the reliability
levels we need to maintain.

Q So I'm just trying to be clear on what you are
saying, because I'm sort of hearing two
different things that are slightly different,
in my mind anyway.

The level of reliability,
number of outages over the past number of
years, has been at an unacceptable level; is
that your view?

A MR. MORRISON: In my mind, yes.

Q But, nonetheless, you have been spending what
you consider to be adequate funds over those
past years to maintain an acceptable level of
reliability?

A MR. MORRISON: I'm trying to -- what I
am saying is that we have been spending as much
as we -- or doing as much work as we could do,
possibly do, in those years to try to work
some -- to improve reliability and work through
the projects that we had on our books.

Q Did you have any process or management process
in place where you scrutinized and prioritized
the projects so that you target ones that were
designed to improve reliability if you were to
perform them during the year?

A MR. MORRISON: Well, we have a -- when
we do our capital plan, Madam Chair, we outline
in a priority order the projects that have to
be done. We classify them under different
categories for different reasons.

I mean, there are certain
ones that we have to do because as -- let me
put it to you this way: They are mandated
projects by some regulator. I'll give you an
example, is we have to do a certain amount of
work on the Aishihik watershed every year to
meet the terms of the water licence. It's a capital project.

So there's a series of projects that fit into that category. There is a series of projects that fit into reliability. There is a series that will fit into the category, you know, around system enhancement. So, yes, we do prioritize and categorize our projects in our capital planning process.

Q Could I just move on to a couple of questions about the hearing cost reserve issue, and I am looking as well at your response to YECL-YEC-1-28 REVISED.

And I think this was updated as part of your April 24 filing as well. If you have those references, I will add another one to it because I have just found it; it's page A3 and A4 of the update, being Exhibit B-10, the April 24, '09 update.

And I just want to understand. Like, currently you are proposing or suggesting that your estimate for the hearing costs will have gone from 800,000 to 1.1 million?

A MR. MOLLARD: That's correct.
Q And that is primarily because this case has
been more complex than you figured; is that --

A MR. MOLLARD: We did experience
significantly more IRs than we had planned on
having to deal with.

Q And as I understand your proposal now, it is to
amortize that amount over three years, '8, '9,
and '10, as 400, 400, and 300,000 respectively?

A MR. BOWMAN: Well, Mr. Keough, without
being too specific on the point, the updates,
page 84, estimated the hearing costs at
1.1 million, but of course they will be what
they will be, depending on the Board's orders
out of this hearing. So in order to help make
sure we could put together a revenue
requirement that could be known and could test
and know what the rates will arise from it, we
determined that it made sense to retain the
amortization at $400,000 a year until such time
as the amounts are amortized.

If the costs the Board
approves for the hearing are less than what is
set out here or the costs go higher than what
is set out here, it will take less time or more
time to amortize those costs off.
At this point, based on 1.1, it would take years at 400,000, and the third year there would only be 300,000 left remaining to amortize off.

Q I understand that, and fair enough. I am just trying to confirm your understanding of how this hearing cost reserve would work and whether or not it's, in your view, different than maybe other reserves.

Would you, or would YEC, propose to make a provision of the 400,000 in the reserve each year even after 2009 so the reserve would continue to accumulate the 400,000 into the future, or would the reserve end after 2009 or '10?

A MR. BOWMAN: Well, Mr. Keough, I'm having recollections of a very similar discussion in 2005 at that hearing in regards to hearing costs on basically the same issue. And the answer is -- is the same as it was then: Yukon Energy incurs hearing costs, amortizes them over a period or at a rate approved by this Board, and when there is no cost left to amortize, the amortizations stop. The same as amortized costs, if you go to
tables, the ones we were at earlier today, 5.2 to 5.7, we have a study and we amortize it over five years, at the end of the fifth year, there is nothing left to amortize; it stops. The same as these others, and others come in to replace it.

It's a simple amortized cost, the same way as any other deferred cost in the cost structure.

Q  It is not a reserve similar to the reserve for injuries and damages, where a provision is made each year and continues throughout the non -- a nonetest-year period?

A  MR. BOWMAN: That's correct. It's not like that. It's never been.

Q  Right.

And so if your approach is approved, the existing rates that are established will result in customers paying the 400,000 in 2010 and 2011, if those are not test years, correct?

A  MR. BOWMAN: Well, again, this is -- the questions that we dealt with in 2005, and again the answers are the same. 2010's costs will be what 2010's costs will be. At that
time the forecast for 2008 or 2009 will not be
the same.

I think Mr. Morrison laid
out earlier on brushing, they will be brushing
a different section of line or brushing will be
down and something else will be up. The costs
change over time. Rate reviews deal with the
years in question, and in this regard, the end
of amortizing your GRA costs is the same as
amortizing any of these other studies you will
see ending in Table 5.7.

Q So, basically, you are not asking for a
reserve, you are just asking for an
amortization; is that the difference?

A MR. BOWMAN: This application does not
seek approval to do anything different than has
been in the past. GRA costs amortized over the
period it takes to amortize them off, given a
rate of $400,000 a year.

Q And you would agree with me that if one were to
look at a reserve like the reserve for injuries
and damages, in that case the Board approves an
appropriation each year, and it accumulates and
gets adjusted at the time of the subsequent
rate application, GRA?
A MR. BOWMAN: Well, the way the reserve for injuries and damages works is there is a standard annual appropriation, which occurs for the period of the time that the Board sets rates until the next GRA. We had a bit of a unique situation in the last GRA, since the Board approved a bump-up to the reserves amortization for three year, '05, '06, and '07, at which time it was to drop back to the old level. But there is an amount every year that goes to the reserve. There is charges to the reserve at any given year where you have events, tends to be at least one every year, and the reserve is trued-up at a later date.

Q I would like to turn to Section 5 of the application now, and I would like to chat with you about some of the capital projects that are included therein, as well as some of the associated information responses that you have provided to Yukon Electrical.

And I am looking at page 5-1 at the start. Now, I think we may have clarified this this morning, but I just want to be on the same page with you. You make reference on lines 23 to 24 about certain
capital projects having been previously reviewed by the Board, correct?

A  MR. OSLER: Yes.

Q  But you are not suggesting there that that review in any way, shape, or form authorized YEC to go ahead with any of these projects, right?

A  MR. OSLER: To go back over this conversation this morning, the Board in the sense that I think you are using the word, doesn't have a statutory authority to authorize either utility to do a capital project. What it -- what we did intend with the resource plan was that we would have honoured the commitment that the company made to find a way to get projects more than $3 million, before the Board before they were finally committed, for the Board's review and recommendations. And that's the best we can do under the statutory framework in Yukon.

So we did intend that that be done, and that would be the Board's review on matters such as the ones we were talking about this morning, the need of the options and the prudence of going forward.
The issue of how prudently the project was executed and everything else are matters that come up in a rate case.

Q All right, sir.

Now, if I could just flip over to page 5-3, where we are talking about a number of specific projects. And about line 8 we are talking about the Carmacks-Stewart transmission project, the 38.383 million; do you see that?

A MR. OSLER: Yes.

Q And there's a contribution of some 34.6 million.

A MR. OSLER: Yes.

Q What was the original forecast cost for this project?

A MR. MORRISON: Well, Madam Chair, I'm not sure how to interpret the word "original," but let me talk about --

Q Initial, first.

A MR. MORRISON: Let me try to answer the question the best way I can.

When we look at a project, we start very early on in the project
stage, including Carmacks-Stewart, and we did, with very little -- with little information, put together what we thought were numbers. But we were in front of this Board on the Carmacks-Stewart project, and what we explained was that as a go-forward basis for the project, and we can start with a number today with very little information.

But what we did was we kept building on both our engineering information, our design information, our regulatory information. And when we decided to proceed with this project, that we would not proceed with the project prior to getting our Board approval. And we wouldn't do that without having tendered construction costs available to us so that we would know exactly what the cost of the project was, rather than try to come up with a very early number and try to suggest to people that that was a number that was something we could hang our hat on and justify. And that's not how the process works.

So with tendered numbers, tendered information, and a very high level of engineering information in front of us, we were
able to say to our board that the cost of the Carmacks-Stewart line was going to be, and I'm just -- if you give me a second, because I want to get the right number -- was, on the main spur -- on the main line, $27.8 million, and on the spur line, 8.8, for a total of $36.6 million.

And the cost of the project came in within a few hundred thousand dollars on the main line of the number we started out with.

If we take out of that number the requirement that we got from the YESAB process to reroute the Tatchun -- location of the line at the Tatchun Creek, and that requirement that we came out of the YESAB process with cost us $1.9 million -- sorry, $1.8 million.

And other than that we were within a few hundred thousand dollars of our budget on the cost of the line. But what was the -- I wouldn't be satisfied saying to anyone that we had a cost for that project until it was a cost approved by our Board.

Q Sir, I'm not sure in that lengthy response you
answered my question.

A MR. MORRISON: Okay. I'm sorry. If you want to repeat it, I will try again.

Q Yes, sir, I will.

I asked you what was YEC's original or initial cost estimate for the project.

A MR. MORRISON: When we were in front of this Board, Madam Chair, and I'll ask my colleagues to give me the numbers, but I believe it was a range between 22 and 25 million.

Q Anybody else?

A MR. MORRISON: No, no, that's the number. I just had to look at it.

Q And the 38-plus million, is that your current estimate?

A MR. MORRISON: No, that is the final cost.

Q The final cost?

A MR. OSLER: Of the --

A MR. MORRISON: Of the total line, the spur and main line. And the spur line is -- sorry, go ahead.

A MR. OSLER: Let's be really careful
here. I thought the question started off looking at Carmacks-Stewart line, and the answer was that the original amount in the resource plan hearing was 22.6 million cost estimate, and there was a range.

The final cost of that line is 29.7 million, in round numbers, including the Tatchun reroute, which is 1.8 million. Absent the Tatchun reroute it's 27.9 million. So the record will show that that's the numbers between the first time anybody saw any estimates back in the resource plan, which had no preliminary engineering, as we explained to the Board at the time, and the final numbers that came in.

The board of directors of Yukon Energy approved a cost, which had tenders for most items, but not substations, in September of 2007, in round numbers, of 27.8 million. Mr. Morrison's referring to the performance of the project relative to the cost approved by the board of directors at that time, which was preknowledge of the YESAB's final decisions on the Tatchun reroute.

Q With regard to the spur line -- you gave me the
numbers for the main line. How did the numbers for the spur line go, the original to the final?

A MR. OSLER: Using the same information, and that's the time we were before the Board, in the resource plan and the time that the PPA was approved, signed, let alone approved, the number was 3.8 million, in round numbers. The final cost number, including any changes made by YESAB, is 10.8 million, as set out in LE-47.

Q What were the main --

A MR. OSLER: The board of directors approved a cost in September of '07, based on tendered line construction, but still the substations had not been tendered, of $8.8 million. And Minto, of course, is paying all of the spur costs.

Q And what were the main reasons for the significant cost variance between what was put forward in the resource plan and what was approved by the board of directors?

A MR. MORRISON: The -- well, so Madam Chair, the --

A MR. OSLER: Resource plan -- just to
set the stage, resource plan, we had no
engineering and final estimates.

A MR. MORRISON: Okay. Madam Chair, and
that's where I want to be clear here. Two
separate issues from the -- I think we have to
look at.

When we came to the
resource plan hearing, we had a number. And we
talked about those numbers, we had a range for
the main line and the spur line. And, again,
it's this -- to go back to what I was talking
about earlier about when in a process do you
have numbers that are really very preliminary
estimates versus very concrete information or
concrete numbers that you can rely on in terms
of contracting a project and going ahead.

And in the resource plan
process, our -- the information we had on the
spur line was very, very preliminary. And I
believe there was an assumption made at that
time that the cost of a smaller line, in terms
of the line and the poles, was going to be
significantly different than the cost of the
main line, which is a larger conductor, 138
versus 25, and poles and so on and so forth.
We also didn't have very much information on the substation costs at that time because we hadn't been able to tender them.

So as we build our information and we build our ability to get better and better costs, these numbers got refined. The big cost difference -- and as I have already talked about, if we look at the main line is, we were able to keep that main line cost very constant to what our approved numbers were as we went from a board -- our board-approved project to the completion of that project.

We were really close, other than the regulatory realignment of the route, which cost us a fixed amount of money, and there wasn't anything we could do about it. The route had to be changed, and we had to pay the cost of that. And it was done while the project was underway, and it was a very, very, very difficult piece of ground to work on.

I don't know if people will remember, but we went from ground that was accessible by some vehicle, tract or otherwise,
to ground that every pole we put in was put in with a helicopter. So the crew had to be helicoptered in every day, all the equipment had to be helicoptered in, all of the nine-foot diameter holes for the poles had to be done by hand.

All of these things and the amount of helicopter time, even in our original thought, was significantly higher in order to do this. So we incurred this $1.8 million cost overrun.

On the spur line the big cost that we couldn't control -- and we're building this probably in terms of Canada, and perhaps North America, you know, at project levels and pricing levels, we're building at a time in Canada where you couldn't get contractors, you couldn't get men and equipment. The price of materials went out of sight, and it was a substation cost that drove it from what we thought was $8 million to $10 million.

Q What I'm struggling with is you appear now to be distancing yourself from the validity of the numbers in the resource plan, but on other
occasions we have discussed today, the resource plan appears to be a very strong document that you are relying upon, because you are saying this Board examined these projects at that point. But now you are basically saying the projects are quite different, the costs are quite different, and the resource plan was preliminary. I am struggling to reconcile those two positions.

A MR. MORRISON: Madam Chair, I hope I haven't confused anything that way.

All I am talking about today is in the resource plan, when we talked about those projects, we had a certain amount of information, and we based the information we provided to the Board on what we understood those costs were to be, based on the preliminary stage they were at.

But when you look at a project, you can't just go outside and look at something and say, You know, we think it's going to cost X because we had a contractor come down here and look at it. These are very significant projects.

We refine the project as
we go forward based on the information we can
develop, and I think that's a big part of where
the difference is. I'm just trying to explain
that, not the fact that we didn't think the
numbers we had at the time were right.

They were very good
numbers based on the information and the state
of the project at that point in time, but they
devolve.

And Mr. Osler has a point
he'd like to make.

A  MR. OSLER: It underlines probably
everything we were talking about earlier. The
difference between the numbers that we had
before the Board in the resource plan, the PPA,
and the Part 3 hearing, and the numbers the
board of directors had around June of 2007 was
that there was preliminary engineering that
cost whatever it cost, but it wasn't cheap. It
had been carried out.

YEC, in its wisdom, did
not want to undertake those commitments for
that preliminary engineering until it had a
PPA. It did not engage the engineer until
March of '07, didn't put out a tender for that
engineering until January or early February of '07, and the result was the information couldn't be available any faster than it was.

    For all the other reasons, nobody could put that information in front of the bodies we were reviewing because it wasn't available. As soon as that information was available, the cost estimates for the projects we're talking about was materially increased.

    The Board here and Mr. Morrison and I had a discussion at the very end of the Parts 3 hearing about the range of the possible costs, the 20 percent higher than midpoint, and how much higher could it go? The point of our investigation at that point in time is, How much latitude does this project have and still be -- have no adverse effect on ratepayers.

    And we didn't answer forthrightly, I guess, the question about how high could the costs go before the project wasn't for sure a project anymore. And it's right at the very end of the transcript of the cross-examination -- Board's questions of us.
But we knew that it was a lot more than 20 percent. And it would still make a very good project for ratepayers.

I can tell you, Mr. Morrison can tell you, how happy his board of directors was when the preliminary engineering came in, and we went over the whole thing for two weeks in terms of is this project still viable or not, because it's more than 25 percent -- about 20 percent above the cost estimates we were working on.

But we took a deep breath and looked at the benefits to ratepayers and all that stuff, and Mr. Morrison talked with Minto, and they took a deep breath, and everybody said, This is still a good project. We don't like the numbers, but it's still a very, very good project.

And from that point forward, having spent that money on preliminary engineering, but only after certain things had been achieved, the parties then waited to see what the bidding -- what the actual tenders would be. The tenders came in very well on line work relative to the engineering, the
substation tenders were much higher. This project did not have a major substation component in terms of its overall costs.

The board of directors elected in September, for all the reasons you can understand about schedule, to go forward and commit the project, subject to the final permits from YESAB, in September, based on the line construction tenders, without having the substation tenders yet.

When the substation tendering was finally done in the spring of the next year, it was clear that there were material cost increases there compared to what the engineers had estimated. There was also the issue of the final changes that came from the final permitting.

Yukon Energy didn't incorporate those changes. We thought we had a fighting chance of getting them not incorporated, because of all the arguments that were put before the utility board and position bodies, before the YESAB, but, you know, in the end, they were the changes -- they were the requirements for the project to go forward.
So it is a classic example of risk, cost. Information costs money to get, when do you get it. If we had spent the money on the preliminary engineering before we came to the Board and resource plan, we would have had better information. But if the Board hadn't liked the project, we would be asking ratepayers to eat another million dollars. And that was not the decision we made then.

And if people think it would be a better approach in the future, then we can consider the alternatives. But it is a classic example of what we were talking about earlier today, risk management.

Q You mentioned the substation costs a few times. How many substations were included in the original design?

A MR. OSLER: The original permit, the original project as set forward for Stage 1, talked to a substation or switching stations at Carmacks, Minto Landing, and Pelly. The final project as executed, and frankly as planned about June of '07, given the costs, was switching facilities of some type at Carmacks,
that I'd let others describe, a materials
substation at Minto Landing, and deferral of
the substation or methodology for connecting
Pelly, so that the line was built from
Minto Landing to Pelly at 138 kV, but it's only
energized at 25.

Q So if the original number of substations had
actually been built, the costs would have been
higher; would that follow?

A MR. OSLER: That would follow.

Q All right.

Now, when you a moment
ago talked about the benefits of the project
again, are we talking of benefits in the
context we did this morning, benefits taking
into account the government contribution?

A MR. OSLER: Yes.

Q Could I get you to look at page 5-7. And I
just had a couple of questions on the Minto
diesel units over to 5-8.

What type of due
diligence did YEC conduct into the condition
and the value of these units before purchasing
them?

A MR. MORRISON: Well, Madam Chair, in
that power purchase agreement, there is a set of paragraphs around what the conditions were around how we would go forward in terms of purchasing. And the part of that, and I believe my colleagues, I'm sure, can refer people to the proper IR number, but we did talk about this, is that they were -- the units had to -- we had to look at how many hours they had. They also had to have, I believe, a 12,000-hour overall, which is part of a standard diesel unit package. They are busy trying to find the number, but I'll keep talking.

And so those conditions that were outlined in the power purchase agreement, which was reviewed, were the -- were the -- were carried out or have been carried out by us, as my understanding, is all the work that has been done or is just about to be finished being done by Minto.

Q And was the price based on net book value or fair market value, replacement value, or some --

A MR. MORRISON: Maybe Mr. Osler can help me on the price, but the price was a negotiated
price.

A MR. OSLER: Not -- the original price that was in the PPA approved was based on original cost less some provisions for the fact that they weren't going to be new, with extra provisions in the agreement to deal with what overalls they would have had to have executed, and the implications in terms of reduction of price if they haven't, and depending how many hours were on each machine.

It was also cross-checked against the alternative costs that the company was aware of for other machines of a similar type at that time, and the price was resolved on that basis. And the -- the requirements in the PPA, referring to PWP-21, has some of the review of these matters.

But the requirements in the PPA for Yukon Energy to be satisfied at the condition of the machines is in the PPA. It's in the article on diesel units.

Q Has that condition been satisfied?

A MR. MORRISON: Madam Chair, perhaps if we can -- Mr. Osler said, we can refer people to PWP-HML-YEC-1-21.
And the conditions outlined there, as I indicated, there is a minor or top-end overall on units with 8,000 hours of operation. And then for units with 16,000 hours of operation or more, a major overall, in accordance with the manufacturer recommendations.

So what I can tell you is this: three of the four units had a minor, or 8,000-hour overhaul, and completed -- and that's been completed. And none of the units is approaching the 16,000-hour threshold.

A MR. OSLER: And I just would say that the units, at this moment, are still not -- have not been assigned to YEC. The primary ration -- reason for that, as I understand it, is relating to the environmental permits that Minto had for the units, and the issue that what we have to do for YEC to be able to take over the units.

It's not related, I am advised, to issues of concern about the quality of units. But I can't -- I cannot tell you that to date YEC has signed off on all of the items.
The primary reason being it's going to take a bit more time to get the environmental permits in place that will allow Minto to be able to give the assigned units.

A  MR. MORRISON: Let me be clear, Madam Chair. We can't operate the units without a diesel emissions permit that YEC holds. And we have been in the process of getting that permit since early last fall or late last summer. And we expected that we will have that permit any day. We have been -- we are -- excuse me, maybe not any day, but soon, because it -- I shouldn't talk, you know, in those kinds of terms. There's no -- you know, there's a process, and we have to finish the process.

But once we get a permit to operate those diesels and we have -- we can't -- we can't have those diesels transferred to our possession until that happens, and that's the condition that we are trying to fulfill at the moment.

Q  Now, on page 5-8 of the application, around lines 11 to 13, there is a discussion of Board Order 2007-5 and the requirement for a
demonstration of need and a business case
supporting the option to purchase.

Can you identify for me
where that business case and demonstration of
need is located? Is it meant to be satisfied
in the text that follows?

A  MR. OSLER: Yes. The need issue is
addressed in page 5-10. The economics issue is
addressed in pages 5-8, 5-9, and some
additional factors contributing to the
assessment are listed at the top of page 5-11.

Some of it -- in summary,
the need for the units is based around the
capacity requirements of the system and where
we are in meeting those. And the point is made
at line 17 to 24 on page 5-10 that there is
indeed a need for these particular diesel units
at this point in time and that electing to go
with these units gives us flexibility in the
timing that we spend money on some other units
in Whitehorse, and so we just simply delay
their funding and upgrading or refurbishment
until such time as they would be needed to meet
the capacity requirements that we were talking
about earlier, capacity peak winter.
In terms of the cost issue the Board had raised concerns about, pages 5-8 and 5-9 address the comparability of meeting this capacity need for peak winter reliability based on the options that the company has.

And, in summary, with all of the upgrades and putting in SCADA and other things that would be needed to have these units be an effective part of the Yukon Energy Whitehorse-Aishihik-Faro system, the cost is about .498 million, it says in line 8 at page 5-9, and that is shown to be competitive with the Whitehorse Mirrlees units, which at line 27 is shown at .482 million per megawatt in each case.

So our understanding is that, and I'm summarizing, that the need and the cost efficiency are addressed. There are other issues that we think are relevant, and they are listed in page 5-11. They are near a major load, and in that sense, two of the three units, as we have said in other testimony, would rank next to the top in the diesel generation stacking order, so that
having these units close to a load when we need
to operate the units is, we think, certain
benefits to the operation of the system.

They could be run without
an emissions impact in Whitehorse. We are not
saying an emissions impact in Whitehorse, in
our opinion, is a major issue from the point of
view of meeting the requirements of the
environmental permits and everything else, but
we are well aware that several people in
Whitehorse have said that they are concerned
about those things.

And in the near term
units, provide a cost-effective contingency
protection in the event that we have other
mines develop in the area who will not have
on-site diesel to the same degree as this mine,
we have extra contingency in the area.

The four -- some of the
units we have to hold for, I think, two years,
and the balance -- at that time we have
flexibility in dealing with them. The balance
of the units probably would be there for quite
a long time period, unless Minto wants to take
them over.
Q A couple of follow-up points, if I might.
   You said that the units
   are located near a major load. That would be
   the Minto mine itself --
A MR. OSLER: Yes.

Q They are not near Whitehorse?
A MR. OSLER: No. It's a 30-gigawatt
   hour load, which is not trivial, and it's going
   to grow to be bigger. So it's -- relative to
   the size of the diesels and everything else,
   it's a material load.

Q Right. But they were located near that load
   when they were owned by Minto, right?
A MR. OSLER: Correct, but once we hook
   up Minto through the PPA, we have to serve --
   that becomes our load.

Q Right.
   Now, the -- you mentioned
   in your comments about the flexibility. I
   think you were talking about the flexibility to
   move these units. And I was looking at
   page 5-9, Footnote Number 9. There are certain
   restrictions on YEC's ability to move those
   units?
A MR. MORRISON: Yes, there are. Those
restrictions are outlined in the power purchase agreement.

Q Does that constrain or reduce the usefulness of the units in terms of supporting the grid as a whole?

A MR. MORRISON: Madam Chair, no, I think -- no, it's doesn't, just to be clear. What Mr. Osler was trying to get at is, you know, we're starting to stretch line distances from the core or the centre of the generation, so we have got Whitehorse, we've got a generation -- big generation load capacity here, and we're going a fair distance now when we start talking about length of line towards Minto. And from the operability of the system, it's very, very helpful and very functional for us to have a generating source out towards the end of that long string, that long line, so that we can manage the balance in the system itself.

So actually having those there, as Mr. Osler said, is a real benefit for us. Whether or not in the future we may move one of those or two of those, you know, would be issues that we would look at in terms of the
operation that we need in the area. But I
don't see as, at least at the moment, moving
the majority of those units any time in the
near future, unless there's no mine there,
which we would then have to rethink.

But it's very beneficial,
from an operability point of view, to have
those units in that area.

A MR. OSLER: The flexibility comment,
just to be clear, relates to what Mr. Morrison
just said at the end as well. Some day the
assumption is there will not be a mine there.
And if by chance there is still a couple units
there, they are not locked down the same way we
have had the issue in some other locations. So
that flexibility was judged to be not decisive
but worth noting from the point of view of an
assessment.

Q All right.

On page 5-9 there is a
discussion of the Whitehorse Mirrlees, and I
just wanted to chat about those for a moment.

I'm trying to understand
the rational that YEC went through to conclude
that these were a deal, if you will, in terms
of the costs. Am I correct that what you are doing is you take the cost, and you spread it over the number of what megawatts and the number of years that you forecast they will be operated, and you then come up with a dollar per megawatt number using that math?

A MR. MORRISON: Madam Chair, I am going to let Mr. Bowman do the math because he is a lot better at it than I am.

But, generally, what we did is we looked at what -- we have -- we have a capacity planning criteria that we have reviewed here with the Board. When we look at that capacity planning criteria, we need the -- we need so many megawatts of capacity to back up the system. So in part of that analysis, we -- these units, and there are three 35-year-old Mirrlees in the Whitehorse plant and where we started this analysis.

And if we took those out of service because they were at an age where they should come out or be retired or they could be retired and we had to replace it, we came up with a cost for replacing those units. And let's just say, in round numbers, it is
5 megawatts, and it would be about nearly $6 million for those megawatts, about 1.1 or $1.2 million per megawatt is my recollection. I have recollections; he has real numbers.

So when we looked at that, then we looked at what it would cost us to refurbish those units. And I think we had a very lengthy discussion here in front of this Board about the benefits of doing the refurbishment over providing new units at a higher cost, a substantially higher cost, considering that they were backup. They are backup units. They are there to provide capacity. And hopefully we don't run them, and if we do run them, we run them very little.

So that's the general genesis of what I was talking about, but Mr. Bowman might add some of his -- some of his number skills.

A MR. BOWMAN: I'm not sure what else specifically to add in terms of numbers. I would just note that the -- from an economics type of analysis, what the resource plan was working on was establishing, in the first instance, that there was a need for capacity,
as Mr. Morrison said.

So that once that is known, the question comes down to, What is the alternative to get that capacity? You know you have to do something, it is just what are the costs of the different ways to do it.

At that time the Mirrlees was -- when we first filed the resource plan, the Mirrlees option related to 14 megawatts of generation at Whitehorse, three units, two 5 megawatt units and a 4 megawatt unit, and an estimated cost in the resource plan that's a number I won't recall from the original document, but there was an update done to it which noted that there was actually even a further 5 megawatts related to the Mirrlees unit at Faro. So we are talking about a total of 19 potential megawatts.

And by the time we got to the resource plan hearing, the numbers that people were working with was approximately $5 million, in 2005 dollars, to do the Mirrlees at Whitehorse. And on top of that, another 1.4 million that was common systems related to the entire diesel plant, some seismic, upgrades
to the building, and dealing with some
air-handling issues, for example. And a
further 2.3 million at Faro. These were the
numbers that we ran.

So when you put all of
that together, it comes to 8.7 million for
19 megawatts. It was just under half a million
a megawatt in 2005 dollars.

That was confirmed in the
resource plan to be the cheapest option
available to Yukon Energy, and it offered some
benefits in terms of flexibility and the like.

We -- when you're dealing
with the numbers in this filing that you are
dealing with, at page 5-9, what it's got now,
that Mr. Osler would know, is a lot better
numbers, after a lot more work, related to
these units.

In the resource plan
hearing, the numbers I just went through, that
led to 8.7 million, we did a further
sensitivity that said, What if it came in
$5 million higher than that? What if we really
missed the mark? Because we knew that there
was a lot of uncertainty, 35-year-old units
taken apart, you are not quite sure what you
will find inside. And it was still a good
project, even at that upper level.

What we now know, based
on what's here, and what's underway, units that
have been taken apart and basically a few of
them put back together, or close there to, is
that we are on track for the lower cost
estimate that we went through the resource
plan, approximately half a million a megawatt,
still holding at approximately that level, for
the Mirrlees that are being done. And that
includes costs all the way out to 2012, as they
are all done in an orderly sequence.

Given that we had set
that benchmark, that this was the lowest cost
way to get that capacity, half a million a
megawatt, the Minto diesels were always viewed
against that best alternative. So when the
Minto diesels can come in as a key component of
the PPA, or acquired component of the PPA, to
bring on line the capacity at effectively the
same price, and offer these additional benefits
that Mr. Osler noted, like flexibility and
ambitions and being close to load, for example,
they, if anything, matched, if not had a leg up, on the Mirrlees. And I guess in that regard my comment on the movement or flexibility is -- it's not absolute. You can't move them any day you want, but they are a lot more movable than a Mirrlees is.

So when you are comparing the Mirrlees benchmark, that's where the diesel has got to leg up, and that's why they end up being a useful acquisition. So I think that may deal with the numbers that you were using.

Q Now, you talked about the current cost estimate being in line with what was forecast. And have the units actually been refurbished, and are there any of them up and running, so to speak, in their backup capacity?

A MR. MORRISON: No, Madam Chair. The unit -- I mean to be very clear. Units are in the process of being refurbished. The Faro unit, while we started it before the Whitehorse unit, we changed plans partway through. And with the Whitehorse unit, I would say is a week or two away from being operable. So it's very, very close.

What we've done through
this process as well, is we have been able to
refine our process and systems on how we can
deal with these subsequent units, these
Mirrlees. You will recall that when we
discussed these -- whether or not to do these
units at the previous hearing, we talked about
the big issue, from our perspective, was, as
Mr. Osler noted, A) when we opened them up, are
there big surprises, because they are very big
units; they don't move. And B) could we
continue to get the parts?

So we have solved, and I
think discovered, two things that I think are
informative and, as Mr. Bowman mentioned, will
keep our costs down to these lower levels.
One, we've found that through some -- you know,
some process, and it wasn't always an easy
process, that we can get the parts, and that
probably the original equipment manufacturer is
the best source of the parts, even though
they -- you know, they don't have as big an
operation in Canada as they used to have, we
still seem to be able to get the parts and get
them in a fairly timely manner.

The second one in the
process that we discovered that we have an
unlikely source of assistance in Western Canada
for helping us with these Mirrlees, and that is
BC Ferries. And BC Ferries are run on Mirrlees
engines. Not all of them, but they certainly
have a very large fleet of Mirrlees within the
BC ferry operation. They also have a very,
very large and comprehensive cadre of qualified
Mirrlees mechanics and experts, because they
fix these engines all year long.

And, in fact, they are
the ones that have done the overall of WD3, the
Whitehorse Mirrlees. So we contracted with
them; they set up a crew; they have done the
work. It's worked out -- from my perspective,
it's worked very well. It's economic; it's
well within budget. As a matter of fact, it is
probably going to be a little bit under budget
that we set. And they will finish the Faro
unit for us as well.

So we have been able to
find -- solve some of the issues that we
thought we might be faced with during the last
time we discussed them, and they're coming in,
as Mr. Bowman indicated, you know, at the lower
end of the range.

Q Gentlemen, just to confirm, the analysis that you did was, as we discussed previously, in terms of deriving a comparable per-megawatt cost, but there wasn't a stand-alone cost benefit analysis done of this project?

A MR. OSLER: Before I make -- that -- we have described to the Board what we did. The Board knows because it was here. I don't know what a stand-alone cost benefit would mean in the context of the time we were before the Board trying to justify going ahead with this in light of the options.

It's several projects too, in the sense that the decisions that have to be made are made separately for the Faro unit and each one of the Whitehorse units, so there are some synergies in Whitehorse.

So I think we have described a process of rigorously going through and assessing the costs, the options, the benefit of this choice rather than that one, trying to make sure we thought of all the choices, and then all the risks, because the numbers are always subject to risk. You just
repeated them all over again, and we've just seen, in a learning sense, what happens, since the last time we were before the Board, and in this particular instance, the risks have been managed and people were very happy with the outcome, both with respect to part supplies and the actual business of getting the job done.

I guess the one thing that's been frustrating is it's taken time to get that learning. It's probably driven some management people to distraction at times. But that's the biggest cost is management being driven to distraction; it isn't ratepayer cost.

Q All right. Maybe we can move on.

I am going to talk to you a little bit about a couple of the revised information responses you provided to Yukon Electrical. The first being YECL-YEC-1-5 REVISED, and I am looking at page 2 of 12, Part B of that question. This is on Mayo B.

My first question --

A MR. MORRISON: Madam Chair, could you please give us a minute; we are just not quite there.
Q  Sorry.
A  MR. OSLER:  I am just having trouble
finding it, sir.
A  Sorry.
A  MR. MORRISON:  Madam Chair, we are
ready.
THE CHAIR:  Please proceed,
Mr. Keough.
MR. KEOUGH:  Thank you, Madam Chair.
Q  MR. KEOUGH:  My first question,
actually, is on the footnote on page 3 of 12.
And I am trying to understand if I am reading
the footnote correctly. Is it YEC's position
that the Mayo B project is dependent upon the
Carmacks-Stewart transmission line Phase II?
A  MR. OSLER:  We think that the --
under normal circumstances we would say that to
make this project viable, you would need the
Carmacks-Stewart line completed because the
project provides the largest single source of
new renewable energy that we have available to
us in the near term, and we need that not only
on the Mayo system but also on the WAF system,
given the forecast.
A  Now, in this business,
Mr. Morrison may want to say something else, in the sense of you have to think of all the possibilities, and there may be a possibility lurking somewhere out there that that answer would have to be modified if somebody provided contributions of something. So you have to be very careful what you say when you are looking for ways to try to make things happen.

But, basically, we have said that in terms of normal economics, normal -- our recommendations, as a company, that this project is contingent on having Carmacks-Stewart in place for the reason I gave, and for an additional reason, you not only have to have it in place, we want it in place by the spring of 2011, so that when we have to shut down the Mayo unit for the final stage of construction of connecting the new unit with the old facility, you have to shut it down. We have access to summer power from the hydro system down south, and they are not running diesels on the Mayo-Dawson system that would add to our costs. So there is a timing issue and a basic requirement issue.

There is this
contingency, if somebody came along and
provided an awful lot of money to help build
this unit today to have it in place but we
didn't have the Carmacks-Stewart line, what
would the company do? The company would have
to think about it.

Is that fair?

A MR. MORRISON: Just to help answer the
question, the question is, Yes, and as
Mr. Osler indicated, but depending on the
circumstances, and depending on, you know,
what's available to us in terms of
contributions and all of those things, we may
have a different answer. But I really just
want to couch it in that -- you know, in that
context, that's all.

Q Based on the information we currently have,
should the Board and ratepayers be looking at
both projects jointly; are they tied at the hip
so that both should be assessed together?

A MR. OSLER: I think the
Carmacks-Stewart project as a general project
has been licenced, and the Board is provided
comments on it, recommendations on it. And it
has a different timing possibility for all
those reasons. And in this world right now, ability to start things quickly may be a factor that goes into whether you could get funding quickly.

So I'm not sure that we should be say that the two projects need to be assessed together if that might frustrate the ability to get funding for both of them.

From the point of view of dealing with the Mayo project, the ideal world would be to deal with the Mayo project in terms of reviewing it, knowing that the Carmacks-Stewart project has been properly funded and is going forward.

A MR. MORRISON: Madam Chair, if I could, I just want to be very precise about the word "assessed." In our -- at least in this jurisdiction, and in our experience -- or let me say it a little differently. Assessment of a project, when we look at it, speaks to us about the YESAB process. That's an assessment, it's an environmental/socioeconomic assessment. And to be precise, the Carmacks-Stewart has fully been assessed by YESAB, the entire project, not just Stage 1, Stage 1 and Stage 2.
So we are finished with that process for that purpose.

Now, for other purposes there are regulatory issues that we still have to face on Stage 2. The Mayo B project is in an assessment process at the moment. It is being assessed by YESAB.

Q Thank you.

Now, you acknowledge on page 4 of 12 that government infrastructure funding is needed in order to make the project viable. What level of government infrastructure funding are you talking about? It says "material portion of the project...." I wasn't sure what that meant.

A MR. OSLER: Well, the statement says in order to get the purchase costs, the generation costs in a levelized sense down to the range of 8 to 10 cents a kilowatt hour, those are the green power generation in British Columbia for new green power.

Other than -- otherwise, the couple of paragraphs up, it says the cost level has to be 18.2. So we are talking when you say material amount of the cost, it's in
the realm of 50 percent of the cost of the project.

But it's essentially to enhance the benefits to ratepayers; the project is still less costly than diesel.

Q Now, when you are saying that you want to get the risks to ratepayers within acceptable bounds, I think that's the terms you are using there, is that expectation that if you got 50 percent of the costs funded, that would put the risk within acceptable bounds?

A MR. MORRISON: Madam Chair, what we're being very clear about here is that we'd like to get the cost into that 8- to 10-cent range, because we think that's what is an acceptable cost range for the hydro project that ratepayers could accept. So if that's an acceptable bound, I think that would be what we are talking about.

There is no argument, from our perspective, that $120 million for the size of the project that we can't go forward with it if we can't get a major contribution, because ratepayers can't afford that. So we are looking at this major contribution. We
will see, hopefully, in the near future, whether we will get that money or not. But without that substantive contribution, we can't go forward.

The real difficulty that we have here is that we have increasing loads. The only option that we have in front of us is to get the quantity of energy that we need. And when I mean that, in the 30- or 40-gigawatt-hour-a-year range is Mayo B.

If we could find another project that was cheaper and we could do it in the time frame, we would be looking at it. This option, with some government funding, gives us a real possibility. You know, at $120 million, we are not trying to pretend it's economic. At 60 or 50, maybe it is getting down into that range, and we think it is getting down into that range. But the balance here is -- and I'm sure we'll come back to this, you know, analysis of the costs and the benefits. The balance is that if we have to -- let me simply put it to you that if we have to generate that 30 or 40 gigawatt hours of new load, additional
growing load, with diesel, that's the easy way
to do it, we just turn the diesels on. Really
simple. We could turn the diesels in Dawson
back on, and, you know, there is 3 or 4 or
5 megawatts there. We can use those. We've
got diesels in Mayo and can use those.

But I would put to you,
and other people who are probably more expert
than I in terms of quantifying numbers again, I
would put it to you that the fuel cost of
diesel, just the fuel cost of generating a
kilowatt hour of diesel, is roughly 25 to
30 cents, even today. So just do the math.
It's really simple: 30 cents times
30 gigawatt hours, that's $10 million a year in
diesel costs. Ratepayers can't afford that.
We don't want to do it for greenhouse gas
emissions purposes, for compliance with all
kinds of regulations.

And when we look at this
project, we think that we can -- we have got
some -- a lot of work to do. We're nowhere
near making a decision to go ahead with it,
because we're looking at certain things falling
into place. And if those things fall into
place and at those levels, we think it does
some -- stand some chance of providing great
benefits for ratepayers.

Q Well, who would have the risks if the capital
costs are higher than your $120 million current
forecast? I'm curious as to how much rigor has
gone into the 120 million number, given the
positions you have taken on your views on cost
maturing as you move forward regarding other
projects. So it seems to me they only go in
one direction.

But if the 120 million
increases materially, 25, 30 percent, who takes
the risk of that?

A MR. OSLER: It would all depend on
the final parameters put together for the
project. But the operating assumption, to be
prudent, is that if you're going to get a large
amount of government funding, you end up taking
the risk for the balance. And if the project
therefore ran into cost-escalation issues, we
have got to take that into account from the
point of view of assessing the risks.

And, frankly, when
looking at this project, it's quite different
than Carmacks-Stewart in, let's just say, a
couple of ways, to keep it simple. One way is
that there is a lot more preliminary
engineering and concept engineering put in here
that was put into Carmacks-Stewart, because you
have to, with a generating station, confirm
siting options and hydrology and terrain and
subsurface conditions and everything else. And
based on that, people have said we won't lose a
tunnel connection. We will use a
canal/penstock option, and be pretty confident
about some other matters in terms of hydrology
and the ability to locate it.

So it's not quite the
same thing at all, and the cost estimates have
been prepared keeping in mind the type of risk
profile I'm just telling you about.

The second thing is that
when Mr. Morrison says that his board is not
prepared to go forward without a material
contribution, he's talking about the very thing
you are talking ability now. He's talking
about all the things that go into the board
looking at risks.

The bottom line, if you
did a simple graph of the numbers that are here, and they are pretty good numbers, you would say, Ratepayers are going to be better off from Day 1 if this project came in at 120 million and they didn't get a nickel from anybody than paying for diesel at today's diesel prices. If the diesel prices go back to where they were, it's simple. But it's an awful lot of money, it's a very big project, and it's got risk.

So the strategic approach has been, we definitely want to get the thing down, with the support of the governments, to the 8- to 10-cent range before the board of directors really would like to be settled with doing a commitment on it, which is really just enhancing the benefit to ratepayers and giving us more and more room to manage risk of the type we are talking about.

Q Just so we are clear, because the answer has been going on for a little bit, but I just want to make sure we are not disagreeing that there are cost risk -- or risks associated with this project where the costs could increase, as you acknowledge on page 5-12; we are not changing
that evidence, are we?

A MR. MORRISON: Madam Chair, we are not here today to talk about going forward with the Mayo B project, and we certainly understand very clearly at this point there's a whole lot of risks that we haven't dealt with or addressed and will get dealt with and will get address as we come forward. We don't have a definitive plan to go forward with this project. When we bring a comprehensive proposal forward, we will address all of those matters of risk, and right now there's lots of risk issues that have to be addressed.

Q You are spending 8.2 million on studies, right?

A MR. MORRISON: We may spent $8.2 million on studies, and we may not spend $8.2 million on studies, to be clear.

A MR. OSLER: Yeah.

A MR. MORRISON: So, again, I hope I'm not being tiresome in trying to reiterate that we look at the project and look at a certain set of information. We had to do some baseline, we had to do a series of tasks we had to complete in order to file an environmental application. We have done that with YESAB. We filed the
application.

We are not going very much further down this road in terms of expenditure, and I mean very much at all, without getting some clear indication as to whether or not we are going to get funding and, therefore, this project is going to go ahead.

So part of the assumption in the spending of the 8.2 or $8.8 million is that we will solve some of those questions, and so we would continue to spend some money. But there's a whole bunch of other decisions yet to be made prior to us spending the money for sure this year, just to be clear.

Q The other thing I just wanted to clarify, Mr. Osler, in following up on a point you made, is that even with a significant government contribution, you are not saying that the ratepayers would not be at risk for cost overruns, right?

A MR. OSLER: I am not saying that the ratepayers would not be at risk of double negative for cost overruns, but I am not -- I'm saying that the company is doing a whole bunch of things to create the environment where there
would be -- where the decision-making would be prudent in light of all the risks.

The project to be viable has an element in it of ratepayer costs, and we tried to define it. There is no way that any utility is going to go forward saying, No, well, we'll pick up all the overruns even if they are prudently incurred in order to provide the benefits to ratepayers saving all this money on diesel.

So if the company is going forward, it will be doing it on behalf of its ratepayers to try and come up with the best way possible for the ratepayers to save money. And that takes some risks that the utility board will have to comment on and will have the ultimate say on as to how much for the to cost go into rates.

Q All right. Can we flip forward to your response to YECL-YEC-1-8 revised, which is to do with the Carmacks-Stewart Phase II.

A MR. OSLER: Yes.

Q And if I look at page 3 of 11 of the response here, again, as I understand it, you are saying the timing of this project is based on YEC, and
I think the word you use is securing the mine loads and contributions. So both of those are prerequisites to the project moving forward?

A MR. OSLER: Just to be clear, page 3-11 is reviewing the background and saying that that was the basis upon which we had discussed it before with the Board and the basis upon which the Board would make recommendations, okay? That it was contingent on having the load that would justify this and also the commitments of money from the customer in terms of contribution and from others, if needed, to make sure it had no adverse effect on ratepayers.

Well, and so on pages 3 and 4 of 11, I think you will find that that background is sort of reviewed. The world today as we go on through this answer is different in many respects. Compared to when we were last before the Board, we now know that there is a major mine development occurring on Mayo Dawson called Alexco Resources, which will utilize the surplus that we previously had talked about being available on that system, and that mine will probably be in service.
before Carmacks Copper could ever be in
service.

Q And we talked about --
A MR. OSLER: I'm sorry, Mr. Keough. I
just wanted to finish.

Q Sorry, I thought you were.
A MR. OSLER: So we have made the point
on page 5-11 that the return economics today,
if we would have gone to the heart of it, is we
need to get the contributions that will let
this project have no adverse effect on
ratepayers. It's a value in terms of being
able to move surplus power around.

But we have actually said
there based on lines 22 and 25, based on
current project cost estimates of $40 million
and forecast Alexco loads and sales revenues,
government and/or mine funding of at least
35 million of the project cost is viewed as a
prerequisite to IEC being able to proceed with
this kind of -- with Carmacks-Stewart Phase II.

So we have moved beyond what you saw on the
previous page to that position today.

Q I am actually not sure I see much of a
distinction. You are still saying you need to
secure the loads and secure funding, right?

A MR. OSLER: Well, we're not necessarily timing it on Carmacks Copper being committed in order to go forward. If we have the funding for all the reasons to do with Mayo B that we just discussed, if we have the funding, this project is very viable and very timely and will not have an adverse effect on ratepayers.

So whether Carmaxs Copper is connected or not connected for the purposes of this assessment, it's a different situation today.

Q But someone is going to have to provide $35 million in contributions and make some commitments, right?

A MR. OSLER: Correct.

Q The estimate of $40 million, is that still your current estimate?

A MR. OSLER: Yes, and it's based on the experience of Carmaxs-Stewart Stage 1. It is not tendered. It has not even, you know, gone through the engineering, but the engineers did preliminary work on Stage 2 as well as Stage 1, so . . .
Q Do you remember what the preliminary estimate for Stage 2 was?

A MR. OSLER: In round numbers it was around 27, 28 million if I'm not -- somebody can -- I say that subject to check as exemplar.

And the big change between the preliminary estimate and this one, and this one is been done internally, is being very cautious about the substation experience we went through in saying Carmacks-Stewart Stage 2, unlike Carmacks-Stewart Stage 1, is a project where substation costs are very material element of the package.

And, therefore, if they are wrong, if they are like the type of costs we saw in the end in Carmacks-Stewart Stage 1, the costs would be higher than the preliminary engineering had estimated.

What's it say?

Oh, it says -- yeah, footnote -- Mr. Bowman has helped me out.

Page 4 of this answer, footnote 5, subsequently developed in the spring of 2007 with preliminary engineering, 29 million.

Q And it was originally at the time of the
resource plan and the Phase 3 Application 70.5?

A MR. OSLER: It was in that range, yes, sir.

Q I'm just reading from --

A MR. OSLER: Yeah, Yeah. Sorry, I handed it back. I should have kept it. I'm sorry.

Q Yes. I was reading the full footnote.

So the original estimate of 70.5, we're now at 40 odd, right?

A MR. OSLER: Yes.

Q Now, also on page 4 of 11, lines 15, 16 -- actually, I think we talked about this already, the Stage 1 substation.

A MR. OSLER: Right.

Q Now, page 5 of 11 we are talking about ratepayer benefits. Again, I just want to be clear that the ratepayer benefits are based on the assumption that you would get the 35 million contribution from somewhere?

A MR. OSLER: For this project it would be beneficial to ratepayers. We think the contribution from somewhere, as you put it, of 35 million is a prerequisite. And it says "at least," as somebody just pointed out to me.
Q  So it could be higher. I hear you.
A  MR. OSLER: That type of escalation
    we like.
Q  Could I ask you to refer to your response to
    YECL-YEC-1-19 revised. And in the response to
    Part A, there is some monthly forecast of
    wholesale sales shown; do you see that?
A  MR. BOWMAN: Page 3?
Q  Sorry, 3 of 9 and 4 of 9.
A  MR. BOWMAN: Yes.
Q  And would you agree that the loads in the same
    month year over year can fluctuate because of
    weather?
A  MR. BOWMAN: Yes.
Q  And am I also correct that in preparing your
    forecast for YEC, you do not weather normalize
    those forecasts?
A  MR. BOWMAN: Well, to be clear,
    Mr. Keough, we're looking at an annual number
    for sales, which is for wholesales. The 2008
    number is effectively YEC's annual business
    plan number, which was developed working with
    YECL.
    The only thing
    Yukon Energy did differently was some
difference in the monthly distributions and
updating the -- and for actuals and leading up
to the time we filed.

The 2009 forecast was
effectively the numbers that came from YECL
inflated to reflect a certain growth that
Yukon Energy thought necessary to reflect on
the forecast above what YECL had. All of those
are done at a wholesale level. We don't have a
mechanism for further weather normalizing
forecast coming from YECL at a wholesale level.

Q So the simple answer to my question was yes,
you do not weather normalize your forecasts,
right?

A MR. BOWMAN: Well, I'm saying we
didn't with the wholesale forecast. We are
working with numbers that largely coming from
YECL. To the extent they are weather
normalized before they're given to YEC, they're
weather normalized, otherwise they are not,
because YEC does not do any further weather
normalization.

MR. KEOUGH: Madam Chair, I am coming
to the end. I just want to take a look at my
questions and consult for one second to see if
there are some areas I need to revisit.

THE CHAIR: Sure.

Q MR. KEOUGH: I just have a couple of questions on your April 24, 2009, update filing, Exhibit B-10. And the first one is on page B-1, Appendix B.

A MR. BOWMAN: We're good, Mr. Keough.

Q I am looking at Table 1, and specifically I am looking at the nonfuel O&M line in Table 1. Now, am I correct that your actuals came in 1.35 million, or 11 percent, higher than your forecast, even though your forecast GRA number was filed on October 6 of 2008?

A MR. MOLLARD: That's correct.

Q Now, I would like you to refer to Attachment B to page 14 of 14 of the same update.

A MR. BOWMAN: I can't read it, Mr. Keough.

Q I can. Must be getting late. My question is, If I look at the right-most set of columns, the "Diesel - E.S.O.," I see that there was significant diesel in the months of October, November, and December of 2008, the actual numbers. And just
trying to understand the basis or the reasons
for that diesel being generated in those
months.

A  MR. BOWMAN: I -- this is dealt with
back in the page B-1 that we were on
originally. And I'm afraid the answer is as
simple as, it was very cold. The fact of the
matter is that December temperatures were well
below normal, so the requirement for peaking
diesel was well above what was forecasted and
what had been experienced in previous months of
that year.

Q  And what about if you go up the chart to
Whitehorse, you see in May, the 175,228 number;
what would be the reason for that?

A  MR. OSLER: You are referring to '08?

Q  Yes. May of 2008 there appears to have been a
spike in diesel.

A  MR. MOLLARD: We will have to get back
to you on that. I don't have that answer with
me.

Q  Maybe we can combine this with the second one,
because you may not have this as well. I was
skipping across to Dawson and seeing in April
there was the 119,000-odd --
A MR. MOLLARD: We will get you an answer on that one as well.

Q Okay. Thank you.

While you are at it, can you confirm that the October, November, December numbers were due to cold weather and not due to some type of outages of some sort.

A MR. OSLER: Yes.

MR. KEOUGH: Thank you, Madam Chair.

I think that does it.

THE CHAIR: Thank you, Mr. Keough.

Good estimation of your time. I thought you might lose it there.

I note it's almost time for our break, so why don't we take one now, and after, I presume, the City of Whitehorse, you will presume cross-examination. So we will have a 15-minute break at this time.

(BRIEF ADJOURNMENT)

THE CHAIR: Please be seated.

I do note we are taking a little bit more than 15 minutes, and I apologize for that, but some people may appreciate it.

Mr. Marriott, are you
prepared to proceed with your
cross-examination?

MR. MARRIOTT: Yes, I am, Madam Chair.
Thank you.

YEC PANEL CROSS-EXAMINED BY MR. MARRIOTT:

Q Now, you will no doubt be happy to hear my
prediction that I won't detain you nearly so
long as my learned friend Mr. Keough did. The
City of Whitehorse considers that we already
has quite an extensive record of many of the
issues of interest to us and sufficient for our
purposes in argument already.

But of course there are
some things that I want to clarify in the
evidence, and I think I'll start with your
opening statement, which was filed today as
Exhibit B-12, and a couple points arose from
that document. If I could take you first to
page 7 of 14. And in the --

THE CHAIR: Sorry, Mr. Marriott.
Which line are you looking at? You are at
page 7 of 14 in the opening statement?

MR. MARRIOTT: In the opening statement,
yes, and in the second paragraph.

THE CHAIR: Second paragraph, thank
Q MR. MARRIOTT: And there Yukon Energy indicates that it now understands through Board Order 2009-1 and subsequent correspondence that it's the Board's desire that a joint cost-of-service study be undertaken now.

And I just want to understand that a little bit. Order 2009-1 was issued January 20 of 2009, so we know that, but I'm wondering what the subsequent correspondence is that's referred to?

A MR. OSLER: I believe there was a letter from the Board to YEC or to its lawyer. I'm not aware of any beyond that.

Q A letter to YEC or its lawyer from the Board; is that what you mean, or . . . ?

A MR. OSLER: Yes.

Q You are not sure right now what that was referring to, what letter or what date?

If that's your answer, that's fine. Maybe you could just let me know when you've remembered what that was referring to. Would that be okay?

A MR. OSLER: That would be fine.

Q Now, it also talks about in that paragraph that...
Yukon Energy now understands what I have
already quoted from, and I was wondering when
Yukon Energy reached that understanding.

A MR. MORRISON: Madam Chair, I'm not sure
we're -- you know, we're not trying to play
with words there at all. It's just based on
the Board order, it's fairly clear that we need
to go ahead and do a cost-of-service study, and
that's what we're going to do.

I don't think we're --
we're not trying to play with words at all.
It's just very clear from the Board order that
that's what we need to do.

Q I'm not trying to play with words either, sir.

A MR. MORRISON: Yeah, no.

Q I'm just trying to understand what you said,
and it says you reached an understanding. I
just wondered when that was. And I guess maybe
I'll follow up with the next question that I
had in mind, and that was, When was the first
time that you advised intervenors that you had
reached that understanding, that in fact a
cost-of-service study should be undertaken now?

Because I would have to
say that this opening statement was the first
that I understood that that was your position.
Now, did I miss something that was communicated earlier?

A MR. MORRISON: No, no, Madam Chair. And that's -- I didn't mean to be trying to not answer the question, if that's what I was doing. Basically we are saying here that subsequent to the Board order, it's fairly clear we're going to go ahead and have a cost-of-service study.

And I would say that this was our kind of our first opportunity to say it in this forum, so this is when we said it. We didn't miss anything. This is the first time we've said it.

Q And as far as YECL or Yukon Electrical, I guess they would have got the letter of May 1, which is now Exhibit B-13, so they perhaps got a couple extra days' notice compared to the other intervenors, is that fair, or would they have known earlier?

A MR. MORRISON: No, that's fair.

Q Now, just moving to page 13 of 14. Just at the top of that page, it's indicated there that the updates do not change the 2008 or 2009 forecast
with respect to fuel.

And I guess I was wondering why there wouldn't have been a more updated or current forecast that could have been used to update those forecasts going into this hearing?

A MR. OSLER: I'm sorry, I'm not -- sorry?

I'm not sure. Is the question why was not an update done to something that -- you're not confused about the fact that we didn't change any of these items?

Q No. I think I understand that you said that the updates were done, but they didn't update the forecast for fuel?

A MR. OSLER: Okay.

Q And I guess really the question is why not?

A MR. OSLER: All right. In terms of fuel price or fuel volume, there would be no rationale to change the forecast for fuel volume unless you were changing either the sales or some capability with respect to your non-fuel generation, and there wasn't any changes in those things.

With respect to the fuel
price, I mean, the approach that we have taken and others have taken is that we took the best price forecast available at the time we made the filing, and we go forward with that price given that the Rider F process is there to deal with the variances that will immerse inevitable between the GRA forecast and the final price. So that's the position that's been taken in hearings of this nature to do with fuel price.

Q I would ask that you turn up, please, your response to CW-YEC-1-16(e) as in England.

THE CHAIR: Sorry, B?

MR. MARRIOTT: E as in England or elephant.

THE CHAIR: Thank you. E as in England or elephant.

Q MR. MARRIOTT: So the question there had to do with what if you were to update based on then current, at the time of the question, diesel fuel prices, and the date used was January 22 of 2009.

It also talks there about updating the GRA for newer oil price changes requires revision to three components: fuel costs, secondary sales revenues, and fixed
industrial Rider F amounts.

So the question I had is just really to confirm that you have also left unchanged with respect to fuel costs those other components listed there, the secondary sales revenues and the fixed industrial Rider F amounts?

A MR. OSLER: This was the response that I referred to in the opening statement as to the three things that oil-related price forecasts affect. And I said that we had in the update changed the Minto fixed Rider F to reflect the final GRA price forecast in the YECL approved GRA Order 99 -- 2009-2.

The effect of that change is that the fixed Rider F was reduced point, I believe, 585 cents per kilowatt hour to .0 -- sorry, .109 cents per kilowatt hour. So if you were looking at page 3 of 4 in this answer, you will see that the mixed -- the Minto fuel -- Minto fixed Rider F, taking the secondary sales price that is assumed here, 77 cents for furnace fuel oil, essentially would wipe out the 170,000 of extra revenue that the .585 cents in the application assume to be coming
from the Minto fixed Rider F.

The numbers we are now using don't totally wipe it out. They remove $138,000 of the 170 from the updated 2009 GRA forecast. The Minto fixed Rider F number is the most complicated of the three sets in the page, and it is also affected by what is the fuel price forecast for YEC's fuel and what is the secondary sales price forecast.

We have not changed the secondary sales rate forecast from the number that we used in the original filing, which was 8.2 cents for wholesale, 9.3 cents for retail, which was the actual price in place at the last quarter of 2008.

And we have not changed the fuel price forecast for generation actually YEC does forecast, which was 117 cents a litre, on average, based on the information we had around August of 2008.

Q Thank you.

Now, if I could just ask you a few questions about your forecast for YEC's primary sales to Yukon Electrical. And I will ask you, firstly, to turn up in the
application a page 2-5. And I am looking there at Table 2.1.

And would you agree that Table 2.1 shows the difference between Yukon Energy and Yukon Electrical with respect to their respective forecasts of what this table refers to as "primary sales"?

A MR. BOWMAN: Yes, as it was filed in YECL's GRA, yes.

Q Thank you.

So from Yukon Energy's point of view, those forecasts are the Yukon Energy's primary sales to Yukon Electrical, and from Yukon Electrical's point of view, those forecasts are for Yukon Electrical's primary purchases from Yukon Energy, fair enough?

A MR. BOWMAN: Correct.

Q Now, even though there are those different perspectives, and even though the forecasts of the respective utilities, as shown on that table, are different for 2008 and 2009, you will agree of course that the actual number, once known in any year, will be the same for both utilities?
A MR. BOWMAN: Correct.

Q Thank you.

Now, in the bottom half of the table, the numbers representing the Yukon Electrical forecast of primary purchases from Yukon Energy, can you confirm that the 260,093 megawatt hours forecast for 2008 and the 263,202 forecast for 2009 came from Yukon Electrical's 2008-2009 GRA forecast?

A MR. BOWMAN: Yes, that's correct.

Q I'm not sure if you know this, the detail, but would you agree or can you agree that it came from, in fact, the Schedule 3.1 filed by YECL in that proceeding?

A MR. BOWMAN: I can accept it. I don't have any recollection of their schedule numbering.

Q Thank you.

Now, YEC, Yukon Energy, was of course a party in the last Yukon Electrical GRA. And I take it you would have examined Yukon Electrical's compliance filing that arose from that decision.

A MR. BOWMAN: Yes. Sorry, I will just say in brief. It was recent, and we have been
preparing for this. So to some extent, yes.

Q Sure.

Now, with respect to their forecast, that is Yukon Electrical's forecast, for its purchases, or primary purchases, as we have called it, as shown in its Revised Schedule 3.1, those forecasts, would you agree, were impacted by Board direction given in the decision in Yukon Electrical's rate case?

A MR. BOWMAN: Yes.

Q And would you agree --

MR. MARRIOTT: And, Madam Chair, I could tell you, I have copies, if it would be helpful, of the particular schedule I am talking about, but I think the witnesses are familiar with the schedule and will agree with the numbers I put to them. So I am in your hands if you want that part of the record. I think it will be clear on the text of the transcript, but I am happy to provide the document, if you like.

THE CHAIR: Seeing there is a reference in the document, why don't we mark it.
MR. MARRIOTT: Sure.

THE CHAIR: So I have that that would be marked C1-10.

I would like to correct the number on the exhibit. It's City of Whitehorse, so it would be C2-7. Okay.

MR. MARRIOTT: Exhibit C2-7.

Exhibit Number C2-7:

YECL Revised Schedule 3.1 from Yukon Electrical's compliance filing.

Q MR. MARRIOTT: Now, I simply wanted, panel, for you to confirm, if you look at line 1 on this Revised Schedule 3.1 from Yukon Electrical's compliance filing, that the Yukon Electrical forecast for the primary energy purchases have been revised upward to now, for 2008, 263,765 megawatt hours, and for 2009 the figure is now 267,747 megawatt hours; do you agree?

A MR. BOWMAN: Yes.

Q And I am just wondering if the change in this forecast made by Yukon Electrical in response to Board directions in its decision has been reflected in the Yukon Energy application update.
Q  Is there an explanation why that was not done?
A  MR. BOWMAN:  Yes. The -- we reviewed this information coming out of the Yukon Electrical compliance filing, particularly with respect to 2009, because of the exact matter you note; there is a certain consistency with what is bought and what is sold. They are attempting to track the same thing.

    For 2009 the number that is in the schedule is 267.7, coming out of the recent YECL decision, and that's up considerably from the number that YECL had used. Yukon Energy's forecast in its application filed last October was already at 267.0. So within about .3 percent of that level.

    There is an offset in the change of the secondary sales that's even larger, but where Yukon Energy is forecasting 16 and Yukon Electrical's reflects about 7 gigawatt hours of sales. But looking at the primary energy, if anything, it's served to confirm and underline the reasonableness of
Yukon Energy's 2009 forecast.

With respect to 2008 the situation is somewhat different. Yukon Energy's forecast, which was incorporated in the October filing, was to -- as you said, 259.0, compared to the YECL compliance of 263.8. But as we have covered already, there's a -- the situation that we're in with respect to timing of this GRA is challenging in respect of dealing with the future forward test year type of jurisdiction where you have a year of actual behind you and you have -- you are trying to deal with a set of forecasts and testing the reasonableness.

With respect to the filing, we have 2008 actuals behind us on a lot of matters. We know there were a lot of items that went up and a lot that went down, and that at the end of the day, if anything, the actual results served to underline the extent to which Yukon Energy has underearned its return on equity and that the net effect of the various changes from forecast has gone against Yukon Energy to the extent that we're now talking about an actual ROE in 2008 of...
7.2 percent.

The number here, if anything, was one of the things that was favourable in 2008 that reflects wholesale sale somewhat higher than had been forecast.

But viewed in the sort of sum total of 2008, and the overall testing of the reasonableness of the 2008 forecast, we didn't see it as an item that one would view as a sort of overwhelming reason to cherry-pick, if you like, or to pick off an item and adjust the GRA.

I guess the other sort of just to put a point on that, when we talk about the 2008 updates, this is a concept that's been around for some time that we talked about back at the workshop when we talked about what we filed. But it is -- it has never been a concept that said that we'd take all the forecasts or any subset of the forecasts and update them for the time we come into the hearing.

It was effectively an update solely for four items, intended to be for four items, that Yukon Energy knew at the
time it filed its application were major
outstanding items and would be materially
affected and materially better informed by
getting the -- you know, the intervening
information in place: one being what came out
of YECL's hearing, one being the data
connection of the Carmacks-Stewart, one being
the ROE that was adopted by the BCUC, and the
fourth being the rate case costs, all of which
are effectively items beyond YEC's control.

The only fifth item we
threw in was a correction that we identified
when we went through the interrogatory round,
that there was a mathematical error in the
application; we corrected that. So it was
never meant to be a wholesale update to the
application, and as a result, this wouldn't be
a number that would get changed. It wouldn't
get triggered to be changed by that type of
process.

Q Thank you for that.

Now, I just wanted to
discuss the Yukon Energy's forecasting
methodology for this particular forecast. In
general terms, and let me just put some flesh
on those bones for you, because I don't want you to necessarily go through every single aspect of that. But what I'm interested in is the cooperation, or lack thereof, between the two utilities in coming up with these numbers.

Now, I think you said in the response to YECL-YEC-1-19(f), (h), (j), and (k) that Yukon Energy is not provided with YECL's customer-specific data and cannot carry out detailed assessments of the underlying customer class growth underlying wholesale growth, and then you went on to say that it was not apparent that overall wholesale forecasting, at least for the current application, would necessarily be improved through prior access to such additional information.

So I'm not sure what you are saying by that, but would it be fair to say that you are indicating that your wholesale forecasting is more accurate than Yukon Electrical's despite not having access to Yukon Electrical's customer-specific data, or was there some other message intended there?

A  MR. BOWMAN:  Mr. Marriott, the numbers
tell the story the numbers tell. The fact of the matter is that Yukon Energy has been wrestling with the issue of Yukon Electrical's wholesale forecast for some time.

Just in terms of helping those in the room who weren't present, we had a fair bit of discussion of this in the 2005 proceeding. During that proceeding Yukon Energy used Yukon Electrical's forecast, had adopted it directly into its own forecast. We noted we had some concerns with it, but given we didn't have access to the data, we didn't have a reason to override it, if you like, or to insert another number, and that approach was accepted by the Board.

In the resource plan hearing, a considerable more level of discussion was had about the wholesale forecasting matter between the two utilities. There was an undertaking that was provided that showed the forecast, long-term forecast, prepared by each utility in relation to actuals over time.

But, nonetheless, at that point in time, Yukon Energy had started to --
only started to move towards amending, if you
like, or adjusting the wholesale forecast to
reflect what it had seen as, in a mathematical
sense, of sort of persistent underforecasting.
It showed up in '06 and just changing the
monthly distributions.

By '07 Yukon Energy had
actually started to insert an additional amount
into the forecast because the numbers were just
not holding up. The actuals were coming in
persistently above the level of forecast to the
point that it only made sense that we try to
add an additional factor to those numbers.

Exactly the same
situation occurred in 2009 when you looked at
the -- what Yukon Energy knew of monthly sales
to date and of what was going on in the load
situation at a generic level. The forecasts
that were filed by YECL in its hearing and that
it was relying on did not seem to bear out as a
reasonable forecast as what would occur with
wholesale sales. I think the Board came to the
same conclusion and, if anything, basically
echoed the 2009 adjustment that Yukon Energy
built into its own application.
Your question was about sort of access to data, and I guess the evidence or the point that we're attentive to is that reams of additional data that could be generated and could be analyzed doesn't always lead to a better result, and it may not lead to an efficient result if the two utilities are trying to pore over, you know, lots of customer-specific data each on their own to try to come up with the results.

There is a certain efficiency that -- in having the utility that has responsibility for distribution and for customers and for evolution of customers having that role. Yukon Energy wouldn't look to replicate the work that was done but may look to put in place an avenue to help do a reasonableness top-down correction on that.

Now, as the two utilities working together, and Mr. Morrison may want to add something, I am speaking at sort of a technical level, but the response you looked at, it said it wouldn't necessarily improve the forecasting is because there already has been an analytical level done on the data.
The check that Yukon Energy does was not to replicate that. It was to instead do a top-down reasonableness check, which is a common type of cross-checking one would do on a set of data. That's it.

Q That was a fairly lengthy answer, and I wanted to pick out perhaps a couple of points that I heard, I think. One was that I think you're saying that your experience has been that Yukon Electrical attempts to underforecast this number. Did I get that right?

A MR. BOWMAN: I'm only talking about in respect of a mathematical relationship. Underforecast could -- I mean, could mean all sorts of things. But just looking at the mathematics, the exhibit that we've filed in the 2006 resource plan hearing and the case since then, which was reviewed in their -- the Yukon Electrical GRA, the tendency has been on a sustained basis that actual sales come out higher than was forecast at the beginning of the year. I don't want it to be overread, the comment. It's a mathematical relationship.

Q Right. But I guess what I'm looking for now because you said that, and you could do this
however you like, but in general terms if you can, your forecast, that is Yukon Energy's forecast for 2008 was actually lower than what Yukon Electrical's was. What was the driver for that?

A MR. BOWMAN: Well, as I said, in 2008 in preparing its business plan, Yukon Energy did not in that year elect to increase Yukon Electrical's forecast. It elected to use the same forecast as Yukon Electrical was using because it seemed in that case to not require the same type of adjustment that was done in '07 that was ultimately done for '09. There was some small relocation done in terms of the monthly distributions, which is basically an internal tracking matter.

Q Sorry, I am talking --

A MR. BOWMAN: But in addition, the GRA reflects a half year of actuals in '08 that Yukon Electrical didn't have the benefit of when it filed, so . . .

Q I think that's the part -- I wasn't sure if you were leaping ahead again to where I started, which was after the YECL compliance finally came out, but you were talking about the time
frame when you filed the GRA in your last response?

A MR. BOWMAN: When we filed the GRA, and this was discussed just before the table you were noting was it for 2008, Yukon Energy and Yukon Electrical had the same annual sales forecast at the start of the year.

They may have used a slightly different monthly distribution, but the same annual sales forecast. The differences in 2008 arise for effectively two reasons as noted, that the primary one being we had a half year of actuals.

Q If I could just confirm for the record, this is in your April 24 updates filing, I gather that in that filing, it included some 2008 preliminary actuals, including a 2008 preliminary actual for this primary energy sales number that we have been talking about. And it's found at the PDF pages 47 of 94 in that update. It's Schedule 11, but I think there may be more than one Schedule 11. So if you go to page 47 of 94.

A MR. BOWMAN: For the paper version, it's in Section B of the Filing Attachment B-1,
and it's page 13 of 15, but it's effectively
the same schedule that would be shown in
Table 2.2 of the application.

Q And the 2008 preliminary actual for primary
energy sales has come in at 263,820 megawatt
hours?

A MR. BOWMAN: Correct. That's the
positive variance I was talking about, which is
one of the things working for the numbers in
2008.

Q And I think going back to a general discussion,
I think you told us in the response, when I say
"us," I mean all intervenors and the Board, to
YECL-YEC-1-19(g) that YEC did not discuss its
wholesale sales forecast assumptions with
Yukon Electrical prior to filing its
application.

And I'm just wondering
going forward if -- and I think you may have
made mention of this in the opening
statement -- is that something that
Yukon Energy would hope to change going
forward, in that these forecasts could be done
more cooperatively by sharing information and
perhaps having the Board approve one forecast
instead of two?

A MR. OSLER: Let me have a shot at this one. If the two utilities were filing at the same time, what we said in the opening statement and in the letter to YECL is we'd like to look at ways to in the future achieve filing at the same time, having one hearing for everything. And it would make sense if everybody could agree to try and get the things that the utilities can agree on, such as the wholesale sales, as one package.

There are two utilities in this instance, though, and they would have differences of opinion, as the Board has seen in the two filings that were made. So a little bit of patience may be required for everyone to sort of settle down and get used to, okay, everybody's been back before the Board, the Board has made some decisions on various matters, including forecasting, and maybe it's possible for the staff and the two utilities to now get together and not be concerned about differences of point of view.

It would be certainly desirable, but we have to see if that objective
can be achieved.

Q Thank you.

Now, I would like to move to a different area and talk a little bit about some dead issues, if I could. And I will take you to Exhibit B-9, which is your letter of April 1, 2009, responding, I think, to application for further responses. And if I could take you there to page 19.

A MR. BOWMAN: Mr. Marriott, I have the April 1st letter listed as B-11. Give me a moment.

A MR. OSLER: Page 19 of the letter, Mr. Marriott?

Q Yes, I thought it was B-9?

A MR. BOWMAN: You are right. I just have -- I apologize. My mistake.

A MR. OSLER: So we're --

Q So at 19, and I just wanted to refer to the statement that's made there that Yukon Energy's (quoted):

"...only external debt is the TD Note {that's Toronto Dominion Note, I take it} which is guaranteed by the Yukon Government through YDC."
And I am wondering if the terms of that note demonstrating that that debt is guaranteed is found somewhere on the record of this proceeding.

A MR. BOWMAN: On the matter of the TD note, yes. You will find it at Tab 9, which is the audited financial statements for the year ending 2007, and it's at Note 13 of the notes to the financial statements, which is -- it's at the bottom of the page. I'm not sure if you want to turn there.

In the financial statements it's page 17, but in the GRA page numbering it's page 9-19, and it notes in respect of the (quoted):

"TD Canada Trust

"{It's a} $12,400,000 term note bearing interest at 7.81% payable in monthly installments of $102,000 interest and principle, with the balance due September 30, 2011. The note is guaranteed by the Yukon government."

So that would be where the details are on that note are.
Q Give me a moment to turn it up. Did you read the entire footnote that you were referring to?
A MR. BOWMAN: I was reading the note in respect of the TD Canada Trust note in the -- in Note 13, which is in long-term debt. There is a discussion of each of the long-term debt instruments; it is just the TD that I read the entire note.
Q Okay. I see it.
A MR. OSLER: This was filed in Tab 9 of the application.
A MR. BOWMAN: This is Tab 9 of the application.
Q The reason I was asking if you read the whole thing, I wasn't sure if in there it actually details the onerous repayment terms of this note that you referred to in a couple of IR responses.
Your responses to YUB-YEC-1-14 and LE-YEC-1-38 talk about onerous repayment terms of that note. And I am just wondering what are those onerous repayment terms?
A MR. MOLLARD: The note itself isn't
specific on -- doesn't allow for repayment, so we are bound by the terms of the interest act, which requires that we pay the greater of three months' interest or the interest differential. And given today's current low rates, that would be a fairly penal -- there would be no point, basically, in negotiating, because we would have to pay the full differential.

Q Is that a calculation that you could provide for us, perhaps using what you think you could reasonably replace the amount of the instrument for in terms of an interest rate, and then just do the calculation to demonstrate what you are telling us?

A MR. MOLLARD: If it works, I could probably use the rate from the most recent debt that we issued December 31st, '08, the 4.65 percent.

Q Why don't we do that. Would that be an acceptable undertaking?

A MR. MORRISON: Let me be clear. Let me just add a little something here. We can do the calculation. We would do it based on what we
can get debt today for, not what we got that
last debt for, because clearly, from our bank
manager, we have been told that this last debt
that we got was very cheap. I'm not sure where
we are at today, so I don't want to get stuck
on the 4.65, and so I just want to look at
it.

Q That's fair enough.
A MR. MORRISON: That's fair enough?

Q Just give us in your answer the explanation as
to why you are using whatever rate that you are
using, but it would be on the assumption that
it would be a rate that was achievable.
A MR. MORRISON: That's fine.

Q Fair enough?

Now, if I could get you
to turn up your response to CW-YEC-1-27.
Really, I'm looking at the Attachment 1 to
that. The question was (quoted):

"Please provide the terms and
conditions of the Yukon Development
Flexible Promissory Note (for
Mayo-Dawson Project) and the 7%
Flexible Term Note that sets these
debt interest rates"

is the question, and you had provided us with
the two attachments. Attachment 1 is the one I
would like to look at first.

If I could take you in
that document to Clause 9. I believe that's at
page 3 of 5.

A MR. OSLER: Yes.

Q Now, there it refers to (quoted):

"...a first fixed and specific
mortgage and charge containing all the
terms of the encumbrance set forth in
the schedule to the Security
Agreement...."

Now, is the security
agreement that's referenced there part of the
record in this proceeding?

A MR. OSLER: No.

Q Is that something that could be produced?

A MR. OSLER: It wouldn't -- I don't
know. I'd have to go and find it because
it's -- no longer exists. The problem here is
that this document was originally settled
between Yukon, Yukon Development Corporation,
or as they say here, Yukon Power Corporation
and Canada. So that was security agreements
that were all part of that package. I'm not
sure what the arrangements are now that Yukon
Development Corporation has purchased this from
Canada. But there is no security agreement
between the companies and Canada anymore, that
I'm aware of.

So the language here
reflects that earlier time period. I'm not
aware of any fixed or specific mortgage, either
from Yukon Development of this facility. That
was a Canada requirement in order to provide
this money at the time. So it's a lot of
history.

Q So, basically, you are saying that that clause
does not reflect the security obligations, if
any, surrounding the borrowings that we were
asking about? Did I get that right, or have I
missed something?

A MR. OSLER: Well, that -- this note
is now held by Yukon Development Corporation,
not by Canada. It was purchased by Yukon
Development Corporation from Canada without any
change to the terms and conditions.

Q Sorry. Without any changes?
A   MR. OSLER: Without any change. The note was purchased as is. So I have no knowledge beyond that, and others will have to take into consideration what, if anything, exists. There was no new security agreement made between the parties that I'm aware of. There is no security agreement that I'm aware of that's outstanding, and I'm not aware of any mortgage.

Q   Well, let me understand this.

   So if this note was purchased by YEC and they didn't make any new arrangement or new agreement, would they not have it under the same terms and conditions that are reflected here, including any referenced security agreement and what it says in there, or is that something that you just -- you don't know?

A   MR. OSLER: I have to say I don't know. It sounds like a legal question.

Q   Well, it is a factual question, really.

A   MR. OSLER: Yeah.

Q   But perhaps just one of you could investigate and let us know.

A   MR. OSLER: We could investigate and
let you know. But for everyone in the room,
this was a key term -- I didn't realize when I
was going to do a history I'd get this far
back, but this was a key term of the transfer
agreement that took NCPCs and transferred them
to Yukon and everything else. It was a note
that covered the Whitehorse 4 unit because
Yukon Government had intervened in a hearing of
the National Energy Board, which some people in
this room took part in, in many different ways.

And the National Energy
Board determined that the borrowings with
respect to the Whitehorse 4 unit should not be
used as part of the revenue requirement of NCPC
at that time because the asset had no useful
economic value at that time.

The flexible term note
effectively kept Canada bearing the risk with
respect to the usefulness of the asset. When
Yukon Development Corporation purchased this
asset, they purchased it under the
understanding with Canada that the asset didn't
look all that valuable, and they got it at a
lower price than the book value.

And Yukon Development and
everybody else has been doing a lot to enhance
the value of this note since then, et cetera.
There is a whole history behind it, but it's
held now by the very party that owns
Yukon Energy Corporation, so it's a totally
different situation than when it was originally
negotiated at arm's length with Canada.

A MR. MORRISON: Madam Chair,
Mr. Marriott, we will have a look, see what we
can find for you, and try and provide a
response.

Q Thank you.

Now, in the response to
CW-YEC-1-27(b), as in Bob, it states that
(quoted):

"YDC has earnings from interest,
investments and dividends {and then in
brackets} (typically interest and
dividends from YEC)."

My question is, Can you
tell me if YDC ever incurs debt or otherwise
borrows money on behalf of YEC?

A MR. MORRISON: Madam Chair, sorry, just
to make a minute, we're just trying to recall
and answer the question accurately. So is
the -- so the question -- let me try and answer it this way: I'm not aware of instances where YDC borrows money and then relends that money to YEC. I can't think of any instances of that. That's what we're trying to -- kind of our collective memory, because Mr. Osler's memory goes back a long, long way.

So I just can't remember any -- and we generally don't -- I don't -- I can't think of anything where we have done that, if that's the question.

Q So let me put it this way: You can't remember any instances of that, and there are no plans going forward that you're aware of for that to occur?

A MR. MORRISON: For YEC to borrow money and relend that money to --

Q Back to YEC?

A MR. MORRISON: There is none that I'm aware of at the moment.

A MR. BOWMAN: Certainly just to keep it very sort of specific, none of the debt, financing, ratebase, or anything of that sort there would be in this application, there's any on behalf of or any of that nature of the
question that you asked, you know, without
getting really into ancient history or
something. I don't recall any in ancient
history either, but very specifically there is
none in '08 or '09.

Q Let me take you to Schedule 13 in the
regulatory schedules and just ask a specific
question.

THE CHAIR: Sorry, Mr. Marriott,
what's the reference on that again?

MR. MARRIOTT: I'm just getting the
reference, sorry.

A MR. MOLLARD: It's page 7-17, I
believe.

THE CHAIR: I'm sorry?

A MR. MOLLARD: 7-17 of Tab 7.

MR. MARRIOTT: Under Tab 7 in the
application, 7-17. That's Schedule 13.

Q MR. MARRIOTT: Now, at line 10 it lists
there a YDC Loan Number 18?

A MR. BOWMAN: Yes.

Q Of $5.825 million.

MR. BOWMAN: Now, how does YDC finance
that loan?

A MR. BOWMAN: If you don't mind, I just
want to deal with the number in the question, and then I can deal with the specifics of it.

Q  Sure.

A  MR. BOWMAN: You had pulled out Schedule 13 from the application, Loan 18, and referenced at 5.825. 5.825 is a number that arises in 2009 in the filing had YEC not had a general rate application in '09.

The next column over, which is called "Proposed," references what was in the application with a general rate application. So instead of 5.825, the number would have been actually 5.043.

And if that's not enough numbers to keep everyone confused, that number would change slightly in the update as well, which would be in Exhibit B-10, because it's sort of a number that changes almost every time you do something, and it's actually 4.963.

So in the final Tab 7 that is included in Exhibit B-10, Attachment A-1, the number we would be talking about that's expected to be -- we know it is 4.963. So I just wanted to deal with the number side of it.
Now, your question was
how does YDC finance that number or that amount; is that what you're . . . ?

Q Yes. That's really -- I was just using it as an example, but thank you for the clarification. I certainly don't want to mislead anyone. But really the question had to do with, you know, where do they get the money for, you know, borrowings like this or lendings like this I guess would be more appropriate from their point of view?

A MR. MORRISON: Madam Chair, YDC has its own sources of funds, as I think was indicated in a reference made to an earlier IR. It gets dividends and interest from other loans from YEC. It had funds available to it over a period of years that it generated. That's where those monies come from.

Q And that's what I was trying to get at. You've indicated -- and, you know, to be honest, before I came in here, I wasn't sure if there maybe was some access to money markets to get some of that money. You're telling us no. But you has said in your earlier responses that it's earnings and
dividends and investments, and what we were trying to ascertain, Is that the only source of those funds? Because I don't think you said expressly that it was in your responses.

You said -- we asked you how they got the money. You said they have these sources of income, but you didn't say those were the only sources. And I just want to know, is there some other source that we're not hearing about?

A MR. MORRISON: Again, none that I can think of, but, you know, was there sources of funds that YDC had received, you know, back in history that I'm not aware of? There may have been. But I can't think of any in my memory. That's not the normal.

Q All right. Thank you.

Mr. Osler, did you have something more to say?

A MR. OSLER: Let me just -- whether you needed to have any more explanation of what goes on at the end of each year and the 60/40 process, this number that everybody is pointing to, all these loans are done at the end of each year to ensure that the debt equity ratio stays
60/40, so its dividends are set to the amount necessary, et cetera, et cetera, to keep the capital structure whole. That's why it stays the same, and it's been that way for a long time.

So if you haven't been around and dealing with it, you might not even get that point, which is what my colleague had said. And the other thing is that traditionally we haven't gotten into it in front of the Board, the business of YDC, so some of the reticence you see in the answers just reflects that tradition. I mean YDC is a totally separate entity, and how it deals with its business is another matter.

But the fundamental thing you are getting at, YDC doesn't go out and borrow money in order to set this stuff up. The cash flow works the way everybody has been describing it.

Q All right. Now, I would like to explore a different topic, and it comes out of response to CW-YEC-1-13(a) and (b). If I could get you to turn that up, please.

So there the response
indicates in part the issue of efficient price signals and the issue of conservation activities are separate and distinct matters. And we have raised this with respect to this idea of the increase in the second block rates for residential, and we were trying to get at the rationale and so forth. And we asked had you considered other conservation methods or activities, and we received this response.

So the issue of efficient price signals and the issue of conservation activities are separate and distinct matters was your statement.

Is it Yukon Energy's position that its initiative to rebalance the first and second blocks of the residential rate was intended primarily to send out efficient price signals and not as a conservation measure?

A MR. OSLER: Essentially the -- given those two choices, it would be price signal for all the reasons that Mr. Morrison was talking about in his opening statement.

But essentially this matter was reviewed by the Board itself in...
1992, which we attached to one of the answers, their report, and they did address the reasons why they thought one should have these type of price signals. And I'm not sure whether they use the words price signals or economy and efficiency.

The order in council uses the word economy and efficiency. It doesn't use conservation. So I'm not sure anybody put their mind to it at great length, but efficiency has been the buzz word that everybody has been focused on as far as I can recall with this particular matter for a long time.

Q Well, we're trying to understand if you're drawing a distinction, and, you know, maybe you can help us if you are drawing a distinction to explain what it is.

You know, when I think about price signal, I am thinking that the price is sending a signal out to do something or not do something, and I'm not sure in this context what it would be other than to use less energy, if that was something within the customer's control.
So that's where I'm struggling. There seems to be a distinction drawn here, but I'm missing it, and maybe you can help me with that.

A MR. OSLER: When it was discussed in '92 at a fundamental level, people talked about objectives of ratemaking, including efficiency and fairness and other things, and the efficiency objective being relating to giving people the right price signals so that they can make efficient, in terms of economic, decisions if they have choices.

And if they don't have choices, they at least have a clear idea of what the value of the good or service they are consuming is, and they can make conservation decisions on that basis.

So I'm not sure anybody was saying at that time or subsequently that the objective for sure is to get people to use less electricity per se. It was just a good thing from a ratemaking policy point of view and from principles point of view to have efficient price signals aside from the fact that it had been mandated way back for all the
diesel zones that block or runout rates should be reflecting the incremental costs of diesel in the areas that were being served by diesel generation. It wasn't until after the Board's recommendations in '92 that that concept got carried over to the hydro zones, in part on recommendation to this Board in its report in '92.

Q Now, with the proposal that YEC is still carrying forward on the increase to second block residential rates to the extent that that is a signal that is being sent, what if any response does Yukon Energy expect from customers if their proposal is approved during the test period?

A MR. OSLER: Essentially the answers we have provided I have said we have not made any estimate or assessment of a change in consumption in the test years. We would expect that if there was such a change it would be probably longer run. But we certainly don't have the ability to at the moment predict it. And secondly that the concept of doing what we're talking about is not a novel new concept, it is just getting back to what we were all
doing in the 1990s the last time we had a complete review of this.

So it's -- it was the norm to have this type of a price signal for the second block rate when we last had a GRA in '96, '97.

Q When you say "this type of a price signal," just so I am understanding, do you mean one that is moving towards a price based on the incremental cost of diesel, or do you mean something else?

A MR. OSLER: Well, in the application we are setting a price that's moving towards it, and in the Board's report in '92, which was attached to YUB-21(d) the Board said it this way (quoted):

"The Board considers that runout rates should reflect short-run incremental costs in each of the rate zones as specified in the OIC and that fixed costs incurred by the companies should be recovered by demand charges, fixed charges and energy charges in the first energy block. The Board recognized that this will result in
the increase in the hydro zone runout rate."

Which was the topic of the day. The Board's rationale before that, page 40 and goes into it in depth what you are talking about. But they looked at it quite thoroughly in that report, and they meant moving towards incremental costs on diesel generation in the way in which it was implemented before that report was written for the diesel zones and after that report for all zones.

Q Well, let me take this maybe to a higher level. I am trying to understand why you don't think customers would react to this in the short term, so let me put something to you. Would you agree that a rational customer who finds that the cost of electricity above a certain level of consumption was increasing while the cost of consumption below a certain level of consumption was decreasing try and move their level of consumption below that particular level by eliminating discretionary electricity consumption like turning out lights when you are not in the room and turning down
thermostats and the like.

A MR. OSLER: As an economist I fervently believe that a rational customer will take account of price signals and make some decisions accordingly. But in the realm of electricity pricing, we have observed that, you know, there are limits to how much people really have the choice involved, and it's a gradual process. And the utility that -- the Manitoba Hydro Utility where they have very low rates relative to a lot of people, they claim that they get better power smart results than some of the utilities that have very high rates because they go out and pay attention and encourage people to do things. I'm not going to comment on whether that's absolutely the case, but that's their pitch.

People have faced very high oil prices recently, and they may have changed their behaviour. There's -- in terms of where there's choice, the modest changes that we're talking about here don't even come close to getting up to what we thought was the oil price signal range. Given the decline of the oil price, it's still what we were
proposing less than what would be the type of price relationship to oil that existed in '97. And for all I can recall from '97, people weren't suggesting from the two utilities when they came before the Board then that this change would make a predictable amount of reduction in the consumption of electricity on the WAF system, in part because we didn't know how to estimate it or perhaps because it wasn't at an evidentiary basis to do it.

So yes, rationally the price should make a difference if it goes up. How much of a difference, though, is very hard to talk about, and we're still a long way from having a price relationship to oil as a competing product that we in the past had throughout the territory for second block rates.

Q Now, I don't want you to repeat yourself here, but I am going to ask a question with respect again to this idea of efficiency. If you have got nothing more to tell us, you know, that's fine. I just want to make sure I give you every opportunity. But the next question was whether Yukon Energy would consider that any of
those efforts that I talked about like turning off unnecessary lights or turning down thermostats or what have you, if that could be characterized as an effort to not waste energy or electric energy, would you agree that that could also be characterized as efficient use of electric energy?

A MR. OSLER: In one sentence I'd say yes. I mean if you have those results as a result of a price signal, an economist would say we are seeing efficient use being encouraged. What we are talking about a few minutes ago when I was being a bit more long winded was whether we would get a change or not. But if you get a change that's due to that, that's supposed to mean that price is relating to a change in behaviour, and that tells you that it's not just a signal, that it's having some effect.

Q Now, let me take you a further step. I'm not sure, Mr. Bowman, did you have something there? I didn't want to cut you off.

A MR. BOWMAN: No.

Q In the event that the Board were to approve the runout rate proposal and to the extent that
customers did reduce their second block of consumption, would this result in a reduction in the volume of diesel generation?

A MR. OSLER: In the whole territory if it happened in some of the diesel zones, the answer is yes. Today in the test years given the forecast with respect to the Whitehorse, Aishihik, Faro, and the Mayo-Dawson system, the answer would be no.

But what we are telling you is that we think sooner than we like, diesel could be indeed on the margin in those systems, both of them. And if we don't start planning to have rates that reflect the price of diesel and if the diesel price starts to go up again, we are running after it as it keeps climbing, the answer will change the next time we meet perhaps. And the answer will be if they were more efficient in those areas they would be saving diesel directly.

And that was the answer that would have been given in '96, '97. And that was the answer that was in the Board's mind when it dealt in '92 with a situation throughout the territory when diesel was on the
margin in all the rate zones except perhaps Mayo-Dawson because of the closure of the mine there. But otherwise of the Mayo system, diesel was on the margin everywhere else.

MR. MARRIOTT: Madam Chair, I just want to consult with my colleague here for a moment. I may be done.

Q MR. MARRIOTT: I am going to ask you to turn up another information response, CW-YEC-1-13, the (c) and (d) portion of that in lines 27 to 29. And there it states (quoted):

"To the extent that conservation occurs due to consumer response to the second block rate, it is expected that this will occur over time as noted in PWP/HML-YEC-1-6. Any revenue reductions that occurred would form part of future Yukon Energy GRAs."

And then if we go to that referenced information response, the PWP/HML-YEC-1-6, you there give the reason for that belief that consumption won't change as a result of an increase in the second block and the reason given is (quoted):

"Yukon Energy does not anticipate
price elasticity of demand leading to reduced second block use to be a material factor in the test years. This is because electricity as a commodity is typically not particularly elastic, and any consumer price elasticity is normally understood as a longer-term factor."

And in making that statement did Yukon Energy have any particular econometric study in mind that shows that electricity is inelastic?

A MR. OSLER: Mr. Bowman can follow up if -- I'm not aware we had a specific study in mind. It was a comment made in the context of would this particular change, given how far it is behind oil, be likely to make any estimate that anybody could make in the short term of the test years and based on various hearings and various experience, the answer was we didn't think so.

Mr. Bowman can comment whether he had some particular study in mind. But this sort of generally speaking when you listen to people talking about it in various
places is the type of framework that you get used to hearing. We didn't do any specific study or do any particular research to back it up in this hearing.

A MR. BOWMAN: I have nothing to add.

Q So it sounds like this is a reference to an impression or gut feeling earned over years of experience from hearings and references to unspecified studies. I am not trying to be unfair, but that's what your answer sounded like to me.

A MR. OSLER: Well, at my level it would probably be that, because I'm not busy researching the stuff. Mr. Bowman probably can give you a lot better than just gut. Go ahead.

A MR. BOWMAN: Well, it's been the subject of a fair number of the proceedings that I have been involved in at various times over the last few years, particularly in Manitoba. And in those cases people were reviewing specific studies. I didn't have any specific study in mind. But it's -- for people who are involved in the feeling, probably gut is not the right characterization but sort of common wisdom that regardless of the studies
that have been done over time or where you have looked at whether it's down south or in Canada, California, the sort of persistent result is that people have unfortunately a very poor ability to respond to electricity prices in the very short term.

You may see people turning out lights as you say, but those are not dramatic changes in the overall consumption. Where you really start to see those effects is when you get into elasticity type of studies is over the longer term. And you see it certainly more in industrial type of operations than you do in residential. The classic relationship is residential loads over the short term are among your least elastic. Residential loads over the longer term become somewhat more elastic because over the longer term, people have the opportunity to buy a more efficient fridge. They don't do that tomorrow. Tomorrow they might turn out the light. But a couple years from now when they replace the fridge, they might buy a more efficient fridge if the price is right.

In industrial operations...
elasticity goes away, because in certain cases, they'll shut down and stop using power entirely. But residential loads are notoriously inelastic, so it's not gut. It's beyond gut but no specific study in mind.

Q So are you saying, Mr. Bowman, that the studies that you are thinking of would bear out the statement that electricity as a commodity is typically not particularly elastic more so in the short term than the long term?

A MR. BOWMAN: Yes.

MR. MARRIOTT: Thank you, Madam Chair. That brings me to the end of my questions subject to answers to undertakings. And I see it's probably a convenient time to break for the day.

THE CHAIR: Thank you, Mr. Marriott. I note that we are at the time that you mentioned that we would take a break for the day, and we will reconvene tomorrow morning at 9 a.m.

(PROCEEDINGS ADJOURNED AT 5:56 P.M.)
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IN THE MATTER OF the Public Utilities Act
Revised Statutes of Yukon, 2002, c. 186, as amended

and

General Rate Application for 2008-09 by Yukon Energy Corporation

PROCEEDINGS

May 6, 2009
Held at High Country Inn
Whitehorse, Yukon

Volume 2

TAKEN BEFORE:

Wendy Shanks Chair
Robert Laking Vice-Chair
Jody Woodland Member
Kathleen Avery Member
Richard Hancock Member
APPEARANCES

Wendy Shanks  Chair
Robert Laking  Vice-Chair
Jody Woodland  Member
Kathleen Avery  Member
Richard Hancock  Member

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Bob Clarke  Technical Consultant
Deana Lemke  Executive Secretary
Kori St. Jean, CSR(A)  Realtime Reporter
Georgina L. Lawrence, CSR(A)  Production Reporter
Julie Snijder, CSR(A)  Production Reporter

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L. G. Keough, Esq.  For Yukon Electrical Company Limited
T. D. Marriott, Esq.  For the City of Whitehorse
M. Buonaguro, Mr.  For Utilities Consumers’ Group
J. F. Maissan, P.Eng.  For Leading Edge Projects Inc.

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(PROCEEDINGS RESUMED AT 9:05 A.M.)

THE CHAIR: Please be seated.

Good morning, everyone.

Just with respect to a couple preliminary matters. We would like to have our lunch break from 12 to 1:30 again, and take a short break around 10:30 this morning and an afternoon break around 3 o'clock, and adjourn today around 5.

Mr. Landry, do you have some comments?

MR. LANDRY: Yes, Madam Chair.

We have some undertakings we would like to deal with. We don't have all of them yet, but most of them. And just so that we have them for the record, first of all, I'll go through them and have the panel speak to them.

I'm going from the undertaking summary in the transcript, and the first one is at page 54, line 9, and that was a letter, Madam Chair, that Yukon Energy filed yesterday, so that undertaking has been done.

The next one is a combination of three. It's page 226, line 21;
227, line 2; and 227, line 8, and it related to an undertaking given to Mr. Keough, and I think Mr. Bowman will deal with that.

ED MOLLARD, previously sworn.

PATRICK BOWMAN, previously sworn.

CAM OSLER, previously sworn.

DAVID MORRISON, previously sworn.

A MR. BOWMAN: Yes. Thank you, good morning, Madam Chair, members of the Board.

The undertaking in question related to actual diesel generation in 2008, and the reference in the transcript, as Mr. Landry noted, was page 226 to 227. But at the time we were working with a table with very small numbers out of Exhibit B-10, which was the April 24th filing, and it is in Attachment B of that filing, and Attachment B-2, to be specific, page 14 of 14, in which the actual diesel generation for 2008 by month by plant was provided.

Mr. Keough had asked for information on five of those entries. One related to the diesel generation in Dawson of 120 megawatt hours that occurred in April 2008, and that generation occurred as a result of the
Mayo hydro plant maintenance that took place during the first week of April, and at the time Dawson was, therefore, required to be on diesel, and YEC also used this opportunity to do transmission line maintenance on the transmission line in the area as well. So the generation at Dawson reflects the fact that the hydro plant was being -- was going through maintenance.

The second entry that Mr. Keough asked about was generation occurring at Whitehorse in May for 175 megawatt hours, and that generation occurred as a result of vandalism, a vandalized insulator on Transmission Line L1-70. This is discussed in the application at page 3-5, lines 6 to 8, and it relates to an insulator on the system. And that amount of diesel is being charged for reserve for injuries and damages, as a result of it being vandalism event. So although it shows up in this table, it doesn't actually go into the diesel expense for 2008.

The third entry that Mr. Keough asked about was October of 2008. He actually went through October, November, and
December. So just to fill those in, October 2008, there was generation at each of Whitehorse and Faro for a total of 219 megawatt hours. And that was due to the Whitehorse Hydro Number 3 governor, which was on October 20th the unit tripped off due to governor issues, and it was at a time when Whitehorse Hydro Number 4 was already out of service. So the diesel generation was required over the following couple of days in order to supply the load, and during that period secondary sales were interrupted as a result of the lack of supply of hydro.

        Sorry, it was out of service because of repairs. The -- because it was as a result of an outage, it would be discussed in the response to Percival 13(a), which lists the outage reports.

        The diesel generation in November, which was a relatively small amount, was 30 megawatt hours, actually relates to two items: the majority of it was a Whitehorse Hydro Unit Number 4 tripping off, and as a result, it was a -- it caused an outage requiring both Whitehorse and Faro diesels to
be run; that was November 12th. And again that one is discussed in response to Percival 13(a), which lists the outage reports. And then a small amount of the fields are in that period, about a third of what's listed for that month, so 10 megawatt hours, was as a result of the connection of the Carmacks-Stewart project. That was where the line was initially being connected for the first time, so there was diesel run for that event. And that was November 5th, and that was just to energize the main line.

December was the majority of the diesel for the year. It was a total of 664 megawatt hours. In the response yesterday I noted that that was due to, in particular, cold weather, which is, you know, more than half of that diesel. And it was a cold period where diesels ran between December 14th and 31st of 2008. There was also an outage on December 1st and 2nd, which required diesel. It's about 300 megawatt hours of the 663. This is related to a failure of equipment at the Aishihik plant, discussed in response to LE-6, a piece of equipment called a pothead failed.
This item was charged to reserve for injuries and damages, or it will be once the project is finally closed out. The repairs for that are still underway. But as a result of it being related to equipment failure, sudden accident equipment failure, as Mr. Mollard noted yesterday. And as I note, the remainder was due to the cold period from December 4th through 31st.

So I believe that covers all the entries that were requested.

MR. LANDRY: And, Madam Chair, the last one for this morning is from page 229, line 14. I think Mr. Osler is going to respond to that undertaking.

MR. OSLER: Good morning.

The undertaking related to Mr. Marriott. It was a question about correspondence, a reference in the opening statement to other correspondence after the Board Order 2009-1. I can confirm that that other correspondence is exhibit -- is the letter from the Board to Yukon Energy, and it's in the exhibit list as Exhibit A-10.

MR. LANDRY: Thank you.
So, Madam Chair, just for the record, that leaves two undertaking, page 257, line 15, and page 262, line 11. And we're hopeful we'll be able to respond to those by this afternoon.

THE CHAIR: Thank you, Mr. Landry.

Mr. Buonaguro, are you prepared to proceed with your cross-examination?

MR. BUONAGURO: Thank you, Madam Chair.

Q Good morning, panel. I'm Michael Buonaguro, counsel for UCG.

Similar to what was indicated yesterday by one of my friends, we also feel that there is quite a bit of material on the record already, so most of my cross-examination is going through and picking up on some clarification points and such, for the most part. And I anticipate -- or I am required by my own plans to be done by lunchtime, because I will be flying out in the afternoon, so I am under my own deadline.

I would actually like to start by picking up on something I noticed
yesterday. A lot of the -- there was some
discussion at various points about amounts that
are held to the credit of ratepayers which are
periodically applied against other amounts in
order to achieve rate stability. For example,
I think the Faro dewatering account, for
example. Do you remember those
conversations?

A MR. OSLER: Yes.

Q It occurred to me that I don't have a handle on
how many of those accounts exist and what the
individual and aggregate amounts being held to
the credit of ratepayers for this purpose are,
and I was wondering, is that something that is
in the evidence already, or if not, is it
something you can provide?

A MR. BOWMAN: Mr. Buonaguro, I'm going
to be a bit careful as we work through with
regard to definitions, just so we make sure
that the two accounts that I talk about are
clear.

At this point in time, in
terms of anything material, the only items that
Yukon Energy deals with are the Faro dewatering
account, which we talked about at some length
yesterday, amounts held, as I noted, effectively to the credit of ratepayers. It serves as a form of no-cost capital to Yukon Energy such that it -- some portion of the assets are effectively being financed by this cash being held, and as a result, the ratebase is lower. And that's one of the ways that ratepayers get a benefit from. And the other is it can be used one time until the money's gone.

But as I said yesterday, it arises from sales of the corporation to the Faro mine site and the people who were in charge of that site at various points in time from the period '98 to 2004.

That amount, my recollection -- it will be listed at Tab 7. It's dealt with in the opening statement, and by the time -- sorry, page 11 of the opening statement. By the time this -- we come forward in this application, it was -- our recollection is 1.1 million is what was there. There is 467,000 looking to be credit against the reserve for injuries and damages.

A MR. OSLER: 463.
MR. BOWMAN: 463,000, and a further 87,000 to deal with the 2008 rate stability issue, as you note. So the residual would be whatever the math works out to there, somewhere just north of half a million dollars.

The only other account that would qualify any way in the definitions you use, but it's a very different type of item, is the diesel contingency fund. The diesel contingency fund is an ongoing trust item. I use the word "trust," because that's the way that effectively it's accounted for. It is an account that's been around for a long time. It was first set up under a different name, the low-water reserve fund. It became a diesel contingency fund in '96, '97. It's amounts held to deal with uncertainties related to water flow, in the event there was a very severe drought. The fund effectively pays for the diesel required to deal with that drought.

In the meantime the cash that's in that fund is invested externally. It earns interest. It will be discussed at each of Tab 9 in the audited financial statements, because it gets specific treatment in there,
and at Tab 3 in page 3-21 to 3-22. There has been no charges to that account for some time, but we know from past experience that in the event of a severe drought, even at the load levels today, it could be required to burn diesel for baseload reasons, and as a result, the fund is still needed for the purpose it was originally intended.

And the rules on that, on those monies, are that it has effectively a trigger at $3 million plus or minus, so that it can actually go to amounts owing to ratepayers, owing from ratepayers, and at the time it reaches $3 million, the terms in the negotiated settlement, '96 - '97, state that at that time, some form of rate adjustment will be dealt with to bring the fund back into line.

Q Thank you.

And if I remember correctly, that fund has something in the order of 800,000 in it right now, approximately?

A MR. BOWMAN: It's -- I have for the number, page 3-22, was .856 million. But as I note, it's externally invested and earns interest, so the balance this month, whatever
it is.

Q Those are the two counts that meet the
definition that I was looking for, right?

A MR. BOWMAN: Yeah, and each of them
meet the definition in a sense that they're
monies or liabilities of Yukon Energy that are
only used pursuant to effectively orders of
this Board or rules established by this Board
in order to address items you note as rate
stability or other things at this Board
determines are suitable.

Q Thank you.

I would like to turn to a
part of the opening statements where you
summarize 2008 actuals. And, specifically, I'm
looking at page 10, where you basically
summarize that the actual ROE for 2008 --
sorry, this would be Exhibit B-12. The actual
ROE for 2008 was 7.2 percent, I guess subject
to auditing the statements?

A MR. MOLLARD: Yes.

Q And I would like to turn to an interrogatory
response. This is the UCG-YEC-1-19. I think
from this point on, I'll just call it UCG-19.
It's just easier for me to say. So UCG-19.
And that's . . .

A MR. MORRISON: I'm getting beaten up this morning.

Q And I have only just started.

THE CHAIR: I was wondering when you guys would catch on to the convenience of the computer.

A MR. MORRISON: We're a little dated.

Q MR. BUONAGURO: So I'm looking at Answer B at that interrogatory, where we asked for the actual ROEs for 2005, 2006, and 2007 compared to the last Board approved; you see that?

A MR. MORRISON: Yeah.

Q So am I to understand that this 7.2 percent that's in the update would fit into this 2008 actual ROE? Is it calculated the exact same way?

A MR. OSLER: Yes.

Q Now, you have in that -- in the same update you talk about the Board-approved ROE of 8.64 percent, which is simply, I guess, the recalculation of the ROE with respect to the BCUC rules that you use plus the risk minus the OIE deduction?
A  MR. OSLER: That is the ROE that Yukon Energy has supplied to this Board for approval in the 2008 GRA. So it isn't approved yet; it's applied for.

Q  Right. But it's based on -- it's calculated in the same way that the last approved 9.05 percent --

A  MR. OSLER: Yes.

Q  -- in the table was calculated?

A  MR. OSLER: The Board approve, in 2005, an ROE based on the same methods derived from the BCUC annual determination of the prospective ROE for the next calendar year, with amounts for risks that the Board determined was appropriate for Yukon Energy and the reduction of a half, 50 basis points, or one half of one percent, that the order in council requires.

Q  Thank you.

Now, in the question we asked you to detail any weather normalization that was going on in your response. I can tell you, I added that to the interrogatory because it is my understanding you can do it two ways. You can report your ROE actuals on a
weather-normalized basis or a
nonweather-normalized basis; is that your
understanding?

A MR. OSLER: I have never
undertaken -- I have never heard that we would
be reporting anything on a weather-normalized
basis.

Q Let me try this. These are not weather
normalized, as you indicate the answer, right?

A MR. OSLER: The ROEs?

Q The actual ROEs that are reported in this
table, you have done nothing to, from your
perspective, weather normalize them?

A MR. OSLER: Correct.

Q So --

A MR. OSLER: I'm not even sure how we
would do it, but never mind. But no, the
answer is simple. It's not been weather
normalized.

Q Now, that means that the actual results that
you are reporting here may be over your ROE,
your Board-approved ROE from 2005, or they
might be closer to it, based on abnormal
weather in those years.

So, for example, in 2006,
the 10.59 percent ROE that you are reporting there, that's actual results, and that's based on the actual weather that was experienced in 2006?

A MR. OSLER: Yeah.

Q Which means that if, in theory, I don't know, but it could have been that in 2006 you had abnormally wet and cold weather, which means that you had abnormally high throughput, which means that your revenues would have been abnormally high because -- is that possible?

A MR. OSLER: Yes, it's possible, but -- and we used, I notice in the answer, that we have to take responsibility for having got you on the weather-normalization theme.

Yes, these can vary year by year because of the effect of weather on sales. And if there was a very cold period and there was a lot of extra sales -- we didn't have to incur because we have still got surplus hydro, we didn't have to incur any material increased generation costs, then the returns would tend to be a bit higher.

There could be a lot of other factors. Anything else that pushed sales
up beyond what we had forecast would tend to have that effect, even if it wasn't weather, just bigger growth than people expected, or reductions in costs compared to what we had anticipated, things like that.

So a lot of other things could contribute to this result, and you would have to go through an analysis of each year to understand what caused what and how important was each factor.

Q Okay.

So and if we're going back to 2006, if you wanted to account for how much of that deviation from the Board-approved was as a result of abnormal weather, that process would be weather normalization? It would be accounting for the increase or decrease relative -- or responsible -- sorry, caused by abnormal weather and deducting that or adding that back on to the actuals to weather normalize it?

A MR. OSLER: If one was trying to figure out the impact of weather, you'd have to be able to determine what the sales would have been at something called, you know, "normalized
"weather" and how much that affected your generation costs and your revenues. And then you could determine -- you could say that in that particular year, this portion of the difference is due to that factor.

Q And I take it from the way this conversation is going that that's not something that YEC does or normally does --

A MR. OSLER: We don't.

Q -- in reporting its actuals?

A MR. OSLER: No.

Q Thank you.

A MR. OSLER: Part of it, not only do they not normally do it, they don't normally get into, even when looking at sales on a forecasting basis, the normalization process, as you have heard in other answers. So it's not as though they have a weather-normalized number sitting in their closet and they can haul it out for this purpose, because there is a lot of -- there's all the factors that went into why they don't do that even for forecasting that would have to be brought to bear.

Q Thank you.
Now, just to close this off, YEC, as I understand it, takes on what I call the "weather risk" in its forecast.

A MR. OSLER: Generally speaking, yes, and it takes on all other risks relating to forecast.

Q Right.

At the same time, though, you are forecasting, you are not forecasting, as you said, on a weather-normalized basis?

A MR. OSLER: No.

Q Okay. Thank you.

Now, in the Part (c) of this response, we asked about multiyear performance-based regulation. And the answer, in part, and the part that piqued my interest was the last sentence of Part (c) (quoted):

"Yukon Energy has not assessed measures that the Yukon Government might adopt to bring in legislation or policy related to performance-based regulation."

Do you see that?

A MR. OSLER: Yes.

Q Now, that suggested to me that YEC might have
the position or understanding that unless the
Yukon government specifies or requires
performance-based regulation or implements some
sort of policy related to that that you were
prevented from entering into performance-based
regulation. Am I incorrect in that?

A MR. MORRISON: Madam Chair, we would, in
thinking here, would just be talking about our
impression that within the YUB Act that this --
this ability didn't exist, but whether it does
or not is, you know, is not -- you know, we're
not -- we are just giving what we thought.
Whether it is, we might be proven to be wrong
on that, but . . .

Q Okay.

Now, the beginning of
this interrogatory we quoted from the resource
plan, the second reference, and it's part of
the directions from the Board to YEC. And
you'll notice that they talk about full cost of
service, rate design, an update to electric
service regulations. It also talks about
maximum company investment. And these, the
ones I have just mentioned, are all things that
appear in your letter to YECL, Exhibit B-13?
A MR. OSLER: Is the question are all these types of things cover in the letter?

Q Yeah, I'm asking to confirm that all those things are in the letter.

A MR. OSLER: Let me just check.

Well, certainly the issues of doing a joint full cost of service and addressing rate design matters that flow from that, update to electric service regulations are all covered.

Q Right.

And I think even in paragraph 2 you talk about maximum utility investment?

A MR. OSLER: Yes, maximum company investment, which is part of the Electric Service Regulations, would be covered.

The performance-based regulation mechanism in the middle is probably a different thought process that really deals much more with what we're in today.

Q You anticipated what I was going to ask.

A MR. OSLER: Sorry.

Q That seemed to be the one thing that you weren't suggesting to YECL that you considered,
and you said a "different thought process."

Maybe you can explain why that particular
suggestion from the Board was omitted from this
letter.

A MR. OSLER: Well, we didn't have this
in front of us when writing the letter. But
the letter was based in the context of,
Madam Chair, the issues of what people have
called Phase I and Phase II, which is a bit
different terminology than we were used to.

But going with that
terminology, Phase I would be the type of
exercise required to review the revenue
requirement of each utility.

Q Well, in --

A MR. OSLER: In that sense,
performance-based regulation mechanism could
mean the ROE type of approach and certain ways
of setting revenue requirements such that they
could be adjusted based on performance.

They might mean other
things as well, but if they meant what I just
said, they would be part of the
revenue-requirement thought process.

In terms of Phase II,
you'd be saying, Okay, having given discussions
of the revenue requirements of each utility,
how would that work its way through a joint
cost of service, and how would you design rates
on a consolidated basis, and what would be the
joint electric service regulations for the two
utilities, more to do with how do you recover
their costs through rates and all of the issues
relating to that.

There may be a
performance-based element to that that's not in
my mind at the moment. If there is, it should
be cover in the joint discussions that we are
planning with YECL. But the thought was, we
are dealing with what everybody asked us to
deal with, which was the Phase II type of
exercise, the way I have just described it.

Q  Although going back to B-13, the letter, on the
second page, the last paragraph, you do talk
about -- or the company talks about (quoted):
"...in the interest of controlling
future regulatory costs in the Yukon,
we will need to examine potential
future options where YEC and YECL once
again can work together, as in the
1996/97 (and earlier GRAs) to address revenue requirement, cost of service, rate design and all other related matters in a single integrated hearing process."

Which suggests to me that you will be talking to YECL, or you are proposing to talk to YECL, about your next rate proceeding and doing a joint basis?

A MR. OSLER: Yes, Madam Chairman, in that sense you are quite correct. All of these topics would be covered in that part of the conversation.

Q When you say all these topics, that would include the possibility of putting forward some sort of incentive-based regulation?

A MR. OSLER: Well, Mr. Morrison?

A MR. MORRISON: No.

A MR. OSLER: If you were talking about jointly filing at the same time, revenue requirement matters, and finding areas where you could facilitate cost-effective regulation and keeping life simple for everyone who has to deal with it, there would be a checklist of topics. One of them would probably be, because
since the Board has asked about it, What is the company's approach in each case to performance-based regulation?

The companies might -- as I said yesterday, the fact that two utilities get together to try and do this doesn't mean they're going to agree on everything.

Q I'll take that point.

A MR. OSLER: So a list is a list, and you see what you can do with it, because the Board has asked you to see what you can do with it. That's as far as I can go.

Q I just want to confirm that it will be part of the conversation. What the results will be, I guess you will find out later?

A MR. OSLER: Mr. Morrison?

A MR. MORRISON: That's correct.

Q Thank you.

I have just a couple of small questions about cost of debt. There was some extensive cross-examination yesterday on cost of debt; I don't want to repeat any of that. I did want to clarify a couple of things, though.

First of all, almost all
the debt, and I think the plan is for all the
debt going into the future, is between YEC and
YDC, right?

A MR. MORRISON: I can't confirm that,
Madam Chair.

Q What part of it can't you confirm?

A MR. MORRISON: Well, all the debt going
into the future is going to be between YEC and
YDC.

Q Okay.

A MR. MORRISON: We can't -- you know, I'm
not prepared to indicate that that's the case.
We may have to borrow externally. I have no
idea.

Q So in terms of when you do obtain debt from
YDC, is there comparisons made on a regular
basis to what's available from third parties?
Is this part of your analysis?

A MR. MORRISON: Yes, Madam Chair. We
have -- in my recollection, somebody -- one of
my colleagues on the panel can be more
specific, but we have -- my recollection is
there is an established mechanism for a debt
rate at which we must borrow from YDC so that
it is competitive with the market.
And we always look at the market and see where we can get, if it's cheaper or we can be competitive, we'd look at alternatives. But my recollection is that we have to borrow from YDC at a competitive market rate.

Q I think that's my understanding too. There is an actual formula that figures out a base rate, and it adds 120 basis points to it, and that's the rate that you have to borrow from YDC. And I think what you are telling me is that at any point in time, when you are looking to borrow money, you calculate that rate, assuming that YDC has the funds available to lend, which is required, and then you actually do and compare it to the availability of third party debt to see if there is any favourable?

A MR. MORRISON: We do. We constantly check the market. We have, you know, I would say, these days a relatively close relationship with our banker on the YDC side and the YEC side, so . . .

Q So from that can I infer that whenever we see a debt instrument in the evidence between YEC and YDC, is it true, then, that the company, at
that time, reviewed third party -- the
availability of third party debt at less -- or
at more favourable terms and determined that
they weren't available?

A MR. MORRISON: Madam Chair, I can only
speak for a period of time where I have
knowledge, and so we're talking about some
instruments that are older than my tenure. I
have no knowledge of that.

But during my tenure
here, we have looked at the market. We
actually, a few years ago, refinanced all -- a
lot of the debt that was on the books, because
specifically there was high-interest loans out
there, and we were able to get them down to a
lower interest rate.

So we have gone through
that exercise fairly recently, within the last
three or four years, pretty extensively. The
cost of the debt was pretty high over the last
few years. It started to come down again. I
know in the public's -- or there's a perception
out there that at zero or half a percent or
one percent bank of Canada rates that debt is
really cheap. Certainly not our experience in
recent months, talking to our bankers that it's really cheap. It's anecdotal, and I know we are looking for information in response to an undertaking that will be more specific. But last discussions we had with our banker, they are talking about 6 1/2, 7 1/2 range of debt, and that's not tremendously cheap, from our point of view. Although -- you know, we have a perception, and we think that there's cheaper money out there, but it's not that cheap.

Q Okay. So if I can call it this practice of comparing the available rate from YDC to the market, when appropriate, I expected that that's not something that's been elevated to a written policy.

A MR. MORRISON: No. No, Madam Chair.

Q But it would be something you would consider to be part of your unwritten policy?

A MR. MORRISON: I would consider it -- what we do is we look at things from a fairly practical point of view, and we look at things in the best interest of the ratepayer and where we can get the best option of the ratepayer.
So we do that as part of our normal course of business.

Q Thank you.

Now, in the evidence you were asked to produce the actual policy that sets out how you borrow from YDC, and I don't -- I can't -- I don't have the reference on me, so I'm not going to take you to it, but I did notice one clarification in the interrogatory response which I found interesting, and I just wanted to understand why this once.

In the actual policy, the idea was that the interest rates that you borrow from YDC at would be recalculated at every GRA, do you recall that part of the policy? And then there is a qualification in the interrogatory response that that is not the case because of certain concerns?

A MR. OSLER: Well, I recall the discussion way back that that was what some people thought the policy meant, and I recall getting it clarified that that definitely wasn't what the board of directors meant, and there was a need to clarify to this Board, I
think at some point in history that point. '92, my colleague tells me.

So I recall that discussion in history, and the board -- I recall being at the Board of directors meeting way back then, and that certainly, in the board's mind, was very clear, they weren't planning to have it redone every time, and eventually that point was made clear to this Board.

Q While you were talking, I found the reference, so I thought maybe to be clear, it's CW-26. It says, at Answer (a) (quoted):

"The attached financial policy was approved by Yukon Energy's Board at the December 18, 1992 meeting. Note that at the time this policy was written, it was the intent to adjust the long-term interest rates periodically (at each GRA). However, YEC's Board later updated this component at the July 12, 1993 meeting to ensure the rates were locked-in over the long-term, in part to address a concern arising at the 1993/94 GRA."
So I'm just interested in why that -- it seemed like a very specific shift in policy, and I'm just wondering if you could explain what that concern was.

A MR. BOWMAN: Yes, I can go through that a bit.

This policy -- Mr. Osler said he was going to speak to history, but when Yukon Energy was initially set up, the intent was to try to maintain a 60:40 debt-equity ratio, for the reason that that ratio keeps the equity levels lower in the company and, as a result, leads to lower overall rates for ratepayers.

The mechanism to do that wasn't in place at the time. That mechanism wasn't fully worked out until 1992, in the policy that you see before you.

The policy was approved by the Yukon Energy and Yukon Development Board in 1992. As a result of adopting this policy, a particular debt instrument was set up at that time for, my recollection was, $18 million.
Dominion Securities about the appropriate rate for doing that type of debt. That study was filed with this Board, and it was a matter of significant review during the '93/94 GRA.

In that GRA one of the intervenors, my recollection is the City of Whitehorse, one of the intervenors expressed concern that the debt, as established, may not fairly represent terms consistent with proper long-term debt, because it had this sort of resetting interest rate component of it. And there was -- the IR asked for the policy, and it references the policy and the subsequent adjustment to the policy.

There was also a fair bit of argument at that GRA. There was an argument from the City of Whitehorse and a reply argument in the companies where it was made very clear that the intent is that this debt between the two companies mimic long-term -- any long-term debt available through the market, that it contained provisions that were consistent with long-term debt that would be available from the market, or at least no less favourable, and that it would provide a means
to maintain Yukon Energy's equity levels relatively strictly at 40 percent, so that they didn't drift higher and, as a result, cause our rates to be higher than they would need to be.

So that is the other side of the story, which relates to the regulatory review side of it, that isn't in this IR, because it was asked more about the policy side.

Q Thank you very much.

I'm going to switch now to another interrogatory response. This is UCG-35. And I would like to start with the answer to (a), which is a table that shows labour cost increases and labour charge, capital and deferred projects.

A MR. OSLER: Yes.

Q Now, I just wanted some help in how I am to understand how to read this table. So at -- the first three lines are "O&M labour," "admin labour," and "Labour expense." And with labour expense being the total of O&M and admin, and then it shows the numbers for 2005 to 2009.

And as I follow it down to the bottom of the page, at the bottom of the
table, it has several, I guess, distributor.

It says (quoted):

"Yearly increases as %
Economic increase January 1st each year
Number of new positions added
Number of positions cancelled."

So the way I look at this, and perhaps you can confirm whether I'm right or wrong, is that, for example, when I'm looking at the labour expense, or I guess the total for 2006, of $7.848 million; you see that number?

A MR. OSLER: Mm-hmm.

Q I am looking at the increase in 2007 to $8.395 million. The explanation for that increase is partly because of an economic increase in January 1st of 2007 and partly as a result of three positions added? Is that essentially how I'm supposed to read that?

A MR. MOLLARD: That would be the majority of it. There may be other smaller components; for instance, if benefits increased, that would also increase our labour costs. But those two factors would be the
major contributors to the increase.

Q Okay. So again, sticking with 2007, so for the 7 percent total increase as a percentage, approximately 3 percent of that would be due to an automatic adjustment, this economic adjustment, and then the rest was subject to what you're talking about, the other smaller amounts, I guess, that would be factored in, the rest of it would be the three added positions?

A MR. MOLLARD: Yes, that would be correct.

Q Now, this economic increase each year, is that -- I'm going to hazard a guess. Is that something that would be built into the collective agreement and then carried over into the people who are not part of the collective agreement? Is that how that operated?

A MR. MOLLARD: That's correct.

Q And the 3 percent -- I see 2006 is 3 percent; then 3 percent 2007; 3.75 and 3.5. Presumably those are all embedded in the collective agreement?

A MR. MOLLARD: That's correct.

Q I haven't checked this, but is that -- are the
actual numbers embedded in the agreement, or is that a calculation based on certain economic factors each year?

A MR. MOLLARD: The percentages are in the agreement.

Q So 3 percent for 2009, you are "stuck with " as a result of the collective agreement?

A MR. MOLLARD: That agreement has been signed, yes.

Q Sorry. That's -- I said 3 1/2. Sorry, I said the wrong line there. Okay.

Now, there's no -- oh, no. I'm sorry. Skip that.

Now, going to, then, Part (b), you were asked to provide a bunch of tables showing the -- for people who had compensation over $100,000 in each year, so 2005, 2006, 2007, all the positions that had salaries over $100,000. Sorry, compensation amounts over $100,000.

A MR. MORRISON: Total compensation, just to be clear, Madam Chair. Total compensation.

Q Right.

I think maybe part of what you described to me may answer this, but
I'm going to take an example so that you can explain it to me. And I can't help myself. I'm going to take the president and CEO. For 2008 and 2009 and just compare them.

So for 2008 the amount is $204,521.30 total compensation, and the 2009 forecast amount is $223,542.55. Do you see that?

A MR. MOLLARD: Right.

Q So as a strict percentage, that would be approximately 9 1/2 percent, I think you can take subject to check.

A MR. MORRISON: Maybe I'll just answer my own question, okay?

Q Feel free.

A MR. MORRISON: Okay.

Q And so as I understand what we have been talking about, part of that is a 3 1/2 percent automatic increase to salary; is that right?

A MR. MORRISON: Yeah, Madam Chair, I understand what my -- Mr. Buonaguro picked mine, but mine's not a good example. It's done differently. I have a separate contract. I think we explained that in interrogatory, but it doesn't work the same as everybody else's.
Q: So do you have a different escalator between 2008 and 2009?

A: MR. MORRISON: Well, and I think we explained that mine is done -- with the board -- especially for 2008 and 2009, my contract was looked at as in a hay plan performance-review process and it has very different elements. It certainly -- you know, it's just more difficult to explain. If you wanted to try to do a comparison of apples and apples, it's better to do anyone else.

Q: So there's an interrogatory response in there somewhere that explains that?

A: MR. MORRISON: That's correct, yes.

Q: The one example I picked.

A: MR. MORRISON: Yes.

Q: So if I go through any one of the other ones, that would be generally the explanation, would be 3 1/2 percent plus or minus, I guess, an additional amount, possibly, due to variation of benefit amounts?

A: MR. MOLLARD: As well as overtime for the union contract employees.

Q: Okay. Thank you.

Q: Now, in Part (c) of that
same interrogatory, which you have to go back from these tables, I think, we asked for a table that shows the "Average OM&A costs per customer." You are at that table? Okay.

A MR. MORRISON: Sorry, Mr. Buonaguro.

Q It's UCG-35, and it's Part (c).

A MR. MORRISON: Yes, thank you.

Q And there's a caveat where you say "Average OM&A costs per customer are provided as requested," and then I'll just paraphrase. Basically, you are saying but because YECL is one customer, which is much, much, much larger than the rest of the customers, the results don't actually have any meaning, something along those lines, right?

And we asked in this part of the procedure relating to the hearing if you could do the weighting and that didn't happen. Is the weighting process as simple as, for example, if we wanted to fix the column for actual 2005, where we have "Total customers* 1,786," would we basically take customer number, 1,786, which is YECL, figure out how many subcustomers are in that for that customer, and add that amount to the total, and
that would get to the number that we're looking for?

A MR. BOWMAN: Mathematically, if you were just looking to put a number in the numerator that was YEC's costs and a number in the denominator that was all Yukon ratepayers or all Yukon customers, that would get you to a number. I would have some questions or concerns about the meaning behind such a number, given these type of costs-per-customer ratio is typically linked to utilities whose costs are driven by the number of customers they have. At generation level, customers are not the thing that drives costs within Yukon Energy.

So if you wanted to come up with a metric, I presumably that would be the way one could come up with a cost-per-customer number that was driven down to the lower levels. I don't know what meaning one could ascribe to it.

Q Well, you talk about weighting in the response. Do you have a different way of weighting it that YEC felt would be meaningful?

A MR. BOWMAN: Well, there's -- there's
lots of different ways people try to turn their minds to metrics like this. In a cost-of-service study example -- for example, one will sometimes see that when you are allocating customer costs, general service customers get a bigger weighting than a residential customer, and a wholesale customer would be a different story all together.

So there's lots of different ways to do it. It depends on what you're trying to use it for. And as I say, in a utility where the bulk of the costs are generation and transmission, a divisor that's based on number of customers would not usually track or not usually be a metric that reported anything that's of particular note for the generation system. It's not -- you know, adding -- adding a customer at Minto mine versus adding a customer at a house do not drive the same type of costs on a generation-level system.

So I think that's why you don't normally see generation level costs as opposed to, say, distribution costs design to follow a cost-per-customer type of metric.
Q Is there a way that you can take out YECL, like, and have it -- and have -- I mean, you seem to be telling me that you can't -- you can't provide any meaningful metric that shows what you were spending on OM&A per customer. I find that hard to believe.

A MR. BOWMAN: I think the problem we're running into, Mr. Buonaguro, relates -- just relates to a general understanding of the -- of the way that the system works in Yukon, where Yukon Energy is basically a generation and transmission utility. It serves some customers, but they're by far the minority in Yukon, 10 percent.

So the costs from adding customers tend to be distribution-related costs, and they tend to link reasonably well for distribution-level changes in revenue requirement, and that's why distribution companies will often try to go to a metric of cost per customer.

Generation-level companies don't usually use that type of metric. They usually use different types of performance metrics, similar to some that
Yukon Energy tracks. And they of course have their own sort of story embedded in them, cost per kilowatt hour generated, let's say. That has its own issues related to when you have a system of surplus hydro.

But, nonetheless, those type of metrics track generation-level costs, at least, or costs per kilometre on a transmission-level system.

Cost per customer are typically more a distribution-level type of metric, so you're effectively taking one type of number, a generation and transmission cost in the numerator and another type of number, the number of customers, the denominator, and they don't mesh really well. That's all I'm getting at.

Q All right. So you mentioned as part of your answer the metrics that YEC actually tracks, presumably because you find that those metrics are meaningful?

A MR. BOWMAN: Well, Yukon Energy does have certain key performance indicators that are filed with this Board, and I believe Yukon Electrical has its own, and they come out
of much earlier discussions before this Board. They come out of a time when the two utilities were managed jointly. So whether they are perfectly aligned to a generation company as opposed to largely distribution company, I can't say. It's not something a have spent a lot of time on recently.

But costs per customer of this type is -- you know, wouldn't be one that probably carries a lot of meaning is --

Q So, again, when you talk about the metrics that Yukon Energy Corporation tracks, and you said you file with the Board, is everything you track already in the evidence?

A MR. BOWMAN: There is an annual KPI report filed with the Board. It's pursuant to the template that was set out by the Board, but it's a public document.

Q Is it filed in this proceeding?

A MR. BOWMAN: I don't recall that it's filed in this proceeding, no.

Q Perhaps you could file it in this proceeding, the most recent.

A MR. MOLLARD: Sure.

A MR. BOWMAN: That's fine, yeah.
Q Thank you.

A MR. BOWMAN: It's a public document, yes.

THE CHAIR: Just to be clear, Mr. Buonaguro, you are asking for what year, the most recent KPIs?

Q MR. BUONAGURO: I would expect we would want the most recent one, and then I am assuming, and maybe I'm wrong in assuming, but that that would show relative to previous years' filings how performance has changed, or am I completely wrong?

A MR. MORRISON: Madam Chair, if it's helpful, could we give you a year or two back?

Q That would be good. Since we are basically dealing with a gap between 2005 and 2009, we would get whatever you have for those years, that would be fine. Thank you.

A MR. MORRISON: That's fine.

Q Thank you for the clarification.

I would like to turn to UCG Number 38. And, in particular, I'm looking at Attachment 1, which is response to Part (b) of the interrogatory.

And on this particular
table, which is "TOTAL HONORARIA PAID TO YEC BOARD MEMBERS FOR 2005-2008." We noticed a significant jump with respect to the chairman between 2007 to 2008, from $38,200 to $57,197. So I was just wondering if you could explain why that particular position increased by, I think it is, something in the order of 30 or 40 percent in the one year.

A MR. MORRISON: Madam Chair, just can you just give me a minute? I just want to check something.

Madam Chair, if I'm --
I'll check something at the break, just -- but let me try to answer now, and I'll check it, and if I have something to add to it, hopefully I can add to it again for Mr. Buonaguro.

Generally, the chairman's fees are simply based on the amount of work that he does. So he's involved in a number of different things that he does. As you can see, obviously a lot more work than chairing meetings.

And a big part of what he does is dealing with -- it's the chairman's job
to deal with the Minister, senior government officials on issues relating to the corporation. He, in our case, has some specific expertise that we utilize, and so he's very helpful on a number of matters, including some of our water-related issues and First Nation relations and public meetings that we use him to go to. So there's a big jump.

What I'm getting at is the board -- board fees changed in -- and I can't remember whether it was 2006 to 2007 or 2007 to 2008, so part of it may be because some of the board fees increased, and I'll check that and just confirm, if that's all right.

Q When you refer to "board fees," like fees for particular --

A MR. MORRISON: For meeting fees.

Q I see.

A MR. MORRISON: Their remuneration for per diem for --

Q I see. Like a tariff of some sort.

A MR. MORRISON: Yes.

Q I could appreciate the clarification, if we could get that as an undertaking.

A MR. MORRISON: I'll do my best.
Q  And then -- okay.  

So, basically, looking at that table, between 2005 to 2008, it just so happens that between 2005 and 2007, subject to changing the tariff, the activity was relatively stable, and then in 2008 the activity went -- presumably there was increased activity and that the chairman was then charging or, I guess, docketing more time on more different things and, therefore, incurring more fees; is that generally the explanation?

A  MR. MORRISON:  Yeah, that's generally the -- I mean, the amount of work that he does, it seems like it's been pretty steady, although the difference between 2006 and 2007 is, you know, $8,000. So it depends on what -- you know, what kind of level of activity we have going.

And in 2008 we were building the line, and there was a lot of other activity underway, and the chair is pretty actively involved.

Q  Now, the -- my understanding is that there is an order in council that sets the YDC chair's remuneration at 38,000? Not YEC but YDC?
A MR. MORRISON: That's correct.

Q Can you explain the difference between what the YEC chair does and what the YDC chair does.

A MR. MORRISON: The YDC and YEC chair do very similar things for their respective corporations: chairs meetings; undertakes, you know, briefings for ministers. Just given corporation, does the same things.

Q Thank you.

I'm going to turn briefly to UCG Number 94.

A MR. MORRISON: Sorry, 94?

Q Ninety-four.

This undertaking refers to the costs of the out-of-court settlement with respect to Mayo-Dawson transmission. And, in particular, we just wanted to confirm that the numbers at Part (b), do you see those, "Internal Labour 17,758," for example?

A MR. MORRISON: Yes.

Q So that, internal labour costs, would have been deducted from the labour costs that we referred to earlier in, I think, the table at 1-35, UCG-1-35. Has it been accounted for in that way?
I ask because internal costs would be something that somebody's already getting a salary for, and then I'm assuming that you've -- you've allocated an amount of their time to this particular task and then deducting that from your basic revenue requirement. That's what I am assuming is happened. I am trying to confirm that that's in fact what happened.

A MR. MORRISON: If you could just give us a second.

A MR. MOLLARD: Can you repeat the question so we answer the right thing.

Q Sure.

So looking at Part (b), you have identified all the different cost categories for the claims process. And then in Part (c) you have said that these costs are not allowed in regulated operations and so are excluded from this application.

So the first area of clarification was to confirm that the internal labour, which I have assumed is money that's being paid to internal staff already and, therefore, needs to be deducted from revenue
requirement in order to actually exclude it from the application, to confirm that that was done; that's the first part.

A MR. MOLLARD: There are no amounts in 2008 or 2009 revenue requirement that relate to this settlement.

Q What I'm trying to confirm, that that means that there was an exercise where somebody's salary -- like, presumably internal labour of $17,758 means that somebody in terms of the company whose salary is part of your overall revenue requirement, part of that time was allocated out of the revenue requirement. And I just want to make sure that that happened.

A MR. MOLLARD: Just to be clear, Mr. Buonaguro, the internal labour charges that are recorded in UCG-94 (b) were all incurred prior to 2008.

Q I see. So that means that the only, I guess, usefulness of those numbers in terms of evaluating 2008-2009 is with respect to -- I guess there would be 2007 that that number would have been included?

A MR. MOLLARD: Claims go back to, I believe, 2005, so . . .
Q Okay. So to the extent that they would have been removed from revenue requirement, they would have been removed in 2005, 2006, 2007, somewhere in there?

A MR. MOLLARD: They would have been taken out in -- in previous years of '5, '6, and '7.

Q Thank you.

For the rest of the expenses, I think you are saying that they were just never add -- are you saying they are also out of period, they are not 2009 costs?

A MR. MOLLARD: As the settlement occurred in 2008, there would have been some 2008 expenses. Those expenses were never included in the revenue requirement before us.

Q Thank you.

At UCG Number 46 we asked about payment in lieu of taxes. And I just have a very simple question: We were trying to figure out where exactly how it is that you are required to do that and the process that's required. We looked, for example, in the Assessment and Taxation Act and couldn't understand if that was what was directing you...
to do payment in lieu of taxes.

Can you give me a summary

of how your payment in lieu of taxes is done

and under what act?

A MR. MOLLARD: If you give me a second,

I just want to review the IR.

Q Sure. It's UCG Number 46.

At Part (e) we've said

(quoted):

"Please provide documentation

outlining YEC's requirement to make

payments in lieu of property taxes to

municipalities."

And the answer at

Part (e) was (quoted):

"Yukon Energy is owned by the YTG and

therefore it makes payment in lieu of

property taxes to municipalities

instead of actually paying property
taxes."

And we just wanted a

little more understanding of where that

requirement comes from, that's all.

A MR. MOLLARD: So the

payment-in-lieu-of-taxes requirement,
Madam Chair, comes from the Yukon Assessment and Taxation Act.

Q That's what we thought, but I guess -- and maybe it's just a -- is there a particular section I should be looking at?

A MR. MOLLARD: I believe I have a reference, if you just give me a moment.

Q Sure.

It's not something I need right this second. If you want to do it at the break or by way of undertaking, that's fine. I don't want to dwell on --

A MR. MOLLARD: Sorry, I have found it.

Q Okay, great.

A MR. MOLLARD: It is sections 63 (1), 64 (2), and 66.

Q Thank you.

Now, we asked you some questions, or at least one question, about the wind turbines used for generation. Particular UCG Number 30, we asked for the production numbers. And I don't have actual questions specific to production, but I just wanted to reference that as where we asked about wind turbines.
Can you tell me, with respect to ratebase, what, if anything, is in ratebase for the test years with respect to wind turbines?

A MR. MORRISON: operating costs or capital and operating?

Q Well, I'm going to ask about both. So at ratebase there would be or should be something, or not, depending on whether it's been depreciated, depending on how it was paid for. I'm just trying to confirm what part of ratebase, first of all, is related to wind turbines?

A MR. MORRISON: I have -- Madam Chair, I would have to get the number. It's not a number I have at the top of my head.

Q Okay.

A MR. MORRISON: Just in -- for the record, though, one of the wind turbines was paid for by capital contribution. So I think we've had this discussion previously, and we'll dig out the numbers.

Q I think you anticipate the second part of the question, the O&M costs, I guess, per turbine.

A MR. MORRISON: We'll -- I think we'll
have to do the same, Madam Chair.

Q Okay. Thank you.

And then as part of that undertaking too, if you could, for the O&M costs, if you could relate that to the kilowatt hours produced or anticipated reduced, I guess, over the test period 2008-2009, so we get a sense of how much you are spending OM&A per kilowatt hours for that particular area of generation. Thank you.

A MR. MORRISON: Yes.

Q Now, I would like to talk a little bit about customer complaints. Not that I have a particular complaint, but rather the process that's involved with respect to making customer complaints.

My understanding is that the Electric Service Regulations, for example, don't address a complaints process, but rather the complaints process is through the Public Utilities Act -- part for the Public Utilities Act; is that correct?

A MR. MORRISON: I'm not sure.

Q You're not sure?

A MR. MORRISON: I don't know the answer
to that. I can certainly find out for you, if you would like.

Q I think that's true, but let me put it this way, then: From YEC's perspective, what do you do to facilitate the reporting and resolution of customer complaints with respect to this service that YEC provides to its customers?

A MR. MORRISON: Well, we -- A) we take customer complaints and look at them and make every attempt to resolve them. I can't recall any that have been, at least in the recent while that I have been around, that we have any that have been resolved to a higher authority to be -- to be dealt with.

Q Now, in terms of --

A MR. MORRISON: And, sorry, and Mr. Mollard would like to jump in.

A MR. MOLLARD: Just if I can add to that. We do -- customer services is in my area, so my front-line staff usually get the first-line complaints, and we have an escalation within the company that we go through if customers are dissatisfied with the response they get from front-line staff. They will elevate to a supervisor, to a manager, to
myself. And if at that level they're still not satisfied, I generally will refer them to the Utilities Board to forward their complaints.

Q Now, in terms of this process, in particular with respect to escalation and the ultimate potential reference of the Utility Board, is that something that's -- well, first of all, is that something that's documented? Is there a policy with respect to that?

A MR. MOLLARD: There is not.

Q So as a customer entering into that process, if I have a complaint, then I call up YEC, there is nothing in writing that I may have been able to see in advance to understand what the process I'm about to enter into is going to be like?

A MR. MOLLARD: Outside of the Utilities Act Rules, there's not.

Q And in terms of customer communication, do you put anything out there to your customers to explain that they have this process available to them?

A MR. MOLLARD: We're pretty clear that -- I mean, we try as much as possible to indicate to customers the contact available to
them, to the company, so that there's multiple
ways via email, our web blog, and via our
customer service hotline; they can get in touch
with us if they have an issue.

Q Okay. But beyond the notice as to, You can get
a hold of us here if you have a problem, I
guess which I presumably --
A MR. MOLLARD: Yeah.

Q Is that through advertising or through billing
services or --
A MR. MOLLARD: It would be on our bills;
it would be on all our communication.

Q Beyond that, the process is something which
is -- I'm going to call it "informal," only
because you don't have a written policy; is
that fair?
A MR. MOLLARD: I would agree it's not
written.

Q Would you agree that it's informal?
A MR. MOLLARD: It's well understood by
the people that are -- that are involved in it,
if I could say that.

Q When you say "involved in it," you mean from
the perspective of the company?
A MR. MOLLARD: Correct.
Q  As opposed to the people who are complaining?
A  MR. MOLLARD: I can't presuppose what they would understand.
Q  Okay. Thank you.
I would like to ask you
some questions about Rider J. We asked about
it at UCG Number 14, for example. Now, this is
the -- this is the rider that, I guess the way
I have understood it, replaces lost revenue
from the Faro mine; is that a simple way of
putting it?
A  MR. OSLER: That would be a simple
way of putting it.
Q  And throughout the interrogatory responses, I
note that you have been very specific that it
covers both recurring costs, so costs that have
been recurring since the mine left or closed
down, but also one-time costs, from --
A  MR. OSLER: What you said the first
time was that it deals with the lost revenue
from the shutdown of the Faro mine. And today
that's essentially what Rider J, in simple
terms, is doing.
Initially, when it was
first instituted, it had some other functions
as well, to do with what you're calling
"one-time costs." But Yukon Energy came to the
Board when those one-time costs had been
amortized and completed and requested that the
rider be reduced to reflect the fact that those
were no longer appropriate. So I forget the --
about 2003.

Well -- and Mr. Bowman
reminds me, the Board, on an interim basis, has
recently reduced it to do with the revenue
reductions that the company has brought forward
in this application. So we're moving further
and further away from the relevance to the Faro
mine.

At the moment I think the
history is less relevant than the reality that
this is a method for collecting revenue, until
such time as somebody goes through the process
of adjusting rates to not need the rider. The
rates have to go up; the rider could go away.

You have just seen the
same thing happen, Madam Chair, with the
Rider F. I mean, since the two utilities were
before the Utility Board in '97 and had GRA
rates fuel price forecast then, we have not had
the opportunity for both utilities to be
brought whole in terms of fuel costs into their
revenue requirements until YECL was before the
Board last year.

Now that YECL's revenue
requirement has been determined, it includes
fuel price that are up to date, so to speak.
And as you have seen, the Rider F has now gone
to zero.

And, you know, there's a
proposal in compliance with Order 2009-2, a
proposal as of January 1, 2010, to increase --
put in a new rider of 10 percent in order to
recover all those fuel costs plus a little bit
more that the Board has allowed.

So, essentially, Rider J
is the same type of thing. It was an interim
measure that the company proposed to the Board,
the Board approved in 2008 as a quick way to
deal with the closure of the Faro mine, in a
simple, expedited manner. But we never
contemplated at the time that we did that that
this would be around this long, okay?

There was a general
expectation in the atmosphere in 1998 that we
were just about to have another GRA. So
that's -- forecasting is not always an exact
science.

Q Thank you. I found that quite useful.

So, I mean, it sounds

like I hit the nail on the head with my simple
summary of it, which is that really it's -- it
represents a portion of your normal revenue
requirement, not related at all to costs
anymore with the Faro closing, but rather costs
that would normally be allocated across all
classes based on the cost allocation, but since
you don't have an up-to-date cost allocation.

And I also because

presumably you are restricted through OIC from
increasing costs, for example, to industrial
customers, that you use a rider to allocate
this missing revenue to remaining classes.

A MR. OSLER: Okay. I'll try and keep
it simple.

The revenue-requirement
issue and the rate issue, in the sense that
we're talking about, are quite separate
boxes.

Q Okay.
A MR. OSLER: One tells us how much we are allowed to collect and need to collect from customers in order to make the company whole, or YEC whole, and the other one is the authorized method of doing it through rates.

To keep it simple, 1997, the Board had approved, assuming the Faro mine was there, a revenue requirement and a bunch of rates without any of these riders. Faro mine closed. The company lost a lot of revenue. It had some costs reduced as well. The net difference was in the order of magnitude, and I'm speaking entirely from fading memory, 5, 6, $7 million out of 13 or 12 or something total revenue. So there was a net amount we still had to pick up from other customers because of the fixed cost to the system.

We were all alone, YEC, before the Board. YECL wasn't there anymore. The Board had let them off. And, essentially, Madam Chair, we had to pick up that amount of money. And the simplest way to do it was simply to have a Rider J that applied to all retail customers in the Yukon, there was the amount of percentage that would recover that
shortfall, was about 15 percent, let's say.
That's all that's happened today. It's just a
method of collecting money from all the retail
customers in Yukon by a percentage.

And it's adjusted in --
it can be adjusted from time to time over this
history as the Board authorizes adjustments in
how much should be collected. It just sort of
moves up and down.

This new rider that YECL
is bringing in is a similar one. Rider R
that's there right now and the new ones they
are talking about are just simple methods of
across the board, all customers, both
companies, all rate blocks, all charges,
customer charges, demand charges, first-rate
block, second-rate block, everything gets
applied this universal number. It's a very
crude method of collecting money compared to
redesigning rates.

But the redesigning
rates, as we have just been talking about, is a
different process from collecting -- from
determining how much you should collect.

Q And I think, just for the reference, I think in
UCG-5 (c) you explained, I guess, the complexities of trying to incorporate Rider J into base rates?

A MR. OSLER: Oh, yes. I can remember that.

Q I am going to leave that now.

Now, and also through interrogatories, you have confirmed that -- and I'm just going to reiterate from my understanding, secondary energy users are charged Rider J, correct?

A MR. OSLER: Right. And the reason for that is that they have a very specific rate. It's based on value. Certain percentage of their alternative fuel cost. It has got nothing to do with cost of service; got nothing to do with revenue requirement or our cost. It is just a method of taking some surplus energy and collecting some money to keep rates down for everybody else.

Q And industrial customers are exempt specifically because of the OIC?

A MR. OSLER: Yes, the OIC 2007-94 relating to the rates to be charged to them.

Q Okay, thank you.
A  MR. OSLER:  Well, Mr. Buonaguro, just
there was a fuel element in the rate that is
charged to the industrial customers up to
November 2006, and there is an adjustment
mechanism for adjusting what they are charged
based on fuel price changes. So the concept
was that that particular element does fluctuate
in their charges, but all the rest of it was
locked down by the order in council.

Q  Okay. Thank you for that clarification.

   My clock says 1:30 p.m. I think that's central.

THE CHAIR:  We are coming up to the
time that I think we would take a 15-minute
break, if that is an appropriate time in your
questioning.

MR. BUONAGURO:  That would be great,
thank you.

THE CHAIR:  In that case we will take
a 15-minute break.

   (BRIEF ADJOURNMENT)

THE CHAIR:  Please be seated.

   Would you like to proceed, Mr. Buonaguro?

MR. BUONAGURO:  Thank you.
Q MR. BUONAGURO: I have a couple of questions on Rider F, and I guess the best place to be looking at while we are at the questions is in the application at page 321, I believe, at Section 3.6 has a description of the rider.

My understanding, simply put, is that in your rates, you have a forecast fuel price and a forecast fuel consumption, and that this rider tracks deviations from that; is that correct?

A MR. MOLLARD: Just price; not consumption.

Q Okay. So does that mean that when you calculate the rider to be applied in order to capture the variation in price, you are only capturing the variation in price as it relates to the amount of fuel you forecast over the test period, to consume?

A MR. BOWMAN: Perhaps, Mr. Buonaguro, just to help people out and make sure we're all on the same page, Rider F is an account that Mr. Osler referred to earlier is the account that effectively is a pretty typical type of fuel stabilization mechanism. Most utilities
that use a lot of fuel would have something of this sort.

The account effectively simply calculates off of the price. So when Yukon Energy had its last rate application, 2005, there was a set of fuel prices approved for 2005 for each community, and they're unique by community. My recollection is 56 cents for Whitehorse. I can look up the exact number if you want. There is a price for Faro and for Mayo and for Dawson.

From that time forward, 2005 forward, whenever Yukon Energy consumes fuel for operating purposes, fuel that goes through operating maintenance, the fuel is booked at that standard price.

Any variation in that price -- in the price, up or down, in terms of what Yukon Energy's purchasing fuel for or consuming fuel flows through the account. So if a litre of fuel is used out of the tank that was bought with an average price of 66 cents and the amount in rates would be 56 cents, Yukon Energy would book 56 and it would charge 10 cents to the Rider F account, what's
actually called the "deferred fuel price account."

Once that account, which has the 10 cents charged to it, and then all of the other adjustments both ways, reaches a certain trigger or balance or forecast between Yukon Energy and Yukon Electrical who each have these accounts and they manage them effectively in a coordinated way, a rider or a refund will be put in place with customers to deal with the balance in the account.

So the rider side is different than how the charges arise -- give rise to the balances. But I hope that's helpful to people in the room.

Q Well, I think so.

The problem I'm having in, I guess, understanding it, and maybe it's a small point, but I understand it tracks the variation in price, but price by itself is meaningless unless you have a volume and the year that you are applying it to, so a volume of diesel fuel consumed.

And maybe I'm misunderstanding, but I assume that if you are
fixing a price in your rates; for example, you
are proposing a new price for this rate
proceeding to be embedded in rates, correct?
A MR. BOWMAN: Correct.
A MR. OSLER: Yes.
Q But that price is to go along, I would assume,
and maybe I'm horribly wrong, with a certain
volume to create an amount that's simply
recovering rates.
A MR. BOWMAN: Yes. When you're
developing a revenue requirement, you need a
total number of dollars. So in this
application there is a price for -- forecast
price for Whitehorse for 2009 that would be $1
and 14.9 cents per litre for a given number of
litres forecast.

When actuals arise, the
way forecasts work, the price won't be right
and the volume won't be right. They never are.
That's the way forecasts work. So if the
price, instead of a $1.15 went to .85 cents, so
you have a 30-cent gap, and if the litres,
instead of whatever number is in here, 300,000,
became 500,000, Yukon Energy would be crediting
back the account 30 cents for all 500,000 litre
consumed, every litre consumed, for operating
reasons.

Q Thank you. So that really helps, because the
stress has always been on the price, it seemed,
in the way it's described. But, in fact, you
are actually -- that account also accounts for
variations in volume.

A MR. BOWMAN: Well, no. I don't agree.

Q Okay.

A MR. BOWMAN: I want to --

Q I misunderstood what you just told me.

A MR. BOWMAN: Well -- the account
doesn't deal with variations in volume to the
extent that those variations in volume reflect
a change in cost to Yukon Energy at the
GRA-approved price. It deals with all units
consumed, so it deals with variations in volume
at the variation in price. And these
conversations can get hard to follow if we're
not careful.

But the -- at the end of
the day, Yukon Energy, as we have covered
before, is at risk for its load forecast and
how it supplies its load forecast. That's a
pretty typical standard in dealing with
utilities. So if there is an outage and you have to burn fuel, Yukon Energy pays for burning that fuel. If loads come -- it gets cold, so there's peaking diesel, Yukon Energy pays for that diesel. If loads are higher than forecast or lower than forecast, Yukon Energy absorbs the change in revenue and the change in cost to supply that.

At the same time, one thing that Yukon Energy does not take the risk for, similar to almost any utility that is in a similar position, is for changes in price that it can control. So this account is designed solely to deal with the risks related to changes in price. And in that regard, every litre of fuel that Yukon Energy books is at the GRA-approved price. It's at risk for changes in consumption, changes in volume at the GRA-approved price.

If there's costs related to changes in the price, it goes through the Rider F account. That's not something that the utilities are at risk for.

Q Okay. So that's -- I understood that differently than what you had said just prior
to that, so I am going to try an example again
to see.

So in 2009, for example,

what's the forecast fuel price that you're
using for the 2009 test year?

A MR. BOWMAN: For Whitehorse is $1 and
14.9 cents.

Q And what's the forecast volume of diesel
consumption?

A MR. BOWMAN: Well, the forecast volume
for the entire company is 451,300 litres. And
that would be in CW-17.

Q Okay. It's just an example, so if -- it
doesn't need to be precise.

A MR. MOLLARD: Yeah.

Q So you have a forecast price, you have a
forecast volume. If the price doubles, the
account will capture that?

A MR. BOWMAN: If the price doubles, the
account will capture that for every litre
consumed, correct.

Q If the volume is cut in half but the price
remains the same, the contract's nothing?

A MR. BOWMAN: The contract's nothing.
That is a volume-related variance, so that's a
load-forecast related variance, which
Yukon Energy is at risk for. Whether that
volume of litres goes in half or doubles.

Q Okay. That's the clarification I was looking
for. Okay.

So if we can move on. I
have, I guess, something -- it's a related
question about the DCF, which we spoke of
briefly earlier, the diesel contingency fund,
which is on described on the same, page 3-21.
And you mentioned -- actually, in your earlier
description, you mentioned triggers, and that's
precisely what I wanted to confirm, because I
don't think -- it's not in here.

My understanding is that
that fund is supposed to protect against
variations in water flow, simply put, in the
first instance.

A MR. BOWMAN: Correct. Correct.
It's -- yes. It's called the diesel
contingency fund because it protects against
changes in the amounts the utility has to pay
for diesel as a result of water-flow
variations. The name sometimes causes
confusions; it's a water-related fund not a
fuel-related fund.

Q So if water flow remains as forecast but load
doubles, for example, this fund isn't
triggered?

A MR. BOWMAN: If water flow results in
hydrogeneration being equal to the long-term
average, which is the numbers that the DCF
works off of.

So if you still get as
much water as a long-term average would say you
should get but the load doubles, this fund is
not triggered.

Q Right.

And, similarly, if your
production is cut in half because of a
technical failure in a turbine, that has
nothing to do with this fund?

A MR. OSLER: We'll have to be careful.
It deals with generation, hydrogeneration being
able to produce based on assumed long-term
water. And certainly if there was a
transmission failure that led to a problem that
would not trigger the fund, I think we'd need
to check that in history there weren't -- how
do we deal with some problems with generator
units not being able to perform. You know, there may have been some history there.

But this fund is only relevant when there is diesel in the margin, the way I was talking to Mr. Keough yesterday. So back in the '90's when diesel was being used in the Whitehorse-Aishihik-Faro system. So you were running diesel, and the water flow -- you know, secondly, it's not based on a forecast. We changed all that in the early '90s. It is just based on the long-term average, so that we are not getting into the game of trying to forecast water for each GRA or something.

This is the long-term average. If we're above it or below it, and you had diesel in the margin, you would have to run more diesel or less diesel, if the water flows better than long-term average, or more diesel if the water flow was less. And this fund picked up the difference so that people weren't having GRA revenue requirements bouncing up and down depending on water flows. That's the essence of the point.

In the history of dealing with it, I just don't remember -- I don't know
how we'd find out real fast, but whether or not there were some examples when we had a problem with the, say, Whitehorse Number 4 or something operating because of a technical malfunction, whether that was used to be recover from the fund or whether it wasn't. That's the only query that I have.

Q So from what you are telling me, you are saying A) historically, it may have been used in that situation. But as I understand, I think it's right in the description, this is a fund that was created subject to -- or pursuant to a negotiated settlement?

A MR. OSLER: Yes.

Q And presumably the settlement contains the terms under which the fund was supposed to be used?

A MR. OSLER: It's a short document and, you know, things evolve, so I don't think this -- it's filed with the Board and was approved by the Board in the '96/97 GRA, so it's a matter of record what the settlement is. And it's not that long a document that covered a lot of different topics. This is just one.

Q Is it filed in this proceeding?
MR. OSLER: No. It's filed in -- no.
I would expect it's attached to an order that approved it.

MR. BOWMAN: I will just add on, the negotiated settlement from the '96/97 GRA is what Mr. Osler was referring to that dealt with establishing the DCF out of the earlier low-water reserve fund.

In implementing that order, Yukon Energy ran the fund for three years, '96, '97, '98, and came back to the Board and got an order confirming how it had used the fund. And it's an order from 1999 dating, if I recall correctly, and there's a filing related to that that basically describes the fund and how it was implemented, and that was confirmed by the Board.

So, if anything, the operating rules took a bit of time to get confirm in the right way. But it is a way they are now applied.

But every year the additions and deletions to the fund, which have basically been only interest for the last few years, are filed with the Board.
A MR. OSLER: We -- okay.

Q Okay. So maybe if I could ask for a copy of the original settlement and then the second order you are talking about, which confirmed how it was used, between the time of the settlement and that order. I wasn't following all the dates, but I think you know what happen I'm talking about.

A MR. OSLER: We can give you the Board order and the -- and the settlement that the Board approved back in '96 and the one that Mr. Bowman was referring to later on where the Board -- we'll give you that order that --

Q Thank you.

A MR. OSLER: And whatever is related to it that's useful.

Q Okay. Thank you.

Now, you did mention, you said this account is only -- maybe I'm mischaracterizing what you said, but I thought you said that this is only an issue when diesel's on the margin. But I think you agree that when -- the second point at page 3-22 with respect to the fund says (quoted as read):

"When diesel is not in the margin, the
account can, in certain circumstances, be used to pay for the cost of generation using diesel, i.e., in the case of drought."

A MR. OSLER: Well, we're using the language "on the margin" is being used here as base-load diesel running all year round, and it's just allowing for the possibility that because of low water flows, there may be certain months that diesel had to run. And if that could be established, that it was due to the low water and not due to something else, there would be a basis for charging the fund.

Even when the Faro mine closed, after it closed, the fund was charged, if I'm not mistaken, in the subsequent spring, because water flows were very low. So it was -- it was even without a high load, if the water gets low enough, there could be certain months when the water flow, being low, is what's causing the diesels to run.

Q Okay. Thank you.

I'm going to look at UCG-1, UCG-1 (d), which I think is a quick question. You are asking -- we asked (quoted):
"Please provide details of service reliability criteria that YEC uses as a policy guideline."

And the answer, I think, quite simply was (quoted):

"YEC does not use service reliability criteria as a policy guideline."

Could you describe that more fully. Because I would have expected that you would have some sort of reliability targets or some such that you strive towards, something like that, at a matter of policy, and this suggest that you don't.

A MR. BOWMAN: I think, Mr. Buonaguro, we might need you to repeat the question. I think the 1 (d), which is about the criteria is referenced as a policy guideline, and I think the essence of the response is focusing on there is no policy along these lines.

But I think your question may not have been about that, so perhaps we could --

Q Sorry.

A MR. BOWMAN: -- benefit from a repeat of the question.
Q So what you just said suggests to me that you
do have service reliability criteria that you
use.
A MR. BOWMAN: Well, all I said is --
Q Whether it's uses as a policy guideline or not,
we can forget that part of the question first.
Does YEC have any kind of service reliability
criteria that it uses in any capacity?
A MR. MORRISON: We are having a little
internal debate. We are not exactly sure what
you are referring to when you mean reliability
standard. So I guess that would help if you
could help us with that a little bit.
Q Well, how do you measure your actual
reliability in a particular year and how do you
determine what reliability standard you want to
achieve, and then therefore how does that drive
your investment, presumably, or your spending
on reliability?
A MR. MOLLARD: So it actually is part of
the KPI documents that we're going to provide
to you. There will be reliability data in
there, the standard Canadian SAIDI, SAIFI, and
CAIDI, don't test me what those acronyms are.
Q I have heard of them. I'm not sure what the
acronyms mean either sometimes.

All right. Thank you.

That will be very helpful.

I haven't seen those documents yet, but presumably the reports don't just set out the criteria but talk about how you use them and what you intend to use them for, is it?

A MR. MORRISON: Well with, again, Madam Chair, I'm not exactly sure of the question. But what the reports outline is what our reliability experience is and compares it to other parts of the country, and there are discussions around that, and it also explains what the standards mean and how they're measured.

Q Okay. I guess I'll see when I read it. Thank you.

Now, I would like to ask you some questions about the proposed runoff rates for residential customers, which you went through, I think, a bit yesterday already, so I'd only have some what I call "follow-up" questions. And I think a useful place to be looking at would be the application, 4-10, page
4-10 and 4-11, I think.

And this is where you start to describe the runoff rates and the requirement under the OIC and so on.

And over at page 4-11, at the top, you talk about trying to provide -- and I'm paraphrasing, trying to provide a strong economic disincentive to customers from using electricity for space heating at that time. And the impression I get from the evidence is that the primary goal in -- or the primary behaviour that hopefully the runoff rate is supposed to incent is to refrain from space heating for using electricity.

A MR. OSLER: I think the impression that the filing gave was that -- I don't dispute that, but in retrospect, it's not a good impression in the sense of the full purpose of the runoff rate.

First of all, the runoff rate applies to customers in general service as well as residential, and the concept, as buried in Rate 39, even for industrial.

So the whole idea of having an efficient price signal on the runoff
rate has got a lot to do with efficient price signals for all customers and not just to do with electric heating. So I think in that respect the application focusing on electric heating wasn't helpful to get people's minds around the problem.

It was a useful example, given that we were focused on the residential runout rate, as it changed for this application and was meant to be only nothing more than that, as an example that people could relate to it. But I think it, in some respects, has not helped all the parties come to grips with what's really at stake here.

Q So I understand your point about it being a concept across rate classes, but for the residential rate class, the classes that we're talking about, the -- I think it's fair to say, or at least the assumption appears to be in the evidence, that what puts people into the runoff rate block in terms of energy use, i.e., using more than a thousand per month on average is space heating, largely?

A MR. OSLER: Well, it may be a major factor for the overall numbers, but there are a
lot of other equipments and electrical uses that can push up electrical use per customer in the residential sector that don't have to be just electric heating. So the concept of an appropriate efficiency price signal would apply to all of those uses, not just electric heating.

Q I want to take you to a table, Table 4.11 in the application. This table breaks down your calculation of the bill impacts per consumption level for residential nongovernment, use this as an example.

A MR. OSLER: Yes.

Q And, presumably, you are looking at this, people who fall under the thousand kilowatt hours per month average and below are getting -- or receiving a rate decrease as a result of the proposal?

A MR. OSLER: Yeah. If you look at the table, a couple of points. The table shows, down under "Cumulative percentage of customers," down below all the table itself; you see where I'm looking?

Q Yes.

A MR. OSLER: So it shows you that at
750 kilowatt hours a month, you are talking about, you know, 56 percent of the customers over the year in the last year of record. So the average is not a thousand; it is somewhere down in the lower level, the average use per customer. It's not a thousand kilowatt hours, it's closer to 700.

Q: Sorry. I think we are at cross purposes in what I was trying to say.

If I look at that have column, "Monthly Consump. (kW.h) 1000," that is a customer who averages exactly a thousand kilowatt hours should have those bill impacts, according to your calculation?

A: MR. OSLER: Yes, yeah, yes. If they exactly use that level, that's what the numbers should be.

Q: What you are saying at the bottom here is that approximately 70 percent of the customers are in the 800 to 1,000 --

A: MR. OSLER: Right.

Cumulative.

Q: Sorry. Seventy percent of the customers are below a thousand?

A: MR. OSLER: Yes, or up to a thousand,
yeah.

Q Right. And I can tell that the people that are in the 800 to 1,000 category are actually 70.1 percent minus 56.4 percent?

A MR. OSLER: Yes. And the final part of what you originally asked was, looking at this table, where does the proposal lead to a customer getting -- up to what level on this table does a customer get savings on a monthly basis from the proposal in the application. And -- if I heard you correctly.

Q Well, I was just pointing out that, for example, 1,000 -- if you hit 1,000 right on, you are saying someone in the high -- in the first zone will get a decrease of $22.26?

A MR. OSLER: Yeah.

Q I just want to make sure I was reading that correctly.

A MR. OSLER: And these numbers are all based on the bill that existed at that time.

Q Right.

A MR. OSLER: Because you can see it all on the bottom and what the rates were assumed. This is all changed now because of the Rider F, you know, et cetera.
Q I am just using it as an example of how you have done the calculation; that's fine.
A MR. OSLER: Good.
Q Now, when you say monthly consumption 1,000, is the assumption that in each and every month of the year the consumption is 1,000?
A MR. OSLER: If you were applying this to an annual number, you would have to take this and multiply it by 12. This is the monthly bill.
Q Right.
A MR. OSLER: If you said what is the effect on this on the customer for the year and you multiplied it by 12, you would be assuming that customer had 1,000 kilowatt hours each month for 12 months.
Q Which is getting to my point, which the assumption there would be that their consumption is flat?
A MR. OSLER: Yes.
Q And now we have already talked about the fact that for residential customers, one of the major factors affecting their movement into the runoff rate above a thousand is probably space heating?
A MR. OSLER: It would certainly be one factor, yes.

Q And you would agree with me that, well, space heating, almost by definition, is a weather-sensitive load?

A MR. OSLER: Yes.

Q Which means that the consumption for somebody who's using space heating over the course of the year isn't flat; it's depending on the weather?

A MR. OSLER: Correct, and there are probably other elements that deal with temperature, light availability, and everything else that would lead to variability, even if somebody didn't have space heating.

Q Okay. That means if I'm trying to look at what the annual impact of the changes are or the -- on a particular customer who has space heating, for example, I can't just take -- for example, if I look at -- let's assume, for the sake of example, and I don't know this to be accurate or not, but let's assume we are looking at someone 1,250 kilowatt hours per month average, and let's say that person is space heating. This suggests that over the course of a year,
250 kilowatt hours will occur in the second rate block, in the runoff block?

A MR. OSLER: The table itself just
tells you a monthly bill. It doesn't purport
to extend it to an annual bill, right?

Q Okay.

A MR. OSLER: So the table is there so
you can look at it and say, If you want to
assume that somebody's flat all year round, you
can calculate an annual number. If you want to
assume somebody's got half of the year where
they are at 2,000 kilowatt hours a month on
average versus the other half of the year they
are only -- you can do the calculations. It's
that type of use.

Q Okay. I think that's helpful to me.

So if I want to -- if I'm
a customer and I am looking at this to try to
figure out what my rate impact is going to be
as a result of your proposed changes, I
actually have to look at my winter peaking
months, I guess, would be January, December, so
see what my consumption is in that month to
determine the maximum impact on a particular
bill I'm going to get; I can't just look at my
yearly consumption?

A MR. OSLER: Right. You are right.

Q Okay.

A MR. OSLER: So these annual averages, so if you looked at the percentage of customers in each group, that's an annual average. So if we were looking at the picture for the winter months or the -- there would be a higher percentage of customers in the higher levels than you see here. And if you looked at it during the summer months, it would be the other way around. There just is a lot of different data, depending what you're trying to do.

This type of a table has been used in previous GRAs to provide customers and the Board and intervenors with an understanding of how does their monthly bill change, and then given the range of different consumption levels that might be relevant to different people, they can see how it affects them. And it's also to help the Board and intervenors understand the extent to which the rate changes are universal across all these levels or whether they are focused on certain levels of consumption.
Q Now, forgive my ignorance, but when you say continual percentage of customers, I'm assuming that you are talking about YEC residential customers, as opposed to Yukon-wide, or I'm wrong?

A MR. OSLER: No. The point was made that these are residential nongovernment customers in Yukon, YEC and YECL. They all pay this rate, and that's what this percentage is, and the same with general service, if it is in the general service.

Q Thank you for that clarification.

A MR. OSLER: Well, yeah. I mean, the -- it's effectively, on an average basis, 84 percent of the customers are consuming between 1,000 -- consuming less than 1,300 kilowatt hours a month. This proposal is saying that, you know, 84 percent of Yukon residential nongovernment customers would end up with no higher rate or a rate decrease under the proposal. That's what it's telling you.

Q I'm afraid I'm a little confused now, because it strikes me that, particularly when you're talking about the heat-sensitive load, i.e., the people using electric space heating, that
the percentage of people that fall into any
particular category would depend on which month
you are looking at, and I'm trying to figure
out -- I can't tell that from here. This is
looking at the average month, right?

A MR. OSLER: This is looking at a
month when somebody is consuming that level of
consumption and what their bill would be before
and after the proposal.

Q Right. But the --

A MR. OSLER: The cumulative percentage
of customers is looking at the average
annual -- looking at all the customer bills
over the 12 months and saying what percentage
of those bills involve customers that didn't
consume more than, say, a thousand kilowatt
hours in a month over the whole year.

Q So, for example, if I look at "Monthly Consump.
(kW.h) 2000" --

A MR. OSLER: Yes.

Q -- and it says 96.1 percent of customers --

A MR. OSLER: Yes.

Q -- that means that only 3.9 percent of the
total annual bills were above 2,000, for
example?
A MR. OSLER: Total annual bills.

It means that 3.9 percent of all the bills issued to nongovernment residential customers were less than -- were over 2,000 kilowatt hours a month.

Q In the year?
A MR. OSLER: In the year. This was the year before the test year.

Q Okay. So you've got monthly consumption at the top, and then in terms of where people fall, it's based on the average -- based on the numbers for the annual?
A MR. OSLER: Right, yeah.

Q Okay. Thank you.
A MR. OSLER: If you take all of the bills that are issued in a year, each customer, if they're around the whole year and they're not temporary, some part of the year, they have 12 bills a year. So all those bills, it's telling you that 3.9 percent of them were over 2,000 kilowatt hours.

Q Okay.
A MR. OSLER: And it's telling you that all the bills issued in a year, if it's the same percentage distribution in the future test
years as it was in the last year before, of all
the bills issued in a year, 84 percent of them
would have a rate decrease or no change in
rates under the proposal. That's what it's
telling you.

Q Okay. Thank you.

I'm turning to UCG

Number 30. And we asked a number of questions.
And if you could skip down to the answer to
(b), (c), and (d), and (i), (j), and (k) --
sorry, (f), (g), and (h). Those questions had
to do with specifying the cost on one system
versus the other, the WAF system versus the MD
system.

And the general answer to
those six questions was -- and I'll just get
the exact wording here -- (quoted):

"Yukon Energy cannot provide this
information as a substantial component
of YEC's costs are not functionalized
and separated by system."

Do you see that?

A MR. BOWMAN: Yes.

Q So basically what I took that to mean is, when
you look at the costs of the system, you don't
distinguish between, for the most part, WAF and
the MD systems; you are not separating them
that way?

A  MR. BOWMAN:  No, that's not what it
says.

Q  Perhaps you can explain it. This is a
cost-allocation question, is it?

A  MR. BOWMAN:  This is exactly a
cost-allocation question of the way that one
would go through analyzing costs by function in
preparing a cost-of-service study, the
generation, transmission, and distribution
broken out effectively of sort of fully loaded,
if you like, so that administration costs are
built into there and allocated to the function
that is needed.

And in this case it asks
for them broken out by system. In Yukon --
even if we had done this in -- you know, had a
cost-of-service study up to date and handy and
ready to go, first of all, it probably would
not address all of the years there. It would
be to deal with a test year. And, second, it
would never break it out by system because the
cost-of-service study is done on a unified
basis for Yukon.

But the form of
functionalizing average cost per kilowatt hour
generation would have to take into account not
just an O&M budget for generation but a capital
amount for generation, the debt that gets
allocated to that system, the administration
costs that get allocated to that system, and
all those other functions, which is exactly the
work of the cost-of-service study that has not
been done.

Q So can I take it from that answer that once you
have completed the cost-of-service study, as
contemplated, for example, in your letter to
YECL, May 1st, that this type of analysis will
be available, this part of the product?

A MR. BOWMAN: In respect of the
questions that are asked here, the average cost
per kilowatt hour of generation, average cost
per kilowatt hour of generation, average cost
per kilowatt hour of transmission, average cost
per kilowatt hour of distribution would be able
to be derived from the cost-of-service study.
It probably wouldn't be oriented that way for
some of the things that you and I were talked
about earlier. Transmission costs are not usually thought about as a kilowatt hour type of cost. They are thought about as a peak type of cost, let's say, so kilowatt. But the data would be available to have a fully loaded functionalized cost. So in regards to the functions, yes.

In regards to doing it by system, no. And that's because a cost-of-service study for Yukon, in the way that rates are set, is done for the Yukon as a whole. It's not meant to set rates on each system on their own. In regards for having one for 2005, '06, '07, '08, and '09, no, it would be done for a year where you have a consistent set of costs between the two utilities, presumably a test year for each utility.

A MR. OSLER: Let's be very specific. We would propose it would be done for 2009, when there has been an approved revenue requirement for each utility for that full test year. Secondly, it would be a consolidated number for the two companies. It would not be separated out. And, thirdly, it wouldn't be separated out for system.
But it would be itemized as to generation, the cost that went into the
generation number, the cost that went into the
transmission number, and the cost that went
into the distribution number. There would be
tables that would show where the heck did all
these numbers come from. But you couldn't
trace them back even to each company unless you
buried yourself in the bowels of the initial
melding of the numbers.

Q So I'm just going to test my understanding a
little bit. What I understand you to be saying
is that the reason why, for example, you
couldn't -- you wouldn't be able to separate
them out into system, so WAF versus MD systems,
is because the exercise that you will be going
through in the cost-of-service study would be
to take the costs and allocate them to customer
classes and not necessarily to take -- not
necessary to take your, for example, your
administration costs and allocate them to the
systems?

Like, you have direct
costs, direct identifiable costs, that are
directly attributable to the WAF system and the
MD. And to that level you have separate costs for each of the systems, but you haven't fully loaded -- you don't calculate fully loaded costs for those systems. Instead you fully load the costs to the customer classes?

A MR. OSLER: Yes. And the reasoning is that you can theoretically do this at all sorts of levels of data if you have the time and the money. That's not -- the point isn't could you do it. It isn't done because you are not trying to waste money, essentially. And the point of the cost of service is to inform parties of how consolidated costs of the two utilities affect customer -- if we looked at them by customer class, where the customers paying for those costs, or are they paying a lot less for those costs or a lot more, and perhaps to give advice on individual charges, such as demand charge versus a customer charge, although historically the charges have not tended to track what cost of service shows.

So for that reason to do what -- the job that's been assigned to people to do and to do it as cost effectively as possible, it focuses on what Mr. Bowman's
describing, the consolidated systems and the consolidation of the two companies, because that's how the rates have to be set.

Q **I think I understand.**

A MR. OSLER: Then somebody will come in inevitably and ask us to do it at some other, and if the Board so directs, we would do it. But we wouldn't do it automatically because it's costly to get more detail.

Q **So, for example, if the Board were convinced that it was important to understand how one system is more or less expensive than the other on a fully allocated basis, that's when you would undertake that kind of study?**

A MR. OSLER: Yes. And if you look back on the sort of mid-1992 or '93 when there was a generic cost-of-service review, some of those questions were asked, and a lot of different tables were produced, but we didn't keep doing it for each GRA thereafter.

So if there was a major hearing process to sort of get everybody comfortable, you might have a lot more things looked at than if you were just doing a regular ongoing GRA.
Q Thank you. I would like to take you to UCG Number 38(a). And you provide a table in response and the only part of it I'm actually interested in at the moment is the qualifier at the bottom. It says (quoted): "There are no profit sharing or incentive plans in the GRA revenue requirement."

Do you see that?

A MR. BOWMAN: Yes.

Q Does that mean -- does that mean that these numbers have been "scrubbed clean" of profit sharing or incentive plans but they do exist?

A MR. MORRISON: No.

Q Or simply --

A MR. MORRISON: They don't.

Q -- YEC doesn't have those things, YEC doesn't have profit sharing or incentive plans?

A MR. MORRISON: No. No, we don't.

Q Okay. Thank you. That was the clarification I was looking for.

At UCG Number 47, we asked about depreciation rate study, and the answer is that, to paraphrase Yukon Energy
currently has no plans to undertake a further
depreciation study at this time, and you refer
to the fact that the current depreciation rates
were approved -- established and approved by --
in reference to the 2003 Garrett-Fleming study.
Do you see that answer?
A MR. MORRISON: Yes.
Q Now, my understanding is that that same report
suggested the completion of a full depreciation
review should be undertaken every three to
five years. Does that sound familiar?
A MR. BOWMAN: I notice that you
reference it in the question from an
interrogatory from McMahon-YEC-16 in the 2005
application. So I have not reread the report
to see if it's indeed in the report or whether
it's just in that interrogatory response. But
people who do depreciation studies recommend
you do depreciation studies quite often.
Q Right. So that depreciation study was done in
2003 which would put it at the five-year --
this is five years or more than when that
depreciation study was done the last time; is
that right?
A MR. OSLER: Well, it was done 2003 for a 2005 hearing. So the time period since
the 2005 hearing isn't that long. I mean they always do it for a period earlier than the
period of the hearing, because they have to use the numbers. They have to have actual numbers.

Q So it may be you may be at the three-year, you may be at the five-year range depending on when the start date is?
A MR. OSLER: Yeah.

Q So when would Yukon Energy's plans be to update its depreciation study?
A MR. MOLLARD: We have no plans at the current time to update those.

Q UCG Number 72(b). We asked for analysis that YEC had made to verify that the miscellaneous charges within the electric service regulations are still appropriate given associated costs. And the answer was (quoted):
"This type of analysis is not available and cannot be provided."
When was the last time that type of analysis was available and provided to the Board in support of what's in the electric service regulations?
A MR. OSLER: The miscellaneous charges you are talking about would be various items in here. The last time this was reviewed at best would be the '96-'97 GRA. I mean in the 2005 GRA, Yukon Energy addressed some specific items in here and got some changes approved for them, but they weren't the miscellaneous charges. It would be a matter that would probably -- would definitely require the involvement of the two utilities. And if the planning was going forward, it would be next addressed in the context of this upcoming Phase II review.

A MR. BOWMAN: I want to add, Mr. Buonaguro, in case that wasn't clear. The charges are in the electric service regulations, which as I say, consolidated for the two utilities, it would relate primarily to dealing with customers and customers charges. So they are actually a very small item for Yukon Energy. Most of the charges that occur in Yukon under any of these are related to Yukon Electrical, not Yukon Energy required -- because Yukon Energy deals with very few customers.

Q Okay. I will take that point, thank you.
So this is something that if it's going to be reviewed would be reviewed in connection with Yukon Electrical. So just looking at the B-13 letter, you refer to (quoted):

"...jointly proposed changes to the Electric Service Regulations (Terms and Conditions of Service)...."

Would that come under that heading?

A MR. OSLER: Yes.

Q Thank you.

I think you can tell I'm picking up the last little pieces here. UCG Number 77. At Number (a) it talks about line losses. (Quoted):

"No detailed calculation of line losses has been performed. In general terms, Yukon Energy's transmission level losses on WAF approximates 7%-8%...."

The background data that leads to the conclusion, is that on the record? Obviously that's the result of some sort of analysis.
A MR. BOWMAN: Well, it's the result of operating experience. The data required to calculate loss numbers is included in Table 2.5, and it shows that on a company as a whole it's 8.42 percent, and there's some discussion of losses by system in one of the interrogatories. And I can look that up in a minute. That would include any distribution system losses that Yukon Energy incurs related to the small amount of distribution it owns. At the transmission level, 7 to 8 percent is a number that is routinely used, and it was discussed at some length in the resource plan hearing is my recollection. I think there is even an exhibit filed in regards to it.

But certainly there is an interrogatory in the materials that deals with the losses by system.

Q Okay. Thank you.

Now, can I take you to UCG Number 81(b). And this line of questioning actually applies to a number of questions that follow it. And I think maybe once you see what I'm talking about you will understand. So UCG-81(b) we asked for confirmation (quoted):
"...that the budgets for customer extensions would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual customer extension costs as they are incurred for disposition in a subsequent year."

And the answer for this one was (quoted):

"Not confirmed. The amounts are already capital and consequently depreciated over time."

Do you see that?

A MR. OSLER: Yes.

Q So there was a series of questions after that that a very similar question and answer were given. And it was based on the idea, for example, that -- the question was based on the idea, for example, that (a), if you have a budget for 2008 of 400,000 and you have actual spending of only 84,100, the presumption was, well, if you'd used the actual, one way or another there would be savings to a customer in that example. And the answer was no.
(Quoted):

"The amounts are already capital and consequently depreciated over time."

Could you maybe explain more fully what that answer means? Because I have sort of an idea what you may mean, but I don't want to mischaracterize it.

A MR. OSLER: Could I suggest that we explain first what we do.

Q Okay.

A MR. OSLER: And then see if you have other further questions. So from the gentlemen to my right, you know, how do we actually just explain simply what we do?

A MR. MOLLARD: In any given year we'll have a varying number of customers that will show up on our door requesting service. We don't know what that number is going to be at any given year, but we are required to serve those customers, and it also varies in complexity in terms of somebody might be right next to a line or they might be quite a distance away, so we don't know what that cost is. However we are required to forecast that. That's a cost that we're going to incur. So we
look at our historical spending in that area
and come up with a number to forecast what we
think it will be. Now, those costs are capital
in nature. Generally customer connections are
an asset that has about a 45-year life. So we
will capitalize those costs on any given year,
and it will be added into revenue requirement
at a 45-year rate.

Q When you say they are adding into ratebase at a
45-year rate, the critical question is what
number is put into the ratebase. And I think
what your answer to (b) means is that for 2008,
for example, even though the budget was
400,000, are you telling me that from a
ratebase perspective that doesn't matter
because what actually goes into ratebase is the
184,100 was actually spent?

A MR. BOWMAN: Well, you want to be
careful when you talk about ratebase as opposed
to spending, because these are largely offset
by amounts the customer pays in order to be
connected. So these are very small amounts
when we get down to it. I realize just as a
correction 2008 we list the budget of 400,000
in that IR. That is actually a typo. It
should be 475,000, and you find that in Table 5.2.

The issue is that although Yukon Energy forecast to spend $475,000 on these hooking up customers, it forecast that the customers themselves would hand back 400,000 of that 475. So the total amount that would go into ratebase would be 75,000, because it's offset by customer contributions. That 75,000 that goes into ratebase would then be amortized over the life that Mr. Mollard notes. This asks for the actual spending in 2008, which was 184,000. I can also note that the actual contributions in 2008 were on the order of 130,000. So the amounts that went into ratebase in -- in actual 2008 was closer to 50,000 rather than 75,000. And that amount would be amortized over the 45 years or whatever the number that Mr. Mollard had.

Your question had gone to what if it was done using a deferral account. Well, in effect, because it's capital, it's already deferred. There is no expense of 75,000 or 50,000 in the test years. It's
amortized over that whole life.

Q That's very helpful. So I guess the critical point is whether the budget is twice as much as you spend or half as much as you spend, what actually affects rates is actuals when it gets capitalized or whatever amount gets capitalized after customer contributions as an example.

A MR. BOWMAN: Well, what is in ratebase for 2009 or 2008 is what was forecast, 475,000 to be spent, 400,000 received from the customers, a net of 75. By the time we use the next GRA, those would be trued up for actuals in ratebase the same way that 2005 numbers are here. But it's 475 to be spent offset by 400,000. The remainder is the maximum company investment that we talked about in the --

A MR. OSLER: But in addition if you are going to the bottom line how is it affecting test year 2009, whatever that number is, the net is then amortized over the life we're talking about, and only the first year of that amortization goes into 2009.

Q So just to close it off, then, to the extent that the budget amount is higher than the actual amount in the year, there would be an
increase or an increase in rates relative to that overbudgeting amount. What you are telling me is, A), that is because it's amortized over several years, that amount becomes smaller, and B), it becomes corrected at the next general rate application once the actual and the budget are reconciled?

A MR. BOWMAN: Yes, and it's only the variation in the net that matters. So as Mr. Osler noted, this GRA forecast, a net spending in 2008 of $75,000 amortized over 45 years, that's $1,500 a year plus return on 75,000. But -- so it ends up being a very small amount. Even if spending is under, because you connect less customers, it's still the net that matters. And the net as I said for '08 is still in the order to 60,000 compared to 75,000.

Q And I guess in this particular example you talked about the budget actually being 475 but then there would be an offsetting forecast of customer contributions?

A MR. BOWMAN: Correct.

Q And I am assuming that the offsetting customer contribution forecast is accounted for when you
are putting this forecasted budget into ratebase for the purposes of the -- of rates for the test years and then reconciled a few years later when you do the next GRA?

A MR. BOWMAN: Well, correct. It's at Table 5.1.

Q Okay. Thank you. So I can tell you that 82 --

UCG Questions Number 82(c), you don't have to turn them up right this second, but 82(c), 83(b), 84(c) all had very similar question and answers where you said don't worry about it; it's already capitalized. And I think your explanation would apply equally to all those questions.

A MR. BOWMAN: Well, without turning them up, I can't confirm what each of them was about. It's not any given item in capital. Not all of them have the same offsetting contributions like we talked about --

Q Right. I understand.

A MR. BOWMAN: -- for contributions.

But I issue is -- the question effectively goes to deferral accounts. And rather than taking a whack of a cost in one year, can't you defer it over time to make things more stable? When you
are talking about stuff that's capital, it's not taking a whack of the cost in one year. It's already deferred over its life. So the question -- in that regard the question -- the answer would be the same.

Q Thank you. I think that was the curdle of my clarification I was looking for, thank you.

In UCG-86, 87, 88, and 90 we asked you about actual expenditures for certain projects, and in each of those cases the project spending that was illustrated for 2008 was it appeared to be coming in under budget. I don't know if you want to look at an example first. Turn to Number 86. The spending in 2008 for disaster recovery plan/business continuity plan was forecast to be 150,000 in 2008 and the actual spending, it's at (b), was 73,000; do you see that?

A MR. BOWMAN: Mr. Buonaguro, yes. I have those responses. This same set of questions went from UCG-85 to 88 on a series of projects.

Q Right.

A MR. BOWMAN: Three of them, the '08 spending was below forecast in the GRA. One of
them the '08 spending was above forecast in the GRA, which was a SCADA replacement at UCG-85, and in fact that project was completed ahead of schedule. It was forecast to continue into 2009. It was completed in 2008.

Q The question --
A MR. BOWMAN: That's --

Q The question with respect to the ones that are showing underspending the simple question was are the projects themselves coming in under budget, or is the spending just deferred to 2009? Are they actually coming under budget, or is this just a matter of timing?
A MR. MOLLARD: I believe in the case of those examples that it's a deferral. The spending will still happen. It's just been pushed to later.

Q Okay. Thank you.

So maybe I can -- that is with respect to the projects referenced in Number UCG-86, 87, 88 and 90 are the ones that I think are coming in under budget, and I'll take that subject to your checking if you want to check each of those to make sure that's the case in all four. I don't want you to leave it
out there.

A MR. BOWMAN: We can confirm the first three. UCG-90 we haven't had a chance to look at. But for the first three we can confirm.

Q So do you want to look at 90 right now or do you want to take it as an undertaking? I don't need it right now.

A MR. BOWMAN: Well, I know you have got am plane so perhaps we --

Q No, no. I still have five minutes and less than five minutes of questions.

A MR. MORRISON: Mr. Buonaguro, we would have to get back to you. I can't answer that one right now.

Q That's fine. So is that just with respect to the project at UCG-90?

A MR. MORRISON: Yes.

Q Okay.

MR. BUONAGURO: Thank you. Those are my questions.

THE CHAIR: Thank you for sticking to your self-imposed time lines, and I hope that there will be some people left around for some Board questions later on as well and people don't exit as well.
And we'll take a break for lunch and we will return around 1:30.

(PROCEEDINGS ADJOURNED AT 11:54 A.M.)

(PROCEEDINGS RESUMED AT 1:33 P.M.)

THE CHAIR: Please be seated.

Just before we get started, I just wanted to put everybody on notice that it will be the Board's intent to sit later this evening, until maybe 6, 6:30, and it appears, based on estimations of cross-examination times, that that should complete our hearing. But I will have a better update at the break to see how cross-examination is going.

Mr. Landry it looks like you want to jump to your feet there.

MR. LANDRY: Yes, Madam Chair.

I just have one undertaking to deal with, and that was the undertaking to Mr. Buonaguro regarding the key performance indicator reports. I have given a copy to Ms. Lemke, a hard copy. I would ask that it be marked as the next exhibit. But I did it a little differently. Because it's a little lengthy, we emailed it to everyone,
including the Board. If somebody would like a hard copy, we can do that. But in speaking with others, they have already received it electronically, and the Board would have received it electronically. But Ms. Lemke has a paper copy that can be mark as an exhibit.

THE CHAIR: Do we have a number for that?

B-14, so marked.

**Exhibit Number B-14:**

Key performance indicator report.

MR. LANDRY: That is the only undertaking we have at this point in time. Hopefully before the break we will have more.

THE CHAIR: Thank you Mr. Landry.

Mr. Maissan, are you prepared to proceed?

MR. MAISSAN: Yes, I am ready.

I would like to start with, I guess, filing an exhibit. During the break this morning, I confirmed with the panel that they could access an Excel spreadsheet that they had provided as part of responses to interrogatories. It seemed it was going to be difficult. So what they did for me is make
paper copies of my notes on the subject. So I think for everyone's convenience, if we circulate this as an exhibit, when the time comes, then we can -- then we can just refer to the paper copy rather than dragging up an Excel spreadsheet.

THE CHAIR: So if I understand you correctly, it comes from an answer, an OIC answer?

MR. MAISSAN: Correct.

THE CHAIR: How would you like to mark that, Mr. Maissan, then?

MR. MAISSAN: I think from the exhibit list it would be C4-5.

MR. LANDRY: I'm fine with that, Madam Chair.

THE CHAIR: Maybe we will just mark it C4-5 for reference.

Exhibit Number C4-5:

Paper copy of OIC response.

MR. MAISSAN: The other thing I would like to say at the outset, for my convenience and probably for time saving as well, when I'm referring to interrogatories, I shall refer to the initial acronym and the final number,
instead of spelling out the long in between. So, for example, if I'm referring to Leading Edge-Yukon Energy-1-12, I would just say Leading Edge-12.

THE CHAIR: Thank you.

MR. MAISSAN: And same with the other interrogatories.
we are talking about the same line.

Q YECL-17 is one of these, and Leading Edge-33, and YECL-18. One of those line's numbers is likely referring to the Aishihik-Haines Junction line and the other to the Faro-Ross River line, but just to keep the numbers straight.

A MR. MORRISON: Mr. Maissan, we are going to have to take a look at it and come back to you.

Q Sure. That's not a problem.

And I wondered if there is a number for the new 138-kV line from Carmacks to Pelly Crossing. Is there a line number for the that or will there be?

A MR. MORRISON: I'm sure there is because we number everything, so I'll get you that as well.

Q One final comment, then, is in response to YECL-17, there is a list of substations, both by Number S and a particular number and a description of the substation. Having a list like that for lines and for plant numbers as well, we get into P numbers as well, would be convenient at future proceedings.
Could someone please explain to me what a pothead is and what it does.

A MR. MORRISON: Well, let me give you the nontechnical version of the pot -- well, you know, I guess I was going to -- never mind. I won't go there.

Q Yes. There are --

A MR. MORRISON: Let me give you the nontechnical version of what we refer to as a pothead. It is a connector for cabling.

A MR. MOLLARD: It is an electrical connector for a reactor.

Q Does Yukon Energy carry spare potheads?

A MR. MORRISON: Let me -- let me be careful -- I just want to be really specific about that. Whether -- we may have a few spare potheads because they are an old technology, if you will. And, generally, what we would do is if we had -- if we were changing them out on a -- say, on a maintenance basis, we would change it to a different kind of a connector, not a pothead.

Q Now, you anticipated my last questions, which was, Are these maintained on a regular basis or
on a preventive-maintenance basis, et cetera?

A MR. MORRISON: No. We try and maintain everything on a maintenance basis, but these are similar to -- I feel like I'm explaining something to the expert. I'm -- you know. So the -- you know, what they are is an enclosed metal connector, and so the maintenance piece on it is an infrared scan, and we do them. But if between doing the infrared scan and doing the next one you have a problem -- you can't see inside it, I guess, is my point.

Q Thank you.

These questions of course stem from the pothead failure at Aishihik that caused the outage.

A MR. MOLLARD: Correct.

Q Secondary sales, I understand that the notice period for secondary sales customers that are not SCADA connected is 24 hours; is that correct?

A MR. BOWMAN: Trying not to rely on my memory, it is 24 hours, and it would be the Secondary Sales Rate Schedule 32, which is attached to Tab 4.

Q Thank you.
And the notice period for SCADA-connected customers, of which I understand there are only one at the present time --

A  MR. BOWMAN: It is stated in the same rate schedule of 15 minutes' notice.

Q  Fifteen minutes, right.

Is there any possibility of the SCADA control secondary sales customers being interrupted on an instantaneous basis in a load shedding kind of format during system upsets to try to maintain the rest of the system whole?

A  MR. MORRISON: Are you talking about the ones that are not connected by SCADA?

Q  The ones that are SCADA connected.

A  MR. MORRISON: The ones that are SCADA connected?

Q  Yes.

A  MR. MORRISON: I guess we could interrupt them at any time within that 15-minute period, as long as, let's say, as an example, it was in the middle of the summer and didn't need their heating system and we called them and said, Is it okay if we just turn it
off. Or B) in the winter, the 15 minutes is to
give them time to switch on their alternative
source of heat.

So the capability is
there, but the fairness option is we have to
let them turn on whatever they need to turn
on.

Q Right. So I'm thinking of the situation in
which there is perhaps a failure of a
generating unit. I understand the system as a
whole operates by a load-shedding mechanism and
drops certain areas, say, Riverdale or
Porter Creek or whatever to try to maintain the
rest of the system whole and keep it operating,
minimize the outage numbers in terms of
customers interrupt, and I just wondered if
secondary sales -- SCADA-controlled secondary
sales had some potential to be of assistance in
that?

A MR. MORRISON: I think it's very
difficult to get it closer than that. You
know, you are talking about the hospital, to
start with, which is, you know, pretty
important that we know that they've got their
heat on, and I'd be loathe to even talk about
that just in the fact that what happens if they
don't get their heating system on and we have
got them turned off. So I wouldn't -- I
wouldn't like to go there.

Q Fair enough.

In answer to

Leading Edge-12, Yukon Energy says that
(quoted):

"...there is no reasonable temperature
at which peaking diesel would
be...required on a 24 hour basis."

Am I correctly

interpreting this to mean that during our cold
winter weather, for instance, in December
through January, when the diesels were being
run in the daytime, that it was still possible
to sell secondary sales to a SCADA-controlled
customer?

A MR. MORRISON: I guess maybe a little
clarity around the question, Madam Chair.

When I look at the
question and the answer, I'm not sure that --
I'm just not sure what you are asking me in
relation to this question.

Q Well, I understand that diesel -- when diesel
peaking is required --

A MR. MORRISON: Right.

Q -- it's only required for a certain number of hours a day; it's not required 24 hours a day.

A MR. MORRISON: Right.

Q So the load drops down at night. If, for instance, from midnight until 5 a.m. diesels are not required, you have spare hydro capacity, do you in fact do some secondary sales during that nighttime window?

A MR. MORRISON: Well, it would depend.

And let me say that. First of all, if we -- if we're in a situation where we have secondary sales turned off, we can certainly turn the SCADA customer back on and off.

We don't generally, because it's a manual disconnect and reconnect, we don't do that with all the other customers until we're sure we're out of the woods in terms of the peaking.

So yes, we can with a SCADA customer and yes, we would with a SCADA customer.

Q Thank you.

Could I ask you to turn
to Leading Edge-14, please.

A MR. MORRISON: Sorry, Mr. Maissan, I think Mr. Bowman would like to make a point just in addition to that answer, so if you don't mind.

A MR. BOWMAN: I was just going to say that in the type of situation you are talking about, one would also need to be attentive to what else is happening overnight. The example being, if you are in these very cold temperatures, the people operating the system are doing their best to supply all the load they can during the day with hydro so you run the least amount of diesel. One of the tools available to them is to deal with the storage at Schwatka Lake, which is a very small amount of storage.

But, nonetheless, by drawing that down some amount, you can push through a bit more water during the day in order to help meet those peaks. But you can only do that if at nighttime you are allowed to back off and let Schwatka come back up. So during those cold periods, we would have to be attentive to whether that water that one would
otherwise sell for secondary is really better
used to help refill Schwatka for the next day's
bit of daily peaking.

Q Understood. Yes, I think that's also explained
in another IR.

Leading Edge-14, if you
could turn to that. We were talking here about
the Aishihik storage. And the answer in the
second paragraph, and I should read it for
everyone's benefit (quoted):

"In regards to the test years,
Yukon Energy assessed the situation
where Aishihik started fall 2008 at
full levels, and using forecast loads
(including secondary sales) determined
that even with Aishihik inflows at 50%
of normal during the following 1.5
half year period (to spring 2010)
Aishihik would reach its lower supply
level by that time."

I understand that answer,
but what I'm not sure about is the practical
implications of that. Would that mean that if
there were secondary sales customers available,
you would continue to serve secondary sales
customers during drought period, even if it meant drawing Aishihik Lake down to its lower licence limits; i.e., at what point do secondary customers get cut off out of concern for the water storage at Aishihik?

A MR. BOWMAN: Yes, your question, if I have it right, was, If you were in the drought, would you keep making those secondary sales? And the answer is, It would have to be something that was assessed on an ongoing basis.

What we know in terms of this filing is that we were in -- making the filing in preparing the filing in the middle of 2008. We were looking forward to a future situation once Minto mine connected and the Carmacks-Stewart was up and running, that would bring the WAF system to a load level that hasn't -- in fact, has never really been experienced. The WAF system has traditionally either been Faro mine is on, you are burning 100 gigawatt hours of diesel, you are running diesel whether it is good water or bad water, basically, and so there are no secondary sales at all. Or it has been the situation where
Faro mine is off, there's a hundred gigawatt hours of surplus, so you could make secondary sales basically all the time.

We're moving into a bit of a different world going forward, which is the load is starting to get close to the long-term average amount of hydro, and we haven't really dealt with that before. So that would be sort of a preliminary comment.

In preparing the application in mid-2008 and looking forward, and this was a matter discussed somewhat in relation to the secondary sales forecast provided to the Yukon Electrical before their GRA, people have had to wrestle with the question of what happens to secondary sales.

We know that when we're making secondary sales, there is a revenue source that helps keep other ratepayers' rates down. So people want to try to keep the secondary sales on as much as possible, and of course there is a benefit to secondary sales customers who have made that investment.

At the same time you don't want to be caught in a situation where
you make some secondary sales today, at a price of 5 or 6 cents, and as a result use water that some -- at some later event you realize you could have used to displace diesel at 30 cents. That's a more difficult type of tradeoff.

And what we concluded in going through it is we're not quite at that threshold yet in 2008 needing to be able to deal with that. Looking through this application, looking forward, this application, we assessed whether secondary sales would stay on in a substantial way through 2008 and 2009 for the purposes of setting rates. We concluded that it would. We concluded that even under a very extreme water flow scenario, 50 percent of normal inflows for a sustained year and a half period, we would not today forecast an interruption to secondary sales. So we were confident that we could file the information that's here.

Now, that doesn't mean it doesn't have to be continually assessed. And if you did reach a situation where we had filed in October, and that winter it had been, you know, low in-flows and next spring there was
low in-flows and you got to summer 2009 and
Aishihik was getting low, and you were looking
forward to where the next water was coming
from, that's where Yukon Energy will have to
continually assess and decide, Is it time now
to say we are approaching a situation where we
need to cut off secondary sales for energy
reasons.

And it is a process that
people need to pay attention to. Thankfuly we
are not there. The water is there at Aishihik
right now, so we didn't run into that situation
in any event.

Q Right. So you would not automatically just run
it to the low supply level, correct?

A MR. BOWMAN: No, absolutely not. The
water at Aishihik gets monitored quite
carefully, and this would be a key item on
people's minds as they watch the water coming
down.

Q Thank you.

UCG-29, could you turn to
that, please.

On page 2 of 2 in the
response -- or in that IR, which, under (b),
UCG-29 (b), there is a table of secondary power and for three years, 2005 through 2007, these are what I believe to be actual sales, and 2008 forecast sales; is that correct?

A MR. BOWMAN: Yes, Part (b) of the table is actuals for '05 to '07 and forecasts in '08 and '09.

Q Right.

Now, the question actually asked (quoted):

"Please provide details of the amount of surplus power available..." as opposed to the amount of surplus power sold. Is that information which you would have available? Because that's -- what you could sell and what you actually sold can be quite different.

A MR. BOWMAN: Yes, they can be quite different. But the question, as asked, could not be addressed or presented in a format similar to the answer that it's given. The question with respect to what could be made available if you were trying to make as much secondary power available. And the reason is that
in -- was particularly with respect to Aishihik, we are not dealing with the run of the river plant. We are dealing with a multiyear storage, although -- or at least more than annual storage.

So what power is available in any given month is a function of how much you made available the previous month. You can only use any bit of water once.

So trying to say in May '08 there is this much available, and then go to June '08 you say, How much is available, well, it depends on whether it was used in May '08 or not. So the numbers sort of start to become very hypothetical or scenario based.

And what you really need to do is consider your load levels, what power is being used in any given month, as well as your in-flow levels, which could be anything from very low to very high in order to do that. It becomes a fairly complicated exercise very quickly, and it is a matter that has been talked about in other places here that people have put a lot of time into doing longer term water modelling to be able to figure some of
that stuff out.

It will never get you to the point where you could do a short-term type of number like this, because it depends on if it rains or not, and it depends on if you used it last month. It doesn't lend itself to a presentation of this sort.

Q So can I also assume from the information here, given the relatively low sales in the summertime, that had you had more secondary sales customers, your secondary sales could have been higher?

A MR. BOWMAN: Yes. Absolutely.

A MR. OSLER: Just for the record, UCG-8 (d) did discuss sort of the broader question of how much surplus is there versus long-term average generation, for those that are interested, because the numbers are different, as has been pointed out, from how much we sell.

And, secondly, you would have to get the load up quite a long way before the summer sales are all absorbed, as they were when we had the Anvil mine on -- Faro mine on, so that even when we're looking forward to
base-load diesel situations the next few years, some of the models that we're seeing are showing still some surplus, but it's all in the summertime when there's no customers looking for it, yet.

Q Now, one further question on secondary sales, YECL-2.

On page 3 of 5, in the paragraph underneath the table of long-term average hydro capability, and the short paragraph following that, there is a discussion about how much -- at what load there would no longer be secondary sales available. And if I understand correctly, what's being stated here is that when the overall load reaches 380 gigawatt hours a year, we would be at a point where the hydro is -- and I think this is a situation with the Aishihik third turbine in operation -- we would be in a situation where there would be no surplus hydro available essentially at any time?

The (quoted):

"...380 GW.h is consistent with a long-term average hydro capability of 356..."
which I think is the full utilization.

A MR. BOWMAN: Yeah, no, that's not quite correct.

Q Okay.

A MR. BOWMAN: And this is -- this is a matter that we were -- we're still learning our ways to be able to talk about and explain this, because it's a fairly complicated topic.

What the response is basically saying is that when people looked at the hydro system back in '96 and '97 and the load that was on the hydro system in '96/'97, they said, How much of that load could be served by hydro, and how much should we assume diesel, at long-term average water flows, and they came up with a number of 351.

That requires some complicated modelling, and that's been a number people have used ever since. But how much your hydro system can produce is dependent on how much load you have to put on the hydro system. The more load you have, you start to squeak those last bits of energy out of those other bits of water, and so at lower load levels, your hydro system long-term average number
doesn't look very high. At really high load levels, or if we had an export market or something of that nature, it starts to come up. What this response is saying is, it's at about 380 gigawatt hours of system load that one would calculate, through the model, that the hydro system long-term average generation is about 356, and that includes the Aishihik. That doesn't mean that there's still no surplus or no water that could be used to generate that isn't being used to generate. If you had a load, instead of 380 gigawatt hours, if you had a tie line to British Columbia and you could sell as much power as you possibly could, you would see the generation even a little bit higher than 356. Without that type of load or that tie line, that bit of water that you would have used just south of BC is available for secondary sales. So you could still have some summer evenings, warm summer evenings, where there is still opportunity for some secondary sales, like where Whitehorse is not using every bit of water it could running
through every turbine.

When you get to those levels, you also have to think about things like that's also the opportunity, the time when your people want to do maintenance on the unit and the like. So you are right at the margins or you are right at the edge of the system's capability.

A MR. OSLER: Let me adjust one thing, if I might.

Sitting outside Whitehorse you have got four units, and we all know that we don't sell -- we can't sell all the power that those units could generate during the summertime. As the system load goes up, we manage to sell more and more of that power that is used -- that's there in the summertime.

The secret to this answer is that the 380 gigawatt hours has recently been figured out to be the number for the system load on WAF where this long-term average, 351, is relevant. If the load is higher than that, we can get a bit more out of this existing system. If the load is lower
than that, we get a bit less, in terms of
talking about useful energy that we could use
to serve customers based on long-term average
hydro flows.

Q Right. Okay.

The reason I was asking
is that I recall when the Faro mine was on and
our loads were in, I can't remember, 420,
430 gigawatt hours per year, on paper we
required 90 gigawatt hours a year of diesel
generation, and yet there were still times in
the summer where we had the capability of
surplus sales.

A MR. OSLER: And that's -- at times
people used to say we used diesel all year
round, and other times some people said we had
some power in the summertime; we could never
sell it. But that's the point we are getting
at is that we can't store the water that's used
in Whitehorse, so therefore we use it or we
lose it. And if we lose it, it's because we
don't have a load for it.

The load maintains the
characteristics we have historically and
doesn't suddenly shift. In terms of
seasonality these numbers make sense. It also means that we have got to get more sophisticated in talking about what is the long-term average generation we can get from hydro. The answer is, it's starting to become internally now, it depends on what the load is. As Mr. Bowman says, this is a challenge for communications. So welcome the opportunity to keep trying.

Q Right.

Aishihik. The Aishihik monitoring group that was examining the results of the fisheries studies, have they made a determination yet whether they are accepting the analysis by Yukon Energy's consultant or not in respect of the health of the fishery?

A MR. MORRISON: No, they haven't, Madam Chair.

Q So at this point you don't know whether there is going to be an impact on storage range?

A MR. MORRISON: At this point, that's correct, I do not.

Q All right.

Can you tell me how the costs for these kinds of periodic studies are
recovered?

A MR. MORRISON: I'm going to -- you want to --

A MR. MOLLARD: They're included in our licencing differed costs.

Q So they are amortized over the licencing period?

A MR. MOLLARD: Over the life of the licence, yes.

Q For a study like this that was done partway through a licence, is it amortized over the remainder of the licence period?

A MR. MOLLARD: That would be correct.

Q Thank you.

I have some questions about hydro systems generation. And, in particular, I would like you to turn to YUB-29. I'm sorry. That should be YUB-31. I apologize.

A MR. MORRISON: You are disappointing Mr. Bowman. He was going to explain the graph for you.

Q I know he was keen to discuss those load duration curves. Right.

On page 2 of 3 there is a
coloured graph called "Hydro Plant Utilization." And on the left-hand axis there is a "% of Maximum." And I just wanted to confirm that the percent of maximum is based on the installed capacity as opposed to the energy available. For instance, I understand that approximately 246 gigawatt hours a year is available at Whitehorse Rapids. Installed capacity is 40 megawatts. So the full utilization of the hydro energy available through that plant would result in the utilization of 70.3 percent, as opposed to a number like 100 percent; am I correct?

YUB-31, page 2 of 3 at the top.

A MR. MORRISON: We're there.

A MR. OSLER: I don't know that there's anybody on the panel who can answer this specific question. It does say "rated capacity," and the implication is that it's based off a simple number like the plant capacity. But unless somebody knows something that -- for sure.

A MR. BOWMAN: We could put it this way: I am almost certain it is megawatts in each of
the numerator and denominator. And if that's not correct, I will come let you know -- I will come back and let us know.

Q Yeah. The point I was getting to, I guess, is it looks, from this graph, as though the Aishihik facility is being underutilized, because the numbers are relatively small, and that's really a factor of the large installed capacity and the limited water flows, i.e., energy available. So when you divide the energy available by megawatt capacity, you get a relatively low percentage utilization factor, but it is in fact a very valuable plant and fully used to the extent possible.

A MR. MORRISON: Thank you for that, Mr. Maissan.

Q Is that not correct?

A MR. MORRISON: That's correct, yes. Just for the record, so that everybody does understand how we operate Aishihik, we generally don't run Aishihik all through the summer. So basically Aishihik stores water all summer, and we operate it in the winter, which is exactly the point Mr. Maissan was getting at, is, so where it
might look like the utilization isn't
100 percent, well, if you had the plant
available 12 months of the year, utilization
would be a lot higher, but it's based on that
six-month operation.

A MR. OSLER: And just to give why we
think we know what the answer is here but we
will come back to you if it isn't, if you took
Aishihik and the system is fully loaded and you
are looking at long-term average, it would be
under 40 percent, I think, would be the
utilization that you'd get.

At the moment it's not
being used the same way because we don't have
the same load. It's not surprising, therefore,
that its utilization is quite low. It has got
nothing to do with the energy available; it's
just to do with the fact that plant was
designed to be run that way.

Q All right. The Mayo hydro plant, could you
tell me what the long-term average energy
available, hydro available is from that plant,
 gigawatt hours per year.

A MR. BOWMAN: The Mayo plant is -- it's
going through some of the same type of work we
were talking about for the WAF plant, that long-term average depends on the load you have on the system.

But in general it is -- if you have it loaded, which is not particularly difficult when you have one plant compared to when you balance two plants, it's up in the upper 30s, but we have been talking in the range of, you know, 35 to 40, but it's depending on the particular load. And that's sort of a long-term average in gigawatt hours.

And the only other comment I'll make is in the case of Mayo, given the installed capacity of the plant, it is not particularly sensitive to water flows. In very, very low in-flow years, it can't produce that much, but in average years or higher-than-average years, it doesn't pick up the extra water. The units are already fully used.

MR. OSLER: Just so the record in the future is clear, that's the Mayo plant that exists today, which is sort of analogous to the Whitehorse situation before we built the fourth unit. The three units of Whitehorse can pretty
well take the river flow, even at its lowest level; add the fourth unit and you are into sensitivity as to all sorts of things.

If we get a Mayo B, we will be doing the same thing at Mayo that happened -- we will be roughly doubling if we keep building the capability of the plant, and it will be more sensitive to water flows.

Q In answer to PWP-18, there is an estimate of short-term incremental costs for hydrogeneration of about .5 cents per kilowatt hour. And I just wanted to understand that this .5 cents, just what goes into that .5 cents. Is that essentially the incremental maintenance cost? Does that include any allocation of operating, labour, system controls centre, insurance, water licence costs, et cetera?

A MR. BOWMAN: I'm not sure we're going to be able to answer that to a level of detail. This is a number that has been used for a long period of time. Determining the costs -- the incremental costs of operating a hydro unit to generate a kilowatt hour is not like determining the incremental costs to operate a
diesel unit to generate a kilowatt hour.

If you want to run a diesel unit and generate a kilowatt hour, you know you need the fuel to operate it, and it's reasonably easy to calculate the fuel, and then you know that you need oil changes at certain hours of intervals and the like, so that you can come up with some estimates of what it costs to generate a kilowatt hour versus not generate a kilowatt hour.

Hydro units are much, much more difficult to do that with. In any given moment the question is, How much more would it cost to take a bit of water that is otherwise going over a spillway instead of run it through a unit to produce a kilowatt hour. It's not insurance. It's not any of those types of items, because those don't vary with generation. It's not water licence fees, because those don't vary with generation.

But it's intended to capture operating and maintenance costs you incur as a result of that one bit more water going through the turbines. But this number is not something that is particularly robust,
Unfortunately. It's very, very hard to estimate. It doesn't hold up very well under -- you know, the range of circumstances people could -- could come up with.

The answer, it's effectively a way of simply portraying that the incremental cost of generating a kilowatt hour with hydro is very, very low. How low it really depends on a multitude of factors.

Q Thank you.

Turning now to oil prices. In answer to YUB-30, YEC indicate that they do not wish to update the GRA fuel cost forecast. If fuel prices remain as they were as of January 22nd, '09, at 77 cents a litre on the WAF system, which was an answer to another interrogatory, will the Rider F become a negative rider and actually return money to ratepayers?

A MR. OSLER: If the fuel price stays below the GRA forecast price for the two utilities, the fuel rider would become negative. And in, say, the number you gave, I think was in the 70s, as you said, if it stayed --
Q  Yeah, 77 cents a kilowatt hour is a number provided by Yukon Energy in response to an IR.
A  MR. OSLER:  Yeah. And so the GRA fuel prices in both utilities' applications are higher than that by significant degree. And, therefore, if the fuel price stayed at that level, there would -- there would be a requirement to pay the companies based on their fuel prices and give a rebate to the customers through the fuel -- Rider F until the situation changed.
Q  Thank you.
A  MR. OSLER:  And, secondary, as well, there would be an issue of keeping track of what the price is for secondary, if the -- in the case of Yukon Energy's application, the price for secondary is also -- which is based on the last quarter of last year in terms of what was being charged to customers, is also higher than the actual price that's being paid by customers so far in 2009, first quarter, second quarter, and what we can see in the third quarter, and the price has been going down, which means that the company -- the customers, in effect, are not paying the price
that's out there, and they -- and the effect on
the Rider F account would be the exact
opposite. It has to, in effect, reimburse YEC
for costs that it's not recovering by charging
the customers and, therefore, that offset, to
some extent, the rebate amount that would be
paid out net through the Rider F account --
through the Rider F adjustments to customers.

Q Thank you.

I have some questions
about peaking diesel. First of all, I'd really
like to get my head around the, if there is
such a thing, the definition for baseload
diesel. We have talked about it in a couple of
different ways, and I would really like to
understand what is meant by baseload diesel.

A MR. BOWMAN: Yes, I can deal with
that. The classic definition of baseload
diesel in the system is when diesel is being
run for energy purposes that there is an
inability from the hydro system over the course
of a period of time, typically a year, to be
able to produce enough energy to supply the
load and as a result diesel has to be run for
energy purposes.
Q And whether or not that happens over a period when you need diesel anyway for peaking is immaterial, correct?

A MR. BOWMAN: Well, the classic other definition is peaking diesel, which is diesel that is run for capacity reasons, not energy reasons. And we spent some time on this, in the resource plan going through the difference between capacity and energy. There are times like now or like last December where the system did not have enough units of hydro on the system, enough wheels turning to be able to produce the instantaneous load of the system and had to run diesel. That's a demand-related quantity of diesel, and we call that -- that's classic peaking diesel. Back when the Faro mine was on and there was 100 gigawatt hours of diesel being run on the system a year, that was -- there is simply not enough water over the course of the year, so we have to run diesel to make up the difference. That's classic baseload diesel.

Somewhere between the two is a grey area as to whether you are running it for peaking or baseload. But classic baseload
diesel is wouldn't matter when you are running it, because you are simply running it to be able to hold back some water. I don't care whether they hold back that water at night or during the day. Each of them goes to keep the lake up.

A MR. OSLER: The models you used in the resource plan, you are correct. Once we got to the point where we were predicting that the energy situation demanded that we start running diesels, we started to create all of the diesel for the sake of just talking about it as baseload diesel. But we would be subject to questioning as to precision in doing that.

Q Yes. The reality of the system is that we now already require diesel peaking in extreme cold weather. If energy requirements increase more, peaking diesel requirements are likely to increase. So one could over periods of cold weather run diesels both for peaking and energy?

A MR. BOWMAN: Yes, that's correct.

Q Thank you.

Now I would like to take you to that Exhibit C4-5 which is the Excel
spreadsheet which was an attachment to YECL-23(b). It's in fact an Excel workbook with three spreadsheets in it. And I apologize for my scribbles. These are from my own notes, and I just made -- copies were just made today.

The first page in that exhibit is what is a tab called "Summary Table," the first spreadsheet. I do not have any questions on that one. But if we go to Tab 2 which is -- well, I'd like to take you to the third page in, which says across the top, "January First Part" which is a screen print from a very large Excel spreadsheet. And in the middle of the page roughly there is a column called "Max Capacity" which I believe is in megawatts, and I just wondered if somebody could confirm to me how that Number 56 was derived and whether it is in fact megawatts.

A MR. BOWMAN: Yes. Maybe I'll, just to be thorough, note the Excel file that this exhibit comes from is the response to YECL-23(b), and it was provided in Excel format with the interrogatory responses as when that response was filed.

What the question was
asking was showing detail how the secondary sales forecast was developed for the test years, but in fact as you note, there's a lot more going on in here than just the secondary sales forecast. The column that you're referencing, as you say, it's a screen shot. The first couple of columns are simply have been data that that goes into this. The first dark column is effectively a number that is an indexed amount of energy over the course of an hour that would need to be generated at some point during the month in question. This is a January month.

Q Yes, January.

A MR. BOWMAN: And what it's saying is that if -- we don't do a hourly forecast for a test year. There is a monthly forecast amount of energy, but there's not an hourly forecast. So how do you know how much peaking diesel you're going to use or how do you know how many hours you're going to have interrupted of secondary sales becomes quite a tough question. And so what this is effectively doing is trying to say that based on what the forecast says we're going to sell
in January 2009. And based on what Januaries
typically look like, starting from the highest
hour to the lowest hour and ignoring what order
those hours occur in, but what is the highest
we tend to have in January and what's the
lowest, what megawatts do we think we'd be
running at any -- from highest to lowest during
all of the hours in January without thinking
about whether that would be on the 6th of the
month or the 9th of the month. And that's
what's in the 2009 forecast with secondary
sales.

It compares that to a
number that's 56 megawatts, max capacity as you
note, which is our benchmark number for how
much the hydro systems would be maxed out at
before people start turning on diesels. And
that number depends a bit on the water flow for
the year. It depends a bit on the time of the
year and how much one is drawing down Marsh
Lake.

But typically when this
system starts to get to the mid-50s, diesels
have to start being turned on. So 56 is the
number that's being used there, megawatts.
Q If we turn the page, I've had to paste the header in. This is in fact from the middle of the spreadsheet, and it's for the last part of the month of July. And I see the max capacity is still at 56 which surprised me. I expected the max capacity available in summer months to be the 40 megawatts from Whitehorse plus if you had the water available up to 30 megawatts capacity from Aishihik.

A MR. BOWMAN: Yes. I know what you are referring to there. If this sheet was being used with a particular focus on July and how the system would be dispatched over the hours in July, 56 would not be the right number. I appreciate that. At the end of the day because it seems to forecast secondary sales interruptions over the winter, it was really only five months that mattered with respect to this part of the sheet. The load duration curves that arise from the index numbers under load ration, those were used in another response, and it gives an idea of what the load duration curve in June or July or August might look like. But if you are only trying to track this portion of the page, the 56 is not a fair
number for July. It's a fair comment.

Q Thank you.

The final page of that exhibit which is the third tab in that spreadsheet, there is a column called "Secondary Sales Potential." The next column is total energy sent out, E.S.O. Can you confirm the secondary sales potential is in fact not the potential but the actual sales?

A MR. BOWMAN: No. Secondary sales potential as the term used on this sheet, the fifth page of your exhibit, is the potential in terms of the market. That is what the potential sales given the customers we have and given the loads they have and given the fact that customers don't buy all the time have a tendency to be broken down once and a while, the potential market is 22.

Q So the potential market of customers connected at this time is 22. That's not the limit of the generation capability of secondary sales at this time?

A MR. BOWMAN: Correct.

Just Mr. Osler was noting for me that you can -- you can see that when we
turn to the tab -- take you to Tab 2 numbers
that of that 22 gigawatt hour potential market,
Yukon Energy forecast being able to supply
basically 16 of that 22. The remainder will go
unserved because it will occur at times when we
have to interrupt for diesel -- for running
peaking diesel.

Q In answer to Leading Edge-16, Yukon Energy
states that the output of Whitehorse Rapids has
varied as much as 7 megawatts from peak to low.

Is this, in effect, the
24 megawatt long-term average that's sometimes
talked about plus or minus 3 1/2 megawatts?
Would that be a fair characterization?

A MR. BOWMAN: It is the -- it is the
generation average for the day plus or minus
3 1/2 megawatts related to the matters that we
discussed in terms of overnight secondary sales
being able to use Schwatka Lake and the like.

It is not necessarily varying around 24.

Twenty-four megawatts is
an output one can rely on depending, you know,
if the -- given the water at Marsh, one can
rely on 24 for the winter. In any given year
it could be a bit, if not a fair bit, higher.
Q But that number would be the midpoint of the 7 megawatt range?

A MR. BOWMAN: It is not plus or minus 7. It's plus or minus 3 1/2.

Q Thank you.

At this time in terms of hydro capability, there has been no discount for possible loss of licence range due to fisheries constraints because we don't have the answer yet. And I understand from an IR that this might be in the range of I think it was 3 to 6 megawatts was quoted.

So if a third turbine -- when the third turbine is in operation, I note that it will produce an estimated 5 gigawatt hours a year additional energy from the water available. It sort of balances, I suppose, the loss from possible range of the licence.

Has -- is -- was that the consideration for not making any adjustments to the long-term average energy available from Aishihik at this point in time?

A MR. OSLER: Just to be really careful here, long-term averages that we have been using change when we add in the Aishihik third
turbine, if we're looking in a forward-planning sense.

The issue that you are talking about to do with Aishihik licencing matters is that there is a constraint right now on the operation at Aishihik in the licence relating to fish issues, and I think the number you are talking about that's in an IR somewhere would probably be in gigawatt hours, not megawatts.

Q  Sorry, gigawatt hours.

A  MR. OSLER: Something like 386 gigawatt hours, somebody may have estimated. It may even be, you know, more than that.

But right now the long-term average that Yukon Energy can generate, if we were getting into situations where we were talking about it as a constraint, is in fact constrained by that licence. What the whole exercise of the fish studies that you were talking about is to try and see if we can use those studies to justify getting rid of that constraint so we could get back to the 351 gigawatt hours.
But if in a couple of years' time that constraint hasn't been removed and we were sitting before this Board, or even sooner, talking ability long-term averages and planning it, we would have to talk about that constraint being in place. And until it gets rid of that constraint, that's all we've got. If we got Aishihik third turbine, it still adds 5 gigawatt hours to whichever situation we're in.

It hasn't been this focal point of the attention today because that constraint, we aren't quite at that stage yet. But everything that we have been talking about is that we are getting there very soon, and those types of issues will be very much front and centre.

Q Thank you.

I have some questions about wind generation now. In answer to Leading Edge-26, Yukon Energy lists a number of difficulties to explain why the wind turbine generation has been decreasing in recent years.

Has Yukon Energy ever contacted wind turbine operating and
maintenance companies for assistance with these turbines?

A MR. MORRISON: Madam Chair, I don't have the answer to that. I would be happy to find out if the operational people have been talking to the turbine manufacturer.

Q I wasn't referring to turbine manufacturers, but to turbine operation and maintenance companies. There are copies that specialize in operating and maintaining wind farms.

A MR. MORRISON: Okay. I would be happy to find out if we have done either.

Q Thank you.

I understand from the response to Leading Edge-28 that there are no plans to bring the wind turbines under SCADA control. Do you know what it would cost to bring the turbines under SCADA control?

A MR. MORRISON: I don't have that number at my fingertips. If you would like me to --

Q Would you --

A MR. MORRISON: -- get it, I'll -- let me say this: I will see if I can get that number, you know, in the purview of these hearings. It may take some time to get that number if we
haven't done any work on it.

Q  Okay. Thank you.

Given the amount of money that's being spent looking for other new renewable resources and developing them, including a potential or new expanded wind plant, do you think it would make sense to spend a little more money on these turbines and get to know how a wind plant would operate when under SCADA control?

A  MR. MORRISON: I'm not sure if that makes sense or not.

Q  Right.

I understand that Yukon Energy has done a prefeasibility study on wind and is looking seriously at the potential for wind energy; is this correct?

A  MR. MORRISON: Yes, Madam Chair, we have. As part of our resource plan, we have followed up on all of the items that were in that resource plan that we indicated that we were going to follow up on, and we have looked at all of the -- for the most part, all of the hydro and all of the other resource options that we have.
Q On April 20th there was an article called "Wind power is not quite an energy cure-all" in the Yukon News. Let me quote, in part, what that says (quoted):

"When wind power goes head-to-head with hydroelectricity, there is really no competition; hydropower is easier and cheaper to produce, said Janet Patterson of the Yukon Energy Corporation."

And further down (quoted):

"Finally, she said, hydroelectricity costs 10 cents per kilowatt-hour while wind power costs 30 cents per kilowatt-hour. 'The economics just aren't there,'...."

Could you please elaborate a little bit.

A MR. MORRISON: On, what, Mr. Maissan?

Q On the -- well, two things. First of all, it appears that, from these comments, that Yukon Energy has already determined that wind energy is not competitive, and I'm surprised
that you will have done a prefeasibility study if that determination has already been made.

A MR. MORRISON: Well, I think to be clear, Madam Chair, we are talking about apples and oranges. We know the hydro business and we know what it costs to generate hydro, and we know a number of the options that we are looking at.

We also know what it costs us on calculation of kilowatt hours of output from the wind and what our costs are if we had to pay for the wind, you know, both on a capital and operating -- if you take both capital and operating costs into consideration.

And our output costs are around 30 cent a kilowatt hour. But that doesn't mean that you wouldn't go and look at a different wind option, or a series of wind options, and see whether or not those costs were going to be the same.

One of the issues -- and I'm not the wind expert; Mr. Maissan is. But one of the issues with the current wind turbines is their location. And as I understand it, part of the reason for putting
them there was a bit of an R&D because their mountain-top wind. And one of the issue we have with them is this Rime icing issue that perhaps I can be corrected on it if I'm not exactly portraying it correct. But I'm not sure anybody's really solved the problem, at least not as far as I'm aware of.

And that's an impediment or a constraint that we have with these turbines. They're not very big; they don't produce a lot of output for us. The real difficulty with wind on a go-forward basis in this system is what we need now is energy not capacity. And the energy from these from our current wind turbines is intermittent. So it's intermittent from A) the wind blowing or not blowing and B) from the operability in winter conditions of the turbines.

That doesn't mean that all wind would be -- you know, you could put all the wind into is the same category. So we looked at -- we made a commitment to look at wind options and whether or not they were feasible, and we have got a draft feasibility, and we will look at it some more. We are still
doing a little work around it. But it's not leading me to believe that we are any more competitive than -- the price might be a little bit cheaper, but not going to give us the same kind of energy we need from -- to meet system demands that hydro will.

Q Would you be prepared to table with this Board the background calculations that go into these two numbers, the 10 cent a kilowatt hour and 30 cents a kilowatt hour?

A MR. MORRISON: I will be happy to table our calculation on the wind. But I believe we have already discussed that at the previous resource plan hearing. I -- and I have a bad memory -- recall discussing that same information with the City of Whitehorse during those hearings.

Q Is this number a levelized cost of energy, the 30 cents?

A MR. MORRISON: I can't tell you that off the top of my head.

Q I would appreciate the basis for those calculations, those two calculations being provided.

THE CHAIR: Just for the record, I
have Mr. Morrison agreeing to do that.

A MR. MORRISON: Yes, sorry, I did.

THE CHAIR: Just clarifying.

Q MR. MAISSAN: I understand from the various responses about demand side management that in recent years, Yukon Energy has not contributed financially to DSM type of programs; am I correct?

A MR. MORRISON: That's correct, yes.

Q The Board has recently issued an order which requires Yukon Energy to work with Yukon Electrical on demand side management. And in answer to UCG-20, I believe Yukon Energy indicates that it is looking for further direction from the Board.

Can you please explain what direction you require from the Board to pursue DSM further?

A MR. MORRISON: Let me just say this: We will be looking for some further clarification, but not on whether or not we should undertake a joint DSM initiative with YECL. We will look for some clarity around exactly, you know, the -- I guess the breadth and depth of what we're going to do. But we have been asked by
the Board to do it; we will do that.

Q Thank you.

I believe the board order requires or asks Yukon Electrical and Yukon Energy to table their plans at the next GRA. And I suppose I am wondering when the next GRA is going to be. It seems unlikely it would be for a 2010 test year; likely to be later.

If the utilities wanted to institute, implement a DSM program prior to the next GRA being tabled, what do you think would be required from the Board?

A MR. MORRISON: Sorry, just so I'm clear, were you asking if we wanted to implement something along the DSM lines before the next GRA?

Q Correct.

A MR. MORRISON: Well, I may be wrong, but my understanding of DSM costs the last time we talked to the Board was we weren't very successful. So I would say to you at this point, in my thinking, that before we moved into a -- you know, a formal DSM program, that we would be back asking the Board whether or
Q Thank you.

Can you turn, please, to UCG-59 (d). UCG-59 (d) asks about various things, including discouraging consumption overall or shifting demand to less costly periods, and they also talk about other things, including critical period rates.

The answer provided addresses the critical period rates but doesn't specifically talk about seasonal rates or daily rates. We already know the diesel peaking is not required for 24 hours a day. So it would seem that a daily rate, daytime rate, versus a nighttime rate might have some applicability. We also know that diesel is required in winter and not in summer, so some kind of seasonal rate may also have some kind of applicability.

Could you explain why you would not consider these kinds of options, or would you?

A MR. MORRISON: Just again so I'm clear, Madam Chair, we are talking about options that would increase our sales or options that would look at different rates for different periods.
of the day from a conservation point of view?

Q We're looking generally at rate structures that
would, I guess, discourage consumption during
high periods and perhaps, by difference,
encourage consumption during periods when hydro
power is say available, i.e., encourage the
summertime, discourage wintertime; discourage
daytime, encourage nighttime.

And demand-side
management is not just increasing or decreasing
sales. It could be just shifting sales around
to less costly periods.

A MR. OSLER: Right. That's -- the
full concept of efficient -- encouraging
efficient use includes the concept of
encouraging more use when you have a surplus.
So it's -- secondary sales is part of -- in
many jurisdictions, part of an DSM concept.

Right now our minds are
fixed on the secondary block and efficient
price signals for that level of use. The
concept of time-of-use pricing of some type or
seasonal pricing of some type has been raised
by many parties for ten or more years. It
hasn't had much relevance during the period of
surplus, so the question is, Will it now have relevance as we move into the type of future we are talking about? I suspect it will be part of a discussion, so, you know, because people will raise it and we will have to examine it is the first part. It won't be dismissed out of hand.

I would just say this at the moment: In hydro-based jurisdictions, such as Manitoba or British Columbia, the time-of-use concept hasn't tended to take off to the same extent as some other jurisdictions. So to the extent that we are really relying on the grids on time of use -- sorry, on hydro based resources, we may see that it isn't really worth the effort to go through time-of-use pricing. And if you are looking at the other systems that are relying entirely on diesel, there is no particular apparent reason to think of time-of-use pricing.

So although it sounds like it's logical and we should all jump for it, there is a cost to implementing it. There is a whole bunch of rate-design issues that come with it, and I have experienced the
situation more than once, Manitoba one case, where people looked at this seriously at the industrial level and the utility level for a year, and in the end everybody came to the conclusion at that time that it just wasn't worth it.

So, you know, it wouldn't surprise me that we will talk about it, and it wouldn't surprise me if it didn't get acted on in the near term, for those types of reasons. But we weren't trying to suggest it would be dismissed out of hand in the answer here.

Q Thank you.

In Leading Edge-25

Yukon Energy says it uses electric heat itself only when available from surplus hydro. Can you confirm, then, that there is no electric heating in any of the hydro plants or other pieces of Yukon Energy equipment? For instance spillway gates and trash racks?

A MR. MOLLARD: Sorry, Mr. Maissan, just to be clear, the question refers to space heating in the plants?

Q Just let me refer to that, sorry.

Your answer provides --
talks to space heating, not to other electric forms of heating?

Q "Such as"?
A MR. MOLLARD: "Such as"?
Q "Such as"?
A MR. MOLLARD: Yes. There is a qualifier there.
Q So it sounds like an example as opposed to --
A MR. MOLLARD: Yes.
Q So what you are saying is there is electric heating in trash racks and spill gates, et cetera?
A MR. MOLLARD: That is correct.
Q Thank you.

Turning now to staffing levels and Leading Edge-32. On page 2 of 6 of Leading Edge-32, at the bottom, I see in the -- sorry, you have that?

I see at the bottom of the page that through the period 2005 to 2009, in fact to 2008, the operations staff was increased from roughly 33 to about 40, which is, in round numbers, a 20 percent increase. Can somebody provide an explanation for that increase in operating staff?
A MR. MORRISON: So, Mr. Maissan, are you looking for something more than has been supplied in the answer?

Q Yes, please.

A MR. MORRISON: Can you help me out a little bit?

Q Well, you have listed the positions.

A MR. MORRISON: Yes.

Q And you go through each of them. But, you know, on a big-picture perspective, I don't understand, I guess, why the overall numbers just, you know, look really huge.

A MR. MORRISON: I'm happy to -- I'm happy to try to help you, but I'm not sure what you are looking for. You are looking for a better explanation of what we have got here? Are you looking for more? I mean, we have given you the position; we have given you the reason.

Q Yes. And each of the -- each of the explanations doesn't sound unreasonable. But when you look at the overall numbers, it seems -- it seems a very large increase.

A MR. MORRISON: Well, if you want to --

A MR. MOLLARD: Just some of the general things we think about when we look at our
staffing levels, if this is perhaps helpful, I mean, we have added significantly to our asset base in terms of kilometres in transmission line that we are dealing with. We have mentioned on a number of occasions the ages of our asset and the assets that we need to do continued maintenance on those and our reliability issues that we need to deal with.

We have new regulation all the time that we have to deal with. That doesn't speak necessarily specifically to operations, but we do have new regulatory regimes that we are having to deal with, and those sorts of things that are coming up sort of that we have to deal with and need people to deal with them, if that helps.

A MR. MORRISON: And, Mr. Maissan, sorry. Let me try to help as well too. I was just trying to look at kind of where you were zeroing in on.

Q Maybe I can help a little bit here, because the next question would be that I am surprised with the technical expansion, all the additional equipment, that in fact engineering services have gone down. And when you see is a decrease
in engineering staff with an increase in
facilities and an increase in operations, I'm
just wondering what's happening with those.

A MR. MORRISON: Yeah, I would suggest
that part -- just excuse me for a minute.

So I just wanted to
confirm that I was on the right track. I
wouldn't look at it that way at all. What we
have done is we have moved some people who were
in engineering into operations. So it's just a
structural change in that respect. So they
haven't -- those tasks are still important.

We have also -- it's been
very, very difficult to hire electrical
engineers, specifically over this period of
time that we're looking at. So some of that
work is being done by contractors out of
necessity, because it's been almost impossible
to hire electrical engineers.

I don't know why
specifically through this whole period
electrical engineers, but there was a period
when we were having a difficult time hiring
power linemen as well. And I understand that,
because it was a very busy period in the
industry, and there was lots of -- a lot of line construction and, you know, just a shortage of personnel. But just generally we have difficulty with that.

But in all this expansion, when I look at this in terms of people, it's been -- I mean, there is a number of things, and Mr. Mollard alluded to them, about additional -- not only additional facilities in terms of two large new transmission lines but we have also had a very significant increase in our load and our operation of the facilities has been on a higher level over the last number of years as well. And that also requires additional maintenance, additional capital planning, and all of those resources.

But on the regulatory side of things, we have experienced, you know, a really substantive increase in what I would call "regulatory affairs." Not just -- and I don't mean by that proceedings such as this. I mean on the environmental side the amount of permitting and environmental management issues that we have to deal with through environmental
legislation, through compliance with things like our YESAB processes and permits.

You know, we at one time thought we could deal with health and safety and environment all in one little position, and we can't deal with either one in a position barely these days. The amount of work that has to get done to comply with regulators, to comply with occupational health and safety regulations and WCB processes, as I said within environmental regulations, we can barely keep up.

In all the workload increase has been very significant for Yukon Energy. We are not a very big company. I would say to you that for a number of years the staff complements were far too low to get the work done that had to get done in order to efficiently operate the asset base that we have and to comply within the regulatory and legislative regime that we have to comply with. And that's strictly what all this is what you're seeing.

Q Thank you.

A couple of questions of
clarification on brushing. Could you tell me roughly what the total length of transmission lines were before the Carmacks-Stewart line was added.

A MR. MORRISON: We are just going to see very quickly if we have got that number.

Q In the order of 5 or 600 kilometres?

A MR. MOLLARD: I believe it's 600 including the new line.

Q And I understand from the information provided in the application that you are looking at brushing about 80 kilometres per year. Is this sort of the -- is that the brushing level that you feel is necessary on an ongoing basis to be done each year, about 80 kilometres a year to keep up?

A MR. MOLLARD: We are -- our operations personnel advises us this is sort of the leading edge of a cycle and that the 80 kilometres would represent a reasonable level in order to get caught up over the next three to four years, starting in 2009.

Q Right. Okay.

So the average frequency of brushing is, if it was 600 kilometres
divided by 80, about seven years --

A MR. MORRISON: Yes. And when I think I talk about that yesterday, Madam Chair, what we are noticing in some areas is -- and Mr. Maissan, I think, has reminded me, and I couldn't remember yesterday what year it was. We were on a seven-year cycle. We are paying attention to the brushing, and with wet conditions, we are finding that in some areas, you know, we have to look at it, you know, on a more frequent basis.

Q Yeah.

Turning briefly to return on equity. Are project capital cost overruns part of the risk that a generation/transmission utility would face?

A MR. OSLER: Could you repeat the question.

Q Yes.

Are capital -- are project capital cost overruns part of the risk that a generation utility would face -- generation and transmission utility would face?

A MR. OSLER: Well, I think generally speaking, any utility that's involved in
capital programs has a risk that the budgets that they establish for a program may experience overruns in the actual result. So, I mean, I don't think it's unique to generation and transmission utilities, except that it may be relatively more important if the generation utility and the transmission utility involved as a primary activity in capital development that is -- in development of new facilities that are very capital intensive, which would be a bit different than perhaps the relative distribution of costs within a distribution utility.

So if that's what you are getting at, in that sense it may be a bit more relevant to a generation and transmission utility that's in a development phase.

Q Right.

And in regards to the substantial capital projects that have been completed and are being anticipated, we have seen some significant levels of government funding. Do you think that in any way mitigates any of that risk?

A MR. OSLER: Well, my mind's getting
technical, but Madam Chair, the risk exists independent of the budgets that are set. The risk is that you will develop a budget that is firmly developed with all the engineering and tendering and everything else, and you then approve at the board of directors' level going forward.

So if we're talking about cost overruns in the question, I think that's the context we should assume we are talking about it in. a decision made to go forward with the right information and then experiences an overrun.

You would know what funding contributions you are going to get at that point as part of that decision, you would normally assume. The risk of an overrun is still the risk of an overrun. It isn't mitigated because somebody agreed to pay for 20 percent of your cost based on the budget.

And if I go one step further, I'd say, to the extent that you are getting a lot of contributions, it's clear that the contributors usually are not agreeing to pay for the overruns. That isn't always the
case, but it's -- it's not abnormal to assume, if you are using government as an example, that they agree to a fixed amount. They don't agree to, you know, a contingent amount, up to a certain amount, I'll put it that way.

So from a utility point of view, developing something with those types of contributions, first of all, the risk hasn't been mitigated at all by the contributor; they just contributed to reducing the total cost based on the budget, and the utility still has to deal with the risk to the total program in terms of possible overrun. I think we talked about that a bit yesterday with Mr. Keough.

**Q** So an absolute amount reduction, for instance, the Phase II transmission project, if it's a $40 million budgeted project and you received contributions of 35, then the risk of going from a net cost of 5, say, to 10 million, you would view no differently as a risk of going from 40 to 45 ratepayer costs?

**A** MR. OSLER: It would be the risk of going from -- having a $5 million overrun imprudently incurred costs. Because if it's not prudently incurred, there is no risk to
ratepayers; the Utility Board won't allow it to
be included.

But assuming it's
prudently incurred costs, the $5 million risk
is a risk the utility has to observe and
monitor and manage on behalf of ratepayers
because nobody else is going to pick it up.

Q All right. Thank you.

Canada Trust note, that
was talked about at length. The one thing I
was a bit uncertain about was when this note
becomes due in 2011, are there plans in place
to refinance it with YDC, or are there any
plans at all yet in place what to do with that
facility when it comes due?

A MR. MORRISON: We have no firm plans on
what to do with that note when it comes. We
will look at financing at that time and see
where we -- see where we're at.

Q Thank you.

In YEC's application at
page 515, there is an indication that vehicle
purchase in 2008 would cost $209,000, whereas
in response to UCG-83, there is an indication
that the actual cost, if I'm reading this
correctly, was 110,700. Is this correct? Is this the same vehicle purchase that's being referred to?

A MR. MORRISON: If you can just give us a minute.

Q Sure.

The application page 515 and UCG-83 were the two references.

A MR. MOLLARD: Just to be clear, those do refer to the same budget. I believe the application refers to service bodies. I don't believe the three units purchased were all service bodies.

The -- my recollection, subject to check, is that the -- when the forecast was done for the 2008 business plan, they -- they have to anticipate which units are going to hit their limits for replacement in a given year. And for two of the units that didn't happen, so they weren't required to be replaced.

Q All right.

I wondered whether that was a saving that was realized in 2008 and wondered whether a similar percentage of saving
could be expected in the vehicle purchase plan for 2009. And I guess I was wondering whether that is in fact related to the almost fire-sale prices available on new vehicles these days.

A MR. MOLLARD: I believe we still have the same plans as in the application to buy two service bodies, and I don't believe we're getting a deal on those.

Q Okay. Thank you.

One of the things in the capital plan as well is a tracked vehicle that is proposed to be purchased. Let me find the reference. It's in the application on page 5-16, off-road maintenance vehicle purchase. I just wanted to understand a little bit more about this vehicle.

This is a large track vehicle, something like what I think you call a digger truck, except on tracks?

A MR. MOLLARD: Its purpose built. Its brand name is a Nodwell, with a flat deck and a crane on it, so it can do similar functions to a digger-type truck.

Q Right.

And how is it moved
around if it's on tracks?

A MR. MOLLARD: Lowboy truck, truck and trailer.

Q So it requires a third party to move this?

A MR. MOLLARD: That's correct.

A MR. MORRISON: And just to add a little clarity to that, we have been renting one of those or leasing one of those vehicles for several years. And we did the -- we did an analysis, and it was clear that, you know, buying the vehicle was a much better way of going than leasing. We started out leasing it unsure of really how much use we really had for it. When we looked at the cost, buying the vehicle was a much cheaper alternative than leasing it when we needed it.

Q Yes. And it's a type of vehicle that can be used winter and summer?

A MR. MOLLARD: It is outfitted to run in the winter as well, yes.

Q I see in the specification, it's got an Arctic pack, including a 40,000 Btu cab heater. This means that even in the severe weather, if you have got transmission problems, the crew can be out and work safely from this vehicle?
Q Have you a rough idea of what percentage of
time you expect it to be in use versus on
standby?
A MR. MOLLARD: I don't have that number, no.
Q In regards to the Carmacks-Stewart transmission
project, in YECL-9, on page 2 of 3, there is a
description of the scope changes.
A MR. MORRISON: We will get there as
quick as we can.
Q Sure.
A MR. MORRISON: I think we're there,
Mr. Maissan.
Q Are you there?
   Yes. And there are a
couple of scope reductions that are described
here: one which was deferral of the
Pelly Crossing substation, differed to Stage 2
and the $2 1/2 million saving, and there was
also the more complex substation at Carmacks
that was reduced to a switching station. And I
wondered if there was a ballpark number as to
the cost saving on that substation.
A MR. MORRISON: That's not a number I
have at my fingertips, Madam Chair.

Q Is that one that you could provide or ballpark?

A MR. OSLER: Not easily, because you are -- the numbers that are put in here are numbers that I'm not even sure are always met. So if you go back to the initial cost estimates brought to this Board, Madam Chair, the substations in general were very low-budgeted amounts. The ultimate result is that the substations were considerably above even the cost estimates in the preliminary engineering.

So the amount of money that was in the initial cost estimates for whatever we were thinking we would do at Carmacks would not be a very big number, just as a common sense observation.

The bigger numbers in the original cost estimate, and they were still very small numbers, were at Minto Landing and at Pelly. And the Minto Landing number was assumed, Madam Chair, to be part of the spur line.

So when people would got to preliminary engineering stage in June of '07
and started seeing even the preliminary engineering estimates and were looking for ways to manage the budgets and everything else for Stage 1, decisions were made at that point to take the approach we took at Pelly Crossing.

I don't know that $2 1/2 million was saved in the gross sense. It sounds to me that it was somebody's estimate at that time of what it would cost at Pelly Crossing. We did incur costs as part of the package to do the work at Minto Landing. They were nowhere near 2 1/2 million, but I don't know what they were, and I don't know how we'd -- you would have to go and talk to a bunch of people to get an estimate of that.

The final costs, of course would affect this also. So it had become an analysis rather than something you just go and find. We don't have it sitting -- the decisions were made on a decision basis step by step, but they weren't necessarily all documented in a final nice way that we could discuss today.

Q And -- sorry?

A MR. MORRISON: Just to be clear,
specifically at Carmacks, one of the reasons that there is the scope changes is when we got our heads around what we really needed in terms of the operability of the system, and we had some of our -- some of the engineering people look at it and some of our engineering advisors look at it, there was a realization that they really didn't need the Carmacks substation that was previously proposed. And what we went to was a -- you know, from a design engineering point of view, was what was needed versus what somebody thought we had needed previously.

Q So there were no compromises in terms of operating the system?
A MR. MORRISON: Absolutely not.
MR. MAISSAN: Madam Chair, I estimate I probably have about half an hour left. Should we take a break at this time, or would you like to --
THE CHAIR: We had indicated we would like to have a break at 3:30. So could you try and finish up around 3:30?
MR. MAISSAN: Sure.
Q MR. MAISSAN: Minto diesels. I asked about the RPM of these units, and it wasn't
clear from the specs provided; are these
1,200 RPM units?

A MR. MOLLARD: They are high-speed
units, but I can't recall off the top of my
head.

Q High speed might mean 1,800 versus 1,200. Can
you get back to me on that?

A MR. MOLLARD: I can get back to you.

Q The other question I have is, fuel efficiency,
when they are running in baseload operation,
would you have a number for that as well or
could you provide that?

A MR. MOLLARD: We can get that for you.

Q All right. Thank you.

In the application on
page 510, Yukon Energy says that new diesels
for the Minto project would have cost an
estimated 6.6 million, or 1.035 million per
megawatt. Does this estimate include the
issues like winterization and heating systems,
more solid buildings, foundations, data
connection, remote start, and visibility that
are things that you needed to add to the used
diesels as well? I just wondered if that
comparison is an apples-to-apples comparison.
Q To apples -- for instance, you had to add these additional features to the used diesel units, and I wondered whether the same features were part of the 6.6 million estimate for new diesels, i.e., or would these new diesel have cost 6.36 million plus these other modifications?

A MR. MORRISON: I understand. It's my understanding, and subject to checking with my other, colleagues here, that the 1.1 per megawatt, the $1.1 million per megawatt, is for the diesels themselves. So whether they're new or old, we still have to do the other work.

Q Right. Okay. So the new diesels would have needed the same --

A MR. MORRISON: They would have needed a building. They would need all the other things that arises with that.

A MR. OSLER: And in this case of this situation, you were looking at a building and certain installations in place, you weren't creating a new diesel plant, so the rationale for that assumption isn't far off.
The question of actually figuring out how many extras you have to do for the new diesel, probably it's a bit conservative if you want to look at the number. You would have to get into more work, which wouldn't be worth doing because you've already proven that it's not cost effective.

Whereas with the other ones, you have been pushing yourself to make sure you've thought of all the little things you've got to go to get the total budget, not just the cost of whatever is the most -- the first ten things you think of.

So, if anything, if we're correct, and we'll get back to you if we're not, this number should be for the reasons you just gave a bit low for the new diesel. And if you were trying to build a new diesel plant that didn't exist, it would certainly be more than this because you'd have to spend all the money for the building and everything else.

So, you know, you'd have to keep in mind the context of this estimate.

Q Sure. Thank you.

A MR. OSLER: We'll get back to you.
Q Thank you.

In Leading Edge 53, you described the process that you would go through for specifying large transformers for energy efficiency at, you know, the lowest life cycle cost, et cetera. Is this something for which you might have an example that could be provided?

A MR. MORRISON: Can you just give us a second.

Q Sure.

A MR. MORRISON: Sorry, I think in looking at the question, we have lost your question. Could you repeat it for us. It was LE-53?

Q Leading Edge 53, yes. The process for specifying transformers is described, and I wondered whether there was an example available that you could provide from a recent purchase?

A MR. MORRISON: You want to see the specifications of a transformer; is that what it is?

Q Yes. Yes. See what would have gone out to the -- to the manufacturer.

A MR. MORRISON: I guess we can provide it. We have it. We can certainly provide it.
I'm not certain how much benefit it will be for you, but . . .

Q All right.

A MR. MORRISON: We will certainly do that, if it's all right.

A MR. OSLER: But wouldn't you really -- you know, you're trying to get at how do you know what the most economical approach is taken, and you asked something about life cycle costs. Are you asking whether or not the specifications put out request the people to tell us life cycle costs? Is that what you're getting at?

Q Well, what's described here is -- well, let me just reread it and I can be more specific in my question.

You provide to the manufacturer, it says the load and no-load costs based on the kilowatts quoted to you on energy by the manufacturer. Yukon Energy uses a quoted loss bigger in the costs provided to determine the overall cost of the transformer over its life.

So what I'm looking for is just what does -- what are the numbers that
Yukon Energy provides to the manufacturer as part of requesting the quote?

A MR. MORRISON: We'll get that, Madam Chair.

Q Thank you.

Leading Edge 56

references the page 515, line 6 of the application, and it has to do with spill regulation at Whitehorse dam, and it seems to imply that a study is to be done on the spill regulation, and I wondered whether that was complete now and whether the expected expenditures in 2009 would happen as planned or whether this project has been deferred?

A MR. MORRISON: Madam Chair, this study hasn't been completed.

Q So will the anticipated $200,000 worth of work to be done in 2009 take place still this year, or --

A MR. MORRISON: I would anticipate that it would, yes.

Q So you still expect the study to be completed this year in order to do the work for this year?

A MR. MORRISON: Yes.
Q Thank you. Question Leading Edge 58, electronic document management. This references the application page 517, line 15. And it appears that a consultant was to be hired to review the -- and assess the records management and to come up with proposed solutions, and I just wondered whether this has taken place.

Obviously from the response, that there has been no report, but I just wondered if the activity has taken place in a form other than a provision of a report?

A MR. MORRISON: No, not yet, Madam Chair.

Q Not yet, thank you. In regards to the power line carrier system, Leading Edge Question 59 references the application page 517 and incorrectly, Madam Chair, references line 15. That should have been line 28.

I understand that Yukon Energy is replacing the Takhini to Faro power line carrier system. Do I correctly interpret that from the answer, as opposed to the Takhini-Aishihik system?
A MR. MORRISON: Sorry, Mr. Maissan, just could you repeat that again. I thought I missed the first part of it, so . . .

Q From the answer, the application proposes to replace the Takhini to Aishihik power line carrier system?

A MR. MORRISON: Right.

Q I understand from this response that that is now on hold and that the Takhini to the Faro substation is being looked at I think, including the new Carmacks-Stewart Phase I project. Is --

A MR. MORRISON: Yes, that's --

Q Is that right?

A MR. MORRISON: Thank you for that. Yes, Madam Chair, that's correct. We're having some technical questions around what is the best solution for Aishihik. We thought we had a solution working with Northwest Tel, but as it turned out, there were some technical problems more from the line of sight of Aishihik and how we get there, so we're having to reassess the options for that. That's why it's delayed, because we don't have the correct technical solution yet.
Q Is there any changes in cost due to this change in focus from one system to another?

A MR. MORRISON: Changes in cost in terms of instead of doing Takhini to Aishihik to Takhini --

Q Forecast, yes.

A MR. MORRISON: -- to Faro?

Q Now that you're --

A MR. MORRISON: I don't have that number at the top of my head, so . . .

Q Fair enough.

The next question I have is in regards to the Whitehorse-Aishihik-Faro transmission upgrades. I understand that there are these various projects described as in the application at page 518 and after that. And I was wondering whether this work is being done by contractors or by some of the Yukon Energy crews, the additional linesmen, et cetera, that have been hired?

A MR. MOLLARD: I believe that the answer is both. Some of the items specifically I can say. With respect to the insect infestation, they have to get contractors because it's a specialized technique, but the general upgrades
we'll be doing with internal crews.

Q And will your new track vehicle be in use on these projects?

A MR. MOLLARD: We're supposed to get it at the end of this month.

Q My next question is on deferred costs, and first of all, sort of a more general question. This references the application page 520. The deferred expenditures of 6.8 million are referenced here, and I understand from response to YUB-38 that this figure is now down to 4.3 million?

A MR. OSLER: YUB-38 has indicated that the number has been reduced to 4.3 million at the moment. You know, that's the more -- the most recent estimate.

Q Thank you.

Is there any capital cost range estimate for the Gladstone project? I notice it says that it's potentially very cost-effective energy, and I just wondered if there was a number you were prepared to or a range that you were prepared to mention at this time?

A MR. MORRISON: Madam Chair, no. I'm
reluctant. The reason that we would think of
Gladstone as a very cost-effective project is
because there's very little structural work
that has to be done for the amount of gigawatt
hours of potential production out of it.

So it's very early days.
We have done very little work on the Gladstone
project. It's one of those projects that
isn't -- won't have a high capital cost just
because you don't have to do a lot of work.
It's the same as building a little -- it's a
little control structure, a small weir.

Now, small in our terms
might mean several million dollars. But, you
know, if you look at it in that sense, the
potential to get 18 gigawatt hours of
additional energy out of the Aishihik system, I
come back, you know, just in very general terms
to this concept I was talking about earlier
today.

If we just look at -- if
we had to provide 18 gigawatt hours of energy
and we could get this energy in the winter out
of Aishihik, which is very valuable, and let's
just say instead of getting it from the hydro
plant we had to get it from the diesel, we're talking about, you know, in the neighbourhood of $5 million to $6 million worth of diesel per year every year to generate that same 18 gigawatt hours.

So if the diversion at Gladstone costs even 10 or 12 million dollars, it's very valuable energy. It has a very quick payback. It's energy we get in the winter, which is tremendously valuable for us.

Now, technically it is not a difficult project, but it's an issue -- well, this is an issue, and Atlin and I would put Marsh in the same category, they will be very difficult to licence because they're -- they don't -- you know, the getting people to understand, you know, why we need to do these things and why we want to reverse water flows is very difficult.

There are a whole bunch of stakeholders in each of these that are involved, none of whom are particularly, you know, joyous about us going ahead and doing a project in their area where they have interest.

So Gladstone will be a regulatory process that...
will be very difficult, and so will Atlin from that point of view. Atlin is virtually the same kind of project. It's a small control structure on a river that controls water.

We have -- we are in the process of engaging some consultants to help us develop those projects on a technical basis and we'll have some more information. But I wanted to -- just add to this, this is about the most important thing that we do outside of, you know, our mandate of keeping a reliability and cost -- providing cost-effective electricity.

This is the long-term planning that we are mandated to do in YDC's legislation, that we are required to provide to ensure there's enough power available on the system for Yukoners. And if we don't do these things and if we can't implement some of these things, the solution is diesel, and I don't think that's our mandate.

I think our mandate is to look forward on the long term, make sure that we've got enough power at least always coming forward whether -- you know, we're not a big system. We can't be sitting out there with a
100-megawatt dam that we can just grow into because we have to pay for it.

So it's really tricky from our perspective trying to stay 5 and 10 megawatts ahead of growth because you can't build a hydro plant or you can't develop these projects as quickly as you can develop a diesel plant. So if we wait until growth catches us, that means we'll be running diesels, and so it's this very tricky balance.

And I know we talked quite a bit yesterday about the risk and who should take the risk and whether there were government contributions. Well, a big part of our strategy has been if we can get infrastructure contributions to build these projects, including Carmacks-Stewart, including Mayo B or the Aishihik project, which we have a 5 million contribution from Canada and the Yukon government to help build, those help offset that risk of the small system where we don't have very many customers, we're not connected to a big grid, and at the same time, we can get some projects into the system which don't put a lot of ratepayer -- they don't add
burden to the ratepayers. They're not coming into rates.

Thinking about the benefit of a contribution that the government and the -- and the customer Minto made to the -- keep the Minto or the Carmacks-Stewart line down to a 3 or 4 million dollar asset from the ratepayer's point of view in terms of cost, it's a benefit that the ratepayers get forever. I mean, that line is always there. It's always available to sell power over. And, you know, the ratepayers are paying 3 or 4 million dollars for it.

We have to be able to plan and find -- and we've been trying to find strategies to minimize costs to ratepayers, but one of the strategies that we feel very strongly about and is very important is the need to do these studies, the need to be looking very, very critically. And we have very critically looked at them, because if you recall, we came to you in 2005 with all of these in the resource plan and said they needed to be looked at, and we're looking at them.

We try not to overspend
on them. We try to balance what we're going to spend in one year by keeping it to a reasonable level and trying to find ways to mitigate that risk going forward with capital contributions for new projects. But these projects are absolutely some of the most important things that we're doing right now, specifically those projects.

Q Thank you. That's the next lead into my last couple of questions on Mayo B. And, you know, by comparison to these other projects you describe, and Aishihik third turbine among them, Mayo B is, you know, on a cost per megawatt and a cost per gigawatt hour per year basis, extremely expensive.

And even the Aishihik third turbine, which is principally for capacity, produces energy at, well, less than 2/3 the cost that the energy from the Mayo plant has gone to cost based on $120 million and 9 million for the third turbine.

And so I wondered whether we were really focusing on the right projects, because when you take Gladstone and Marsh and third turbine and Atlin and put them all
together, there is more energy there for Mayo
and potentially for Mayo B and potentially at
much lower capital cost.

And so I was just
wondering about priorities of where we're
spending our capital dollars, regardless of
whether they are ratepayer dollars or taxpayer
dollars.

A MR. MORRISON: Madam Chair, you know, it
is a very valid question and very valid
concern. I think we talked yesterday again
about the fact that Mayo B at 100 or 120
million dollars is not a project that we could
even consider going forward with without a
significant capital contribution from someone
else, and that at the moment is probably the
Federal Government and perhaps the Yukon
government in terms of assisting us to acquire
the kind of dollars we need to do Mayo B.

We are very cognizant of
the fact that we can't -- that Mayo B's
expensive per megawatt of installed capacity if
you look at it, but it has some real advantages
from our point of view. A, from a hydro
perspective, basically it's a brown field
development. It already has a dam. We don't have a rebuild a dam. And I would say to you that anywhere we have to think about a dam, it just adds years of regulatory time into the process.

So one of the reasons we're looking at Mayo B is we can build it quickly because the basic infrastructure is there. We have to -- we have to build a canal and a tunnel and a new powerhouse, but we already have a powerhouse, we already have an operation and an intake in that area, so yes, it's expensive. But from a regulatory point of view, it will take time, but it will take not as much time as trying to start from scratch.

The other important part about Mayo B is it's the only hydro project that we have in the development stage that can be built within the time frames that we have where we're going to -- where we anticipate or forecast we're going to need the power. So we have a lot of other hydro studies, but none of them advanced to the stage and none of the projects advanced to the stage where they're ready in a two- or three-year period to bring
And that just really, really emphasizes the point I was trying to make earlier about the need to do research, the need to do planning and system studies on an ongoing basis, because we have to get some projects up to the point where they're shelf ready, and we can then take them off the shelf when we encounter these increases in load.

I mean, the best scenario is we start -- we're always in a planning mode and we always got something going forward. But the reality of it is when we brought forward the resource plan in 2005, nobody had done anything for years prior to that. So starting in 2005, we've got to this stage.

And I think you should -- we can look at that as saying that's where -- you know, it's taken us four years to get to where we're at today from starting where we were, and we can't let that happen again. We need to have the planning studies done, we need to have the information within the system, we need to spend a bit of money to make sure that when we've got new loads coming to the system
that we’re not pulling out the diesel card and
saying, Okay, well, let’s just stick diesel on
the system, because diesel isn’t 20 cent a
litre anymore.

And, you know, whether
it’s 70 or 80 cents today, you know, it’s not
coming back to the 20 cent level. Maybe it’s
not going to be 1.50, but it’s certainly -- you
know, it’s going to be high, and ratepayers
can’t afford that diesel cost on the margin.

The problem with projects
like Mayo is, you know, if you’re in a large
connected system, you know, it’s a blip in BC
or any place else. We’re a tiny little
jurisdiction. We don’t have a lot of
customers. So we have spent a lot of time
trying to make sure if we are looking at
something like Mayo B, that we’re trying to get
some money, enough money to make sure that, you
know, we’re not doing these projects in a way
that’s going to burden ratepayers.

And Cam might --
A    MR. OSLER:    I’ll just add one thing
to the question itself. Yukon Energy’s
assessment as of mid ’07 was that they needed
to go out and get a priority of what they could get in terms of energy from renewable resources in the period 2010, 15 in, say, 25 to 50 million kilowatt hours range. And as we went through the next year after that, we realized that probably we should be asking the question more like 50 to 100 million kilowatt hours.

So the board of directors when we look at these matters is saying, We need all of these projects. We need the Gladstone, we need the Atlin, and we need the Mayo. And it's not that we're giving one more priority than the other. It's just that, you know, the Mayo project can be acted on in a decisive manner by doing some work and then filing an application with, yes, I've been trying to get some government funds. The others ones are being acted on too, but they require us to go through some relatively prolonged regulatory processes that we can't predict the outcomes of. If we get through the regulatory processes in 12 months, you could probably have the facility in place at "a very simple cost." You just got
to get through Step 1.

A MR. MORRISON: And just to re-emphasize I think the point that Mr. Osler is making, we don't need Mayo or Atlin, Gladstone, Marsh. We need Mayo and all of those just to meet a very -- what I would say to you is a very conservative load forecast going forward for the next five -- four or five years, a very conservative, because it has two mines in it, that's it, one of which we know for sure and, you know, is moving ahead or we feel pretty comfortable with, and the other one is sitting there, you know, in kind of a holding pattern. But that accounts for nothing else going on in the Yukon.

And, you know, estimates I have seen even within the City of Whitehorse more recently and just a few days ago, if some of those loads happen, you know, we're going to have to add -- quickly add to those projects.

A MR. OSLER: And bottom line behind those things is in the last 12 months, we know that Minto is plaining to increase. They are going to be making their applications so that the number they are looking at right now is not
the number you should be assuming for a couple of years from now.

And there is a Faro reclamation plan that we're told will add a material amount of energy requirements to this system and will go on for some considerable number of years. So in the last 12 months, I haven't had anybody coming in telling me why we should really reduce this except for the fact that Minto's numbers when we started up were a little bit lower than we thought they were going to be given what they had told us, but they're learning like everybody else what they actually will need.

And they have to be conservative when they're talking to us, they have to make sure that we've provided enough for them, and then they'll do their best to keep it as low as possible. That's fair.

A MR. MORRISON: Just to be clear, the Faro reclamation load is as big as the Alexco mine load in the near term, and I have no idea what they're doing there, but they are doing a lot. And we're scrambling as fast as we can, but these studies are really important.
Q One final question on Mayo B. Is there a peaking capacity being installed as part of the project; i.e., will it be able to peak in wintertime with the fluctuating water levels in the four-bay Wareham Lake such as is being done at Schwatka? You are allowed to say you don't know.

A MR. BOWMAN: It's actually a bit of a complicated question, but the plant is not being designed at this point to make peaking a priority by any stretch of the imagination. And the main reason is because by the time you hook Mayo into the WAF system, which is the premise that we talked about yesterday with respect to the project, it's a relatively small plant. Even Mayo B is a relatively small plant on a relatively big system.

So you are designing the plant and figuring out installed capacity to put into it and trying to figure out the best way to make sure you're getting winter energy. There was an additional cost to trying to put in a peaking capability. The actual output or the number of megawatts you might be able to get towards a peaking capability is relatively
low in relation to the overall system. And for some other technical reasons related to the intake, it's questionable whether you could actually try to use that plant on a peaking basis.

And it's matters that the engineers are working through, but it is far and away down the list of sort of minor considerations by comparison to trying to make sure that the energy that comes out of it is maximized through the winter.

A MR. OSLER: But we are in a general sense of all the things we've been talking about, we are trying to look at the issue as part of the project of making sure we can get the best long-term average energy from the plant that's now being developed, which includes issues of storage at Mayo Lake, and I'll just leave it at that.

But it's not that we are just looking at energy and consolidating facility. We are looking at licencing issues that would allow the plant to achieve for reasonable costs the best long-term average energy, which includes some storage issues, and
Mayo Lake's the only opportunity that exists.  
Wareham doesn't really do that.

MR. MAISSAN: That concludes my questions, Madam Chair. Thank you for your indulgence.

THE CHAIR: Thank you, Mr. Maissan.

15-minute break at this time.

(BRIEF ADJOURNMENT)

THE CHAIR: Thank you very much.

Mr. Landry, do you have some undertakings?

MR. LANDRY: I do. Thank you, Madam Chair.

The first one I would like to deal with is -- it will be dealt with ultimately by Mr. Osler, but it's going to require the entering of an exhibit, but it is in reference to an undertaking at page 262, line 11. And it relates to, I think it was called, I don't have the transcript in front of me, but the security agreement that Mr. Marriott that talking about yesterday.

So what I will do is -- I think the best thing to do is enter it as an
exhibit now. I have given it to Ms. Lemke and people in the room. So if we could make that document as the next exhibit, with I understand to be B-15.

THE CHAIR: So marked B-15.

Exhibit Number B-15:

Answer to undertaking given to Mr. Marriott re security agreement.

MR. LANDRY: And Mr. Osler will speak to that, and then we have a couple of other undertakings we can give to the other panel members.

THE CHAIR: Thank you.

MR. LANDRY: Mr. Osler?

MR. OSLER: Madam Chair, we were asked with respect to the flexible term note, which is in evidence. At paragraph 9 of that note, there is a reference to a security agreement mortgage, and could we find out what that was all about and what the current status of it was.

The document Exhibit B-15 is the mortgage that was registered pursuant to that paragraph 9 in the flexible term note to deal with the security with respect to that
note that the paragraph required.

The date of this document is 1993, so you can know that this was a registration that took place pursuant to the original transfer agreement when the note was still held by Canada. Yukon Development Corporation and Canada were the parties.

Since then this mortgage was in fact registered I'm told. Since then the flexible term note was purchased by Yukon Development Corporation from Canada, and at that time I'm told that this mortgage was assigned to the Yukon parties and away from Canada and has subsequently been registered in the land titles office.

MR. LANDRY: Mr. Bowman, I understand that you have a few undertakings that you can provide to the Board.

MR. BOWMAN: Yes. Thank you.

There are two that arise from today, so I'm -- of course I don't have the transcript references for where they arise, but one was in regards to your cross-examination of Mr. Maissan just earlier today after lunch, and it was in regards to
line numbers.

And the numbers in question were line number L355. That is the number that's given to the line through Haines Junction. L356, which is the line to Ross River. And the question was whether the Carmacks-Stewart transmission project has a line number, and it does. It is L173. I believe that addresses that one undertaking from Mr. Maissan.

We also had an undertaking from Mr. Buonaguro this morning in regards to the diesel contingency fund, and it was seeking some rather older documents that set out the rules around the fund and how it operates.

And in order to complete this set, it -- I'll make reference to five documents, three of which are -- I have copies, one copy here which we can give the Board, and we'll email them out to people. They're not short documents. They are not long, but they're not -- they're submissions made that were made to this Board. And two of which are Board orders, so I'm assuming those will speak
for themselves.

The diesel contingency fund arises from the negotiated settlement in the 1996-97 GRA. So the diesel -- the negotiated settlement document itself is not a part of a Board order. And so I have a copy of that, and that will be one of the documents that we will circulate, provide a copy to Ms. Lemke and circulate. And of course that led to the order that was ultimately finalized, the 1996-97 GRA.

The diesel contingency fund, as I noted at that time, was not fully detailed in terms of some of the operating rules and the like, and that was ultimately addressed by Board Order 1999-3, and that again would be an order from the year 1999.

It is not particularly detailed in terms of what it's -- what the order itself says. The order says it accepts the documents as filed by Yukon Energy. But it references two documents filed by Yukon Energy, one a document dated June the 6th, 1999, which was a report filed by Yukon Energy, and the second was a document of October 7th, 1999,
which was additional comments filed by Yukon Energy in response to submissions received by the Board.

So it's those two other documents, the June 6th, '99, and the October 7th, '99, that set out how the fund operates, and the Board ultimately made its decision on Order 1999-3.

So those two submissions from Yukon Energy again I have a paper copy I can give Ms. Lemke, and those will be circulated in a scanned version via email and, we can make paper copies for anyone who wants them on paper the same way as the further exhibits were dealt. It be easiest to do them by email given that the size adds up.

MR. LANDRY: Perhaps, Madam Chair, to help Ms. Lemke, I just took a note of the documents, we could mark the documents as an exhibit. We will get you the hard copies now. You can put them in that way. When they come electronically, we know what exhibit numbers they have.

So if we go in the order of the documents that were referred to by
Mr. Bowman, the first one would be the settlement agreement, and which exhibit number would that be, B-16?

THE CHAIR: B-16 so marked.

**Exhibit Number B-16:**

MR. LANDRY: The next one would be Board Order 1999-3, which would be B-17, Madam Chair?

THE CHAIR: B-17 so marked.

**Exhibit Number B-17:**
Board Order 1999-3.

MR. LANDRY: The next one would be the June 6th, '99, correspondence report, so that would be Exhibit B-18?

THE CHAIR: B-18 so marked.

**Exhibit Number B-18:**
June 6, 1999, correspondence report.

MR. LANDRY: And the last one that was referenced was an October 7th, '99, additional comments. Exhibit B-19, Madam Chair?
THE CHAIR: B-19 so marked.

Exhibit Number B-19:

October 7, 1999, additional comments.

A MR. BOWMAN: Thank you. And then there's two more undertakings we can deal with now.

Mr. Mollard?

A MR. MOLLARD: The first item I have is dealing with an undertaking from Mr. Buonaguro this morning. He was asking regarding some capital projects. We had provided some actual spending in 2008, and he -- that was lower than the forecast in the application.

We had one we had to go back and check on, and we discovered that there was an error in the response to the interrogatory. It was UCG-YEC-1-90. The table lists the actual spending for the Aishihik water licence renewal project at 118,325. That actually should read 165,764, which is approximately the budget that we quote in the application of 167,000, so I think that addresses the undertaking.

THE CHAIR: Thank you, Mr. Mollard.

A MR. MOLLARD: I also had one other
item, the request from Mr. Maissan regarding
the Minto diesels. I can confirm they are
1,800 RPM units, and the fuel efficiency is
3.7 kilowatt hours per litre.

THE CHAIR: Thank you, Mr. Mollard.

MR. LANDRY: Madam Chair, there will
be just on our count a number of undertakings
that will be outstanding presumably if we do
finish this evening, and maybe when we can --
before we break we can just set a date by which
we get the balance of the undertakings. And I
don't expect that it's going to take long, but
we can do that before we leave.

THE CHAIR: Certainly.

In that case, we will
proceed with the Board questions.

Ms. Bentivegna, are you
prepared to proceed?

MS. BENTIVEGNA: Yes. Thank you,
Madam Chair.

YEC PANEL QUESTIONED BY MS. BENTIVEGNA:

Q Good afternoon, panel.

First I want to refer you
to YUB-YEC-1-4(b), Attachment 2.

A MR. BOWMAN: I think we're there.
Q Thank you.

Now, based on that information in that attachment, it seems that YEC has paid InterGroup 3,189,000 for the years 2005 to 2008 inclusive. Now, do you believe that's correct, subject to check of course?

A MR. MOLLARD: Subject to check.

Q Thank you.

Now, of that total, 190,000 is classified as administrative. The remainder is capitalized. Now, the descriptions for the capital work implies items largely of a regulatory nature, so I'm wondering what kind of administrative services would InterGroup be providing to YEC?

A MR. MORRISON: I think Mr. Mollard will answer a little bit, but nonadministrative services are classed address administration?

A MR. MOLLARD: Yes.

A MR. MORRISON: In --

Q If you could explain.

A MR. MORRISON: Sorry. So not providing administrative services but services that were provided would be categorized within the administration category of expenses. And I
will see if my colleague Mr. Mollard can give you some details.

Q Thank you.

A MR. MOLLARD: I will just take a minute with the IR, please.

Okay. I think I can respond to this. I would classify the costs in the administration categories in two forms. On a regular basis, they would provide -- InterGroup would provide us with support for our regulatory filings, which is our annual filings due to the Board, running the regulatory model, making sure our results make sense. That would be one aspect.

The other aspect is support. What happens when we have a project such as a GRA filing, we have costs that are incurred that are included as the costs that we present to you and say, These are our actual costs for the GRA process. There's always follow-up work that comes out of Board orders, making sure that we're doing all our filings and making sure that we're complying with everything. I can't charge those
costs to the project because the project is closed, so I spend that -- I carry that charge on my administration budget. So it would be that sort of thing on administration.

Q All right. Thank you.

Now, would YEC seeing that amount, that 3,189,000 I referred to previously, would YEC and the Yukon as a whole be better served with in-house expertise if it were developed and the resources and experience retained in the Yukon rather than consulting using a consulting group?

A MR. MORRISON: You may find that this is strictly my opinion, but my opinion, I think, based on at least my experience over the years that I have been involved in these utilities, and A, being able to hire and maintain a core of regulated -- of regulatory staff is A, a challenge in not just here, but across the North.

The second issue from my perspective is that we're -- we have not -- we have gone through a period of having basically no regulatory experience in the sense of no experience before the regulator. For years we
were never in front of the regulator. And it seems that during the period that we have gone through, the period you talk about, as we mentioned earlier, we have been here four times or five times.

So, you know, having a full-time staff that has that capacity and that ability and that expertise would be, you know, in terms of workload would, you know, in my view kind of be kind up and down.

This -- we may go through this period -- and, yes, it's been very busy. We may go through a period where we're back to, you know, every two or three years we are in front of the regulator. So we've looked at from that point of view. Have we looked at it in terms of an absolute analysis of if we could get a staff? No, we haven't done that.

The other issue that I would have is that -- that most of the -- not most. Certainly a large number of the questions that have been answered have been provided or are -- we're able to answer them because of InterGroup's continuity over the years of they know the -- they have been
involved in these hearings even though we've
had different people sitting at this table from
the Utilities' point of view in terms of
utility staff. So they have been the one piece
of continuity that we have had.

So if we think good value
for the money, I think it's very good value.
And could we do it with internal staff? I
think it would be very, very difficult.

A MR. MOLLARD: I could also add
something to that. I have had the benefit of
working with another small Northern utility,
and that utility did actually have a regulatory
affairs group and still did rely quite heavily
on consulting advice, especially for the
processes that Mr. Morrison referred to.

Q And does YEC have any type of regulatory
capacity, any in-house or any staff that deal
with regulatory matters?

A MR. MORRISON: The only staff that we
have that we would classify that deal with
regulatory matters are our day-to-day
accounting staff. So they certainly provide
some of the input here, but it becomes very
onerous on a very small accounting staff when
we start looking at the amount of work that
goes into these rate filings.

Q Now, under the capitalized costs from
InterGroup from 2005 to 2008, again this is the
YUB-YEC-1-4, the revised attachment to, it
includes work on the 20-year resource plan, the
2005 revenue requirement, the CSTP Stage 1,
Minto PPA, and the 2008-2009 GRA.

And my first question is,

Why are these costs not applied to a regulatory
hearing account? Why is there no deferral
account? Why are these costs capitalized?

A MR. MOLLARD: Sorry, in our parlance,
those are what is charged to capital. That
includes deferral accounts. So those charges
where they reference to specifically, for
example, GRAs, those are ultimately charged to
deferral accounts. We only have two
categories. We have admin or capital, so the
defered costs include our regulatory accounts.

Just for clarity, the
CSTP is a capital project, so it would be
included in our fixed assets: property, plant,
and equipment.

Q Now, are you saying that when you want to use
the funds in the deferral account then you will
ask the Board to use those funds as any other
deferral account if we're talking regulatory
costs to recover the costs out of that and to
apply them against the costs that were actually
allowed by the Board?

A MR. MORRISON: Ms. Bentivegna,
Madam Chair, I think we just need a minute.

Q Sure.

A MR. MORRISON: I think we're getting the
terminology off track here.

Q Certainly. Go ahead.

A MR. MORRISON: Ms. Bentivegna, I think
we are having a debate around deferring costs
versus a deferral account, so could you maybe
help us a little bit here. Can you give us a
little assistance as to kind of what you are
looking for.

Q Certainly. Well, I mean, I can take you to
each of the costs that you've put in as these
capital costs that appear to refer to
regulatory matters or proceedings. So, for
example, and you can go to your Table 5.7.
That might be of assistance.

A MR. MORRISON: It's late in the day. I
don't think our brains are working very well.

THE CHAIR: Another reason for a computer, Mr. Morrison.

A MR. MORRISON: As usual, Madam Chair, I got your message the first time.

THE CHAIR: That's debatable.

A MR. MORRISON: I know. I know. I just thought I'd make my point.

I think we're there, Ms. Bentivegna, thank you.

Q MS. BENTIVEGNA: All right. So if you look at the bottom where it say "Rate case completed," so the first amount you'll see is GRA Phase I revenue review 800,000. And I understand this to be, and it was updated in your updated amounts to over a million, that this would be costs related to this GRA?

A MR. MORRISON: Correct.

A MR. MOLLARD: That's correct.

Q So now looking at that cost, would that be considered a deferral account item over which before the money was used in that deferral account there would be Board oversight?

A MR. MOLLARD: Well, we -- if I understand correctly, we would apply to the
Board with our actual costs of which the money we spent on InterGroup to assist in the process would come to the Board for their approval to be included in that account.

Q And I guess now I've meant it to a broader question as well. All the costs, for example, that are included in your application and the updated amounts of over a million for this GRA, you mean all those costs would come to the Board and would be determined and that's what would be reflected in a deferral account for hearing costs?

A MR. MOLLARD: Yes, that's correct.

Q All right.

Now, when you estimate the 800,000, or now the million and so, of such costs, are you estimating the costs of consultants and legal services to be at the scale of costs the Board's scale of cost rate, or are these the actual charges that you estimate will be charged to you?

A MR. MOLLARD: They are intended to reflect the Board's scale of costs.

Q All right. Thank you.
under that rate case on Table 5.7, I'm still there, it talks about YUB-2007-7 and 9 resource plan, 643,000. Now, again, is that -- was that a cost award since that's been completed, that proceeding, was that -- at that amount of 643,000, was that -- was there a cost claim, was there a cost award in that proceeding and this number reflects that?

A  MR. MOLLARD: I just need to check one thing there.

Q  Sure.

A  MR. MOLLARD: Mr. Bowman just provided me with a reference, under Tab 6, directives, Table 6.1, the costs of the -- at page 6-8, sorry, there is a listing of the resource plan costs, PPA costs, and Part 3 costs and the respective board orders in which those costs were approved.

Q  So just to confirm, those costs that are reflected here are the same as in the cost awarded by the Board and those pages that you are referring me to?

A  MR. MOLLARD: Yes, that is correct.

Q  Now, what about -- what is the -- I see reference to YUB-2007-8 Part 3 hearing. What
is that in reference to?

A MR. MORRISON: That --

Q Sorry. Go ahead.

A MR. MORRISON: Sorry, Madam Chair, that

is the Carmacks-Stewart transmission line

project energy certificate Part 3 hearing under

the --

Q And does the Tab 6 at page 6 -- sorry, 6-8 also

refer to the hearing costs on that?

A MR. MOLLARD: Yes, it does.

Q And they are the same as the 185?

A MR. MOLLARD: That's correct.

Q Now, I notice in your April 24th update, and

still on costs, and it refers to the GRA

application at page B-3 under "Administration,"

the third bullet, and it says (quoted as read):

"Regulatory Affairs .094 million

expenses to participate in YECL

hearing without seeking cost recover."

A MR. MOLLARD: Yes, I have that.

Q Now, why did you not seek cost recovery. And

what I mean by that is put in a cost claim, if

your intention was to put it in your hearing

reserve account. I assume that that's where

it's going?
A MR. MOLLARD: No, it is not in our hearing reserve account.

Q Okay.

So how are these costs different from the costs we have just spoken of?

A MR. MOLLARD: It wasn't our process, so we discussed it internally and decided that we would not put a claim in.

Q All right.

So how do you arrive, then, at the .094 million costs, and what do those reflect, and can we have a break down? Can you undertake to have a break down?

A MR. MORRISON: Madam Chair, we can certainly undertake to provide a breakdown. That would be the easiest.

Q Can you give me any indication of how that sum was arrived at?

A MR. MOLLARD: It was largely a cost associated with drafting IRs and reviewing IRs in participation of the hearing for legal counsel and consultants.

Q And again how are those costs different than the rate case?
MR. MOLLARD: These costs are charged to our operations and maintenance budgets. They are not deferred in any fashion.

Q And though there is a mechanism, can you clarify whether those costs are according to the scale of costs?

A MR. MOLLARD: Those are actual costs, so they are what we paid.

Q All right. And would you have recovered your actual costs had you put in a cost claim?

A MR. MOLLARD: Not all of, I believe, with respect to legal. The rate would have been above the Board-approved scale of costs, so that wouldn't have been approved in total.

Q Thank you.

Then I noticed as well, in that same bullet, that it says (quoted as read):

"Legal and other services related to the Minto PPA."

And that's .078 million.

Sorry. Do you see that? It's on the same page as that update. It's just under it.

A MR. MORRISON: Madam Chair, that's, just so that we're clear, and I want to make sure
that I'm clear as well on the question, but I think I am. The cost of .78 that we're talking about here is not for the Minto PPA GRA. It's not that proceeding. It's legal costs in drafting and dealing with the issues around the actual PPA document itself and dealing with Minto mine in '08 -- in 2008.

So it's not part of a regulatory -- that regulatory process.

Q Okay. That's fine. I just wanted to clarify.

Are there any other costs in your O&M that do not relate to regulatory proceedings, however are legal costs or other consulting costs other than what's listed in that 5.7?

A MR. MORRISON: Madam Chair, before my colleague Mr. Mollard answers that question, I just want to be clear, when we're talking about regulatory costs, we are talking about rate application costs?

Q That's what I want to clarify is what do you consider, because -- what do you consider rate-case costs and what do you consider regulatory costs?

A MR. MORRISON: Okay. And to me that's
important, because what I'm trying to make sure that we -- and I want to be careful. When we're talking about this proceeding or these types of proceeding or rate matters including the resource plan in the Part 3 hearing, we -- I just want to make sure that we give you an answer for that.

When you say "regulatory costs," I may have -- we may have costs related to getting a permit or something even just something entirely small operationally, but it may have a regulatory cost but not the same regulatory cost. So I'm just trying to be careful.

A MR. OSLER: And just we started with an exhibit on interim costs, and some of those costs have nothing to do with rate regulation at all or appearances before this Board. I don't know off the top of my head what portion, but a material portion deals with the other type of regulation, environmental, the filings for the two permits that have been filed for so far, one succeeded, the Carmacks-Stewart YESAB filing, and now the Minto -- the Mayo B YESAB filing, as well as a bunch of other stuff that
would not come to the Board but would be related to those projects.

Some of the -- the corporation does have regulatory staff. If you start using the word broader than we are using it at a moment, in the environmental and the permitting field, and Mr. Morrison can address that. But there may be some need to be very clear about what we're talking about.

A MR. MORRISON: So I just want to make sure I'm clear from Mr. Mollard when he is answering that question on that number, just to make sure that he's clear with you.

A MR. MOLLARD: Could you repeat the question. Sorry.

Q I wanted to know what -- how the service -- legal and other services related to the Minto PPA, how that .078 million was arrived at.

A MR. MORRISON: So the .78 related to the PPA.

A MR. OSLER: 078.

A MR. MORRISON: 078, sorry.

Is arrived at from legal costs that are related to the development, the
actual writing of the power purchase agreement.

A MR. OSLER: This is 2008 --

A MR. MORRISON: I'm sorry. Yeah. So this -- again, but it's to do with the agreement itself and costs related to working on that agreement and working with Minto on issues surrounding that agreement, but not in a regulatory proceeding is what I'm trying to get at.

Q Would it be very onerous for YEC to provide to the Board a breakout of costs, not rate case, but the regulatory costs that it has that you put under O&M for permits and matters related and other matters such as what we're talking about here?

A MR. MORRISON: For 2008-2009?

Q Yes.

A MR. MORRISON: Madam Chair, we're having a debate over here. If it's -- if it's O&M, I'm not -- we don't necessarily -- other than rate cases and major regulatory proceedings, like the YESAB process, we don't necessarily classify them as regulatory costs separate from, you know, general admin costs.

A MR. MOLLARD: I could perhaps give an
example. In my own department, within the finance group, I will have a consulting budget of, I'll say, 25,000. Now, I may spend 5,000 of that on InterGroup to assist me in my annual regulatory files as part of my normal O&M. I also may have occasion to hire an IT consultant to help with my financial information system or a local CA to help me if I need some help with a complicated accounting matter.

As a matter of practice, we don't differentiate at the budgeting stage what that 25,000 is going to be spent on. It's just budgeted as a bucket of dollars that the manager can draw on, or consulting dollars. I couldn't tell you what the split is, whether it's regulatory or IT or other matters. So that's sort of where we're struggling with the '08-'09.

A MR. MORRISON: I think probably, from my perspective, the more difficult pieces, we have a whole series of regulatory items that we deal with, and so let me use a couple of examples. And I'm just trying to think as I think through this of how difficult it might be to do what you are asking me to do, because if we could do
it, I would like to do it.

We do a series of regulatory matters that are related to our existing water licences, as an example. And we would consider those, in one sense, regulatory. And we also consider them from an O&M point of view as just admin costs. So -- or they may be capital, depending on what they are.

But what happen I'm getting at is, we have reports that we write. We have a hydrologist, an engineer, who actually spends part of his time probably doing regulatory work, but I'm not sure that we could pick all of that out of there very easily is what I'm saying.

And so those are more the kinds of examples and what Mr. Mollard was talking about. We have an environmental manager, and he does a whole series of regulatory things, including getting permits for things that we're doing on the Carmacks-Stewart line, which his time would be assigned to. But he also does diesel permits and, you know, environmental permits for things that we're doing or moving or small capital
projects. So picking it all out would -- may be very difficult. We could certainly have a very good look and see what we could give you, but I'm not certain it would be very easy to do.

THE CHAIR: Are you undertaking? I think the question was, was it too onerous.

A MR. MORRISON: We will look at that, if you don't mind.

Q MS. BENTIVEGNA: You can use your best efforts and see what --

A MR. MORRISON: See what we can do.

Q Exactly.

Leaving those costs, now going to YUB-1-3 (c) regarding the Alexco mine.

A MR. MORRISON: 1-3?

Q 1-3.

A MR. MORRISON: Thank you.

Q YUB-1-3?

A MR. MORRISON: Yes.

Q That's okay. I just didn't rattle off the whole chain.

A MR. MORRISON: I was listening to Mr. Maissan's explanation. I got the 1-3 as
13.

THE CHAIR: We should standardize this in the future.

Q MS. BENTIVEGNA: Sorry, are you there?

A MR. MORRISON: Yes, we are.

Q All right.

With the potential of the Alexco mine in 2010, are there any forecast regulatory costs in 2009 for this customer addition, including progression of the Carmacks-Stewart transmission project, Phase II.

A MR. OSLER: We are having one problem. The question seems to deal with the Carmacks Copper mine, and you are asking us about Alexco mine. So I want to be clear, before we start answering, which mine you are after.

Q It's the Alexco mine, and -- but also I'm referring to the progression of the Phase II of the Carmacks-Stewart transmission project.


Can you please repeat the question.
Q Certainly.

   With the potential of
   Alexco mine in 2010, are there any forecast
   regulatory costs in 2009 for this customer
   addition, and then consider the progression of
   Phase II for the Carmacks-Stewart transmission
   project.

A MR. MORRISON: We're not -- we do
understand your question this time.

Q Oh, good.

A MR. MORRISON: We're having a debate
about whether or not they are in regulatory
costs or not, and so . . .

Q I was hoping I was leaving the subject, because
this question again refers to regulatory costs.

A MR. MORRISON: You are in a way.

   Let me try to answer it
   this way: What we're doing in 2009 is
   negotiating a power purchase agreement with
   Alexco, with the view to them coming onto the
   system in 2010. We have some money in -- as I
   understand it, in that table that you
   previously related to, and it's $300,000, but
   it's offset by a customer contribution of
   $300,000.
So, basically, on the premise that if we are incurring some costs, they are going to have to cover the cost. So more like a spur line kind of a treatment than the main line of the Carmacks-Stewart project. Okay?

So we don't have anything other than that. I'm looking at these guys. They are not answering.

We don't have anything else other than that, so whether -- and we haven't got -- as a for instance, we haven't got funds in to do a major Carmacks-Stewart, you know, hearing or anything like that because we're just not sure on timing and where these things are going. So those would be things we'd bring at a later date.

MR. OSLER: There are budgets -- to the best of my knowledge, there are budgets that are referred to in Tab 5 for Stage 2, Carmacks-Stewart, as well as Alexco, I guess. And I think those are what you gentlemen are looking at when you look at the schedule.

Those costs in each instance, I think, are stated to be -- assumed
to be offset by customer contributions. But not Stage 2, in the case of the line.

Beyond that I don't think anybody has broken those costs down in the GRA purposes, as developed last year, into subheadings or anything else, that I'm aware of, particularly with respect to Alexco.

Alexco, there are some issues that may involve some transformers or other things that they would pay for as well, so there is a series of different things that have to be worked out that might be a part of the cost picture.

In terms of affecting the GRA, the bottom line was that Alexco certainly didn't affect it net, and I think Carmacks-Stewart Stage 2 is only in work in progress through the test years.

Q I guess just to follow up, does this potential of the Alexco mine enhance or promote the Phase II Carmacks-Stewart transmission project?

A MR. MORRISON: It provides the prospect for some near-term benefits if the line is developed fast enough and the loads of Alexco are what we are forecasting. But it is not
determinative of whether one would go forward
or not go forward with the line, for all of the
reasons we have talked about.

Q All right.

And can the load for the
mine be managed without construction of any new
facilities? I thought I heard you just say
something about a transformer or . . .

A MR. OSLER: Well, the mine --
Alexco's mine is essentially a mine and a mill
at different locations, and each has to be
connected into the existing system at Keno. It
would be very much the nature of a normal type
of connection situation where you have to
add -- you do have to increase for the mill.
You have to get a transformer and provide a
connection.

For the mine we are busy
examining exactly what it would be. It might
require some upgrades to a transformer.

So in that sense there
are some requirements that are being discussed
from the point of view of the customer paying
for them. But there is nothing like a spur
line or major development of the type we had
for either Minto or we would need for Carmacks Copper.

Q All right. Thank you. Now I would like to take you to YUB-YEC-1-12. It's regarding the Minto diesel business case.

A MR. OSLER: We are there.

Q Now, is YEC planning to continue refurbishing all the Mirrlees units?

A MR. MORRISON: Well, I think -- and Mr. Osler can jump in on this, he talked about it a little bit, I believe yesterday if not today. The part of the benefit of the Minto diesels is we can -- we can look at and delay timing on the Mirrlees units.

And the reason for refurbishing the Mirrlees and looking at the Minto diesel is to provide capacity, as we talked about. So they are there to provide the backup and the capacity on the system. So depending on the timing, whether or not we need to do Mirrlees in addition to Minto, whether we need to do Mirrlees two years from now and three years from now, is also going to depend on the load. But we would do them if we needed
additional capacity, that's for certain.

A MR. OSLER: The basic plan is still
to do them. The timing of the last one is the
major question mark, as discussed in the
application.

Q Now, are the Minto diesels and the Mirrlees,
based on the planning criteria N minus 1, are
they needed? Are they both needed?

A MR. MORRISON: I'm going to -- I think
while I'm going to let Mr. Osler, or perhaps
Mr. Bowman, add something to this, but I just
want to make sure that we're careful that when
you say needed, it's when they're needed is
important. So I'm going to -- based on that,
I'm going to let my colleagues jump in.

A MR. OSLER: We'll do it. I'm not
going to have my mind around the actual
numbers, so Mr. Bowman can check on that.

But the short answer is,
they are needed in the time periods that are
being discussed in the application, to the best
of our understanding. In the case of the
sequence with the Minto and the first two
Mirrlees units, it looks like they would be
needed in a pretty predictable time period.
And the actual timing of the third Mirrlees unit at Whitehorse -- sorry, the Faro unit plus the two units at Whitehorse, are fairly predictable in terms of their timing, it appears. But the fourth Mirrlees unit, the third one at Whitehorse, the timing is the one issue which we are retaining some flexibility around.

I understand that they meet the tests of the criteria when we say "needed."

Do we have any other numbers we could add?

A MR. BOWMAN: Probably the easiest thing to do in respect of numbers is refer you to page 5-10, which deals with the criteria, as you say. It references in respect to the N minus 1 criteria, which is the driving criteria on the system today, and it is the one on which there is basically no debate on how to apply it.

So that has left us with some comfort as to how the criteria is to be applied for at least this time period.

The peak that was
forecast, and as noted there, for the end of 2009 effectively said, if you did the Faro Mirrlees, as is underway, and you did the first of the Whitehorse Mirrlees, WD-3, as is also underway or basically done, by the time you got to the end of 2009, you would have a surplus of three megawatts, based on the forecast at that time, if you didn't have the Minto diesels.

That is a problem, first, because the peak this last winter was about 2 megawatts higher than had been forecast; second, because if you only have a surplus of 3 megawatts, you don't have an easy ability to take out of service a 5 megawatt unit and do the work that's needed on it. Because when you take it out of service, you are driving yourself into a deficit, or you bound yourself into having to do it over the course of the summer, when the capacity is not required, with no ability to have it take longer or run into any trouble.

So the Minto diesels have provided that cushion, that flexibility, that once the Faro Mirrlees is done and the Whitehorse Mirrlees is done and we head into
2010, and the loads grow at the level that we are expecting, the second of the Whitehorse Mirrlees can be taken off-line and be refurbished in 2010 and brought online, and there wouldn't be big risk about making sure that you absolutely have to have it done for the start of winter.

As we noted, that once that unit was brought back on, you would now have a small bit of cushion on the system, and the question is how quickly that cushion gets used up. And it could get used up by increases in peak load, which we continue to be surprised by, the extent to which Whitehorse's peak load is increasing, or it could be used up by addition of other loads, or by a loss of a unit, catastrophic failure, the type of things that can happen and that this whole criteria is designed to address.

And it gives you the flexibility to then decide, do we want to incur the costs on WD-1 at a half a million a megawatt to get it back in service, or can we defer those costs, having spent a half a million a megawatt on the Minto diesels, and
save the exact same amount of money. You are no further behind. So that's what the Minto diesels do. They are needed, and they are no more expensive, and they give flexibility in respect of the criteria, the N minus 1 criteria.

Q Now, if I can refer you to -- this question deals with the 20-year resource plan. During that proceeding you will remember, because I don't have a copy of the transcript, but that YEC committed before the Board that it was going to come before the Board for projects exceeding a $3 million threshold. In light of the Board's recommendations on that issue, has YEC reconsidered this commitment? And if you will remember, the recommendation was for projects exceeding 1 million.

A MR. MORRISON: I don't know why I get the hard questions at the end of the day. No, we haven't reconsidered it. And I guess, you know, the important part of that is trying to find a level. And let me say this: I'm probably already in trouble with the Board and the Chair about following -- following direction, but I
try to -- we try to do as best we can. With no
disrespect to the $1 million level, we spent a
lot of time on the $3 million level, trying to
find a way to get in here with large projects
where there was no requirement.

We would, I say to you
this -- maybe say it this way: we would be in
here -- a consideration is major projects that
aren't more operational in nature than in terms
of capital, and that's where we are trying to
find this balance. So what's the difference
between just a general -- we call "maintenance
capital," which is our general capital budget
that has projects in it that might be, you
know, overhauling the Whitehorse 4 hydro unit
on a -- which happens on a regular basis after
so many hours of operation, that project could
be a million dollars. Now, do I have to come
to the Board to overhaul a unit because it's
got to -- you know, it's houred out? I
don't -- I don't think that's what the Board
means either. And so we're trying to find that
balance.

We're happy to make --
we're happy to try to find a number. If it's
not 3 million, is it 1? Is it 2? We're -- I think we're -- our offer of coming before the Board for 3 million was an offer to make sure that we were getting in here with major capital projects and getting them reviewed by the Board prior to us building them. But it didn't generally relate, our thinking, to operational capital items. And that's where we tried to find the balance.

Now, you know, we certainly are happy to have a discussion with the Board about that and see if we can find some definition around what it is the Board is thinking versus what we're trying to do. I don't think we have built anything in addition to what we have said that's over a million since then. I can't -- I can't think of anything where we've not come back to the Board with a project that's a million or more since that plan.

Have we rethought about it? We have. We've struggled with it. As I say, what is it that the Board is looking for us to do. And certainly we would be happy to -- and I think that was my commitment, was
major capital projects, we're happy to come into the Board, because I think it's a -- I think it's a wiser process, from our perspective, because it gives us a review of those projects and an erring of whether or not the Board looks at them in a positive light prior to us building them and then coming back and arguing the need for the project and the money.

So I think that's where we're at. You know, we haven't -- as I say, we haven't not followed the order, because we haven't built anything over a million that we haven't brought here, but we are having that struggle between how we get from our number to the Board's number and deal with those kinds of operational issues.

And Mr. Osler, I think, has a point he wants to make.

A MR. OSLER: In order for the company to be able to exercise what it's trying to do, it has to rely on the government to also provide the order in council framework for appearing before the Board, either through the type of thing we had on the resource plan,
which was setting for a hearing, or through the energy certificate route, which the government used on the Carmacks-Stewart.

And there is a series of parallel conversations and questions going on about the Minister's letter to the Board in the summer of '06, saying that the government is committed on major energy projects. And I don't know what -- I don't have the wording in front of me, to require in the future energy to be order in council declared as energy projects that would require us to come before the Board.

So in the overall context, the one comment I think we should make is we would like to find an overall framework in all of these things that would work and achieve the objectives we are talking about, however that's done. Because it requires the government, not just us, and anything we can do to facilitate that, so that there is a clear set of rules and we can all plan with.

The intent is, I think, clear, and the problem is how to execute it. And whether it's 1 million or 3 million or whether it's some other type of wording as to
what a major project is that gets around from
the dollar limits, we're all open to discuss
and find the vehicle that works.

Q Thank you.

Now, if I can take you to

YUB-YEC-1-15.

A MR. MORRISON: I think we're there,
Ms. Bentivegna.

Q Thank you.

Now, for YEC's 2005
required revenues and related matters
application, YEC applied for and received
approval to have its ROE based on the BCUC
benchmark for a low-risk utility. The Board in
Order 2009-2 directed YECL to use a similar
approach in its 2008-2009 GRA compliance
filing. YEC, for its 2008-2009 GRA, has
applied for the same approach in determining
its return on common equity.

Now, in response to
Part (b) of that question, YEC responded that
Board Order 2005-12 did not necessarily impose
a precedent in the Yukon for the determination
of return on equity. Given the direction in
Order 2009-2 in YEC's current request before
this Board, is YEC satisfied that such a precedent exists for the setting of the ROE on the BCUC formula or benchmark?

A MR. OSLER: Yukon Energy would be happy if that was the Board's conclusion, that this is the process.

    We know that in 2005 everybody around the table said this isn't a precedent, so that's not the issue. But now that the Board has made a determination for both utilities using the same approach, it would be good, from our point of view, if that was viewed as precedential so that we can all rely on that going forward as a simple method.

    It doesn't necessarily involve all of the things that happened in British Columbia flowing from that determination. But it just simply means when we come for a GRA, we all know how we're going to determine an ROE for that GRA purposes at the moment. That's a baby step.

    So if it is viewed as a precedent, Yukon Energy, as far as I'm advised, has no problem with it.

Q Thank you.
Now, is YEC requesting the Board use 8.47 percent based on the BCUC Letter L55-08 to determine YEC's ROE for 2009?

A MR. BOWMAN: The simple answer is yes.

It's addressed in Exhibit B-10, page A-1 to A-2. The update that Yukon Energy filed reran the numbers for Tab 7, recalculated the revenue requirement, as was stated in the opening statement, and it's based now on an ROE of 8.47, which was the 2009 number that we calculated based on the BCUC letter for that year. And I note it is November 20th, BCUC Letter L55-08. I didn't catch if that was the same number you used, but Letter L55-08.

I apologize. Hang on one moment. I was referencing the wrong number. 8.47 is what the letter sets out for a low-risk utility. Yukon Energy's process for '08, the same it's proposing for '09, and the same it used in '05 would be -- have to adjust that for two items: One is that Yukon Energy, similar to any of the utilities, has an adder for not being the benchmark low-risk utility, and separately has an item subtracted from its ROE.
pursuant to the order in council, which
requires it to be lowered by one half percent.
So the end result is not 8.47, it is 8.49, and
it is in the same paragraph. It is at the end
of the paragraph.

Q Thank you.

Now, if I can take you to
YUB-YEC-1-27, part (c) of that question.

A MR. MORRISON: We are there,
Ms. Bentivegna, sorry.

Q All right. Now, in that part (c) it states
(quoted):
"The development of an Independent
Power Producer's policy is being
addressed by the Yukon Government as
part of the recently released 'Energy
Strategy for Yukon.'"

What has YEC's role been
in that process?

A MR. MORRISON: We haven't had any role
yet in that process. I don't know whether we
will have or not. But we understand there is a
process.

I would like to add
something to the issue, if it's helpful. We
don't have a -- I get asked this question quite often, you know, What's Yukon Energy's independent -- do we have an IPP policy. And the good news is we don't. The good news is that we don't have anything that says we can't do -- we can't entertain proposals from IPPs, and there's no rules around that you have to do this or you have to do that.

To me what that tells us is we can certainly entertain submissions or proposals from IPPs, and we would happily do that. We would happily -- be more than happy to sit down and chat with someone if they have an independent power producer proposal of any kind, and we've never had any in all the time I have been here. And we have had people come in and ask us, Is -- you know, do you have a restriction? Because they seem to think that there is a restriction. Do you have any restrictions about independent power producers hooking up to the grid? And we tell them absolutely not. If you have got a proposal and you would like to bring it to us, we would be happy to.

And particular today. To
be -- you know, to be kind of very clear,
several years ago we did have a discussion with
a group that said they were going to do -- they
had a proposal to do a project, and I said to
them, You know, we would be very happy to talk
to you, but please consider this -- and this
was five or six years ago: we have a surplus in
hydro, and, you know, you need to consider at
what price we can duplicate hydro production.
So if you were looking at timing-wise, we would
be glad to talk to you, bring your project
forward, but right now we're probably not going
to buy it if you are telling me that you are
going to have something to connect to the grid
today.

That's a very different
story, and that was several years ago. Today
if we had somebody come along and say they had
an independent power producer policy, and that
wasn't, in my mind, just to be clear, turning
on a diesel somewhere, because we can do that,
we'd be very happy to entertain them, just
based on the load forecasts that we're looking
at and the need to get all of those Mayo B and
Atlin and Granite [sic] and everything else
onto the system. If somebody else has got a
good idea, you know, there is nothing to stop
them from coming to us, and there is nothing to
stop us from entertaining.

Even without a policy, I
say we have one: we would be able to talk to
people.

Q Do I take from your answer that YEC hasn't at
this point undertaken any demand-side
management initiatives?

A Mr. Morrison: You would be correct,
yes. Yes.

Q Thank you.

Now, if I could take you
to YUB-YEC-1-40.

A Mr. Morrison: We are there.

Q Now, it states in that IR that (quoted):

"At the September 2007 Board of
Directors meeting, this estimate had
increased to $8.8 million. This
amount was based on tendered cost for
most major components (excluding
substations). The construction
decision was based on this figure, not
$3.83 million. Updated economics
assessments confirmed that even with
the final cost number, the project
still yields Minto material cost
savings over its life."

Now, are all the costs
for the Minto spur paid by Minto?
A MR. MORRISON: That's correct.
Q Thank you.
Now if I can refer you,
this one is CW to YEC-1-23 (a).
A MR. MORRISON: Could you repeat the
number again, please.
Q Sure.
1-23 (a).
A MR. MORRISON: We are there.
Q Now, in that response you refer to (quoted):

"Professional development is a
contractual obligation related to
employment. The budget was used in
2005, but no activities occurred in
2006 and only limited professional
development was taken in 2007. The
2008 and 2009 budgets include the
expense as a required component of
Yukon Energy's costs."
So my question is, What do you mean by "contractual obligations"? What type of professional development is part of a contractual obligation?

A MR. MORRISON: It -- Madam Chair, we were talking about my contract, and it's part of a -- it's in my contracted that I'm provided -- or I have an allowance for professional development training every year, and it's $15,00, and it's in here. Some years I have used it and some years I haven't.

Q That leads to my next question. Is there any assurance that the expenses will be incurred over the test years?

A MR. MORRISON: Well, to the best of my ability, I would answer that question yes. The only reason it isn't used is that I just, you know, find myself without the time to do it. And I keep getting chastised for that, but some years it's just busy. But there are plans to use it, and that's why it's there, yes.

Q Now, I want to take you to the energy project certificate for the Carmacks-Stewart transmission project Stage 1. And I did give your counsel some aids to cross so that you
have the numbers as to what was in that application.

Now, page 1 of the application for the energy certificate describes Stage 1 of the CSTP as approximately 98 kilometres of 138 kilovolt line and substations at Carmacks, Minto spur, and Pelly Crossing. Schedule 1 of that application shows the high-end costs for the project to be 25.9 million.

Now, at what point in time did YEC approach this Board for its recommendation to proceed with the project. And what I mean by that, was it at the preliminary stage or had final engineering, had it been substantially completed?

A MR. OSLER: So, essentially, as I think I said earlier, the resource plan numbers and the numbers that were used in the energy project certificate in Schedule 1, because these were the same numbers as has been used in the resource plan, just calculated to 2007 dollars and in-service dollars, those numbers were developed, obviously, by the fall, I think, of 2006, when we made an update filing.
during the resource plan in November, I believe, of 2006.

They did not include preliminary, let alone final, engineering. They were estimates that had been initially developed based on information the company had. And the company's senior people visited with some engineering firms and potential people that could be involved in the design of the plan, of the development I believe in the fall of '06, and they updated the estimates at that time, and we filed an exhibit with the Board in early November that effectively reflected those new -- any new information we had in that regard at that time, and those became the numbers that we used for the resource plan hearing. And they were the same numbers that were effectively incorporated into Schedule 1 of the certificate application.

Q So then how are those numbers developed if it wasn't even with preliminary engineering? I mean, you mentioned that there was, I think you said, visiting, some people were sitting down with some people, but how can the Board rely on numbers that are in an application as to what
costs a project might be if the underlying or underpinning for those costs isn't established?

A MR. MORRISON: Well, let me talk about that for a little bit. We were -- when we came before the Board with the resource plan application and this energy certificate application, we were -- we were -- we did not allude to the veracity of these numbers being any more than what we just talked about. We were very clear that we didn't have anything more than very preliminary numbers here.

And I seem to recall a debate that we were having about whether or not we were prepared to provide certain amounts of tendering information or budgeting information, which we weren't, because we didn't want to get numbers being driven up.

We engaged some of our internal engineering staff along with external engineers to give us preliminary estimates on these costs, and that's what we brought forward were these preliminary estimates. We didn't make them up. You know, we had some engineering expertise that went out and looked at, you know, pricing, current, you know, jobs
of similar size, you know, length, wires, and substations.

But by the time we got to building these things, we were in the middle of a very heated economy that had prices going out of sight. We always committed to the Board, and to everyone else, including our own Board, and our own Board held us to those terms, is that we would not go forward on this project without tendered information. So as concrete a number as we could get.

So not just preliminary engineering and somebody doing an estimate, not final engineering and somebody doing an estimate, actual tendered costs. So we tendered the line construction, and we brought that back. And so we had -- we had what we thought were very -- you know, 80 percent certainty that our numbers were pretty good.

We still didn't get the -- I guess, the grace of an economy that, you know, kind of went along for a period of time and we were able to keep those numbers. There was a lot of inflation, a lot of prices being driven up.
But when we went forward with the project, we did not go forward except and until we had tendered numbers. And the number that we got Board approval for was $8.8 million for the spur line, not 3.8. Now, 3.8 was what we entered into discussions with Minto with, and we told them it was very preliminary numbers, and they wanted to go ahead. We have never had them tell us stop; we don't want to do this. And we have been very, very clear. Minto, during the process of the construction of this line, got a monthly report from us, and that monthly report was comprehensive, where we were at, what was being done, what the costs were. We have -- they have been informed all along as to where this project went.

And all I can say to you is that, you know, if you have years and years and years of advance time, we could go out and we could do preliminary estimates and final estimates and tender and get all the numbers and then come in and see if we could get permission to build something, but that generally hasn't been the case. We don't have
those kinds of time lines. We built this
project, brought it forward. We're happy to
be -- to be scrutinized on our costs, but we
are very clear about what the costs were and
when we got them and what certainty we have
around those numbers.

Q Now, with respect again still talking about the
Carmacks-Stewart transmission project.

A MR. MORRISON: Yes.

Q We understand from the filing that the
connection to Pelly Bay Crossing from
Carmacks --

A MR. MORRISON: Yes.

Q -- was to be 138 kV transmission line and
138 substation, kV substation, be constructed
at Pelly Crossing.

A MR. MORRISON: Right.

Q Just to clarify, did I understand correctly
yesterday that you indicated that
Pelly Crossing is currently connected by a line
built to 138 kV transmission specification but
it's energized only at 25 kV voltage?

A MR. MORRISON: That's correct. The
line -- the line to Pelly Crossing is the
138-kV line, and it's just energized at a lower
level because to step it down at Pelly, it's a lot easier to be energized at 25 than it is at 138.

Q And does the decision to energize it at 25 kilovolt imply higher line losses for that segment?

A MR. MORRISON: I'd have to get back to you on that.

Q Certainly.

A MR. MORRISON: The decision to energize it at 25 is a decision -- is a practical decision of we can't -- if we're -- you could look at the project. You could look at the hookup at Pelly different ways.

We think of the project as continuing on to -- from Pelly to Stewart Crossing. So there's no point at this time of doing something different than continuing the 138 kV line from Minto Landing to Pelly. If we -- if we wanted to energize it all the way to Pelly at 138, we would have had to put in a more expensive either substation or a more expensive transformer to step it down to the small voltage that the community needs.

So it's -- I would say
that it would be cheaper to have higher line
losses, if in fact we have them, and I don't
know that, than to put in the equipment at
Pelly that we would have to do to stop the
higher line -- you know, to offset is all I am
saying.

Q If you could undertake to let us know.
A MR. MORRISON: I can do that.
Q Thank you.

Now, how -- approximately
how much of the total expense incurred for this
project was capitalized from the generation
feasibility budgets in prior years?
A MR. OSLER: There is a lot of
different questions going on here about how you
would define, in a practical sense, what you
just asked.

There wasn't extensive
feasibility study work done, from an
engineering point of view, until engineers were
engaged specifically on the project, and they
were engaged in March of '07. So they really
were all part of the last stage of the
project's thrust.

The earlier costs that
were incurred that would be capitalized were
costs relating to getting the YESAB permitting
and appearances before the Board relating to
the PPA, which is a PPA-related cost, and then
I guess the certificate exercise started in
late March, early April of '07.

So how much of the costs
of the main line are planning costs? I'm told
at construction approval they were 2.3 million,
2.4 million, and the final costs that were
planning costs were 2.5 million. And we --
those are all available in LE-46 for the main
line and LE-47 for the Minto spur.

So the breakdowns -- and
we actually put together a table for our own
sanity, and we would be happy to share it with
everybody, that sort of has the spur line, the
main line, and totals broken down with the
different information that the -- information
brought to the Board in the hearing that we
just referred to, the decision of the board of
directors, and the final costs, and also the
contributions.

But if you wanted to get
down to sort of how much is planning costs, you
have to go to the LE-46 and LE-47. It will
tell you how much was at each stage. So what
portion of those planning costs is really what
your question is getting at, and we need
clarity that -- they are all in the final --
there wasn't much spent before we were into the
home stretch in 2007 is what I'm sort of
suggesting.

It's a bit different when
we're doing Mayo B, but it was much more
engineering reporting early on.

Q You just offered to file the table?
A MR. OSLER: I would be happy to right
now if you want.

Q Certainly. If you have it, we'll take it.
A MR. OSLER: It helps us keep it
clear, so . . .

THE CHAIR: We have B-20. B-20 is so
marked.

Exhibit Number B-20:
Stage I Carmacks-Stewart/Minto Spur
Transmission Projects Initial Cost
Estimates, Construction Budgets, and
Final Costs ($million).

Q MS. BENTIVEGNA: Now, because of the scope
changes in the Carmacks-Stewart Transmission Stage 1, is it fair to compare actual costs to forecast costs in the energy certificate application for this project?

A MR. OSLER: I take it you're referring to all of the scope changes we're talking about. And then there would be the ones that we have highlighted and that have increased the costs, the requirements for a different route in one portion of the line and things like that.

Q And changes to the substation and --

A MR. OSLER: And the other type of changes were changes to the substation, particularly the one at Pelly, because that was part of the main line. And in that sense if you were doing a full, you know, apples-to-apples comparison, you have to take account of those changes.

The estimate in the original budget for substations for the main line was 1.9 million I gather from LE-46. The preliminary engineering which would have reflected the changes in scope reduced that to 1.65 million by the time the board of directors
made a decision in the fall of '07.

I can't tell you from this information how much the preliminary engineering would have estimated the change due to the change in the substations. I can only tell you that type of information from what's here. It probably -- the difference between the two probably understates the degree to which the substation change at Pelly reduced the cost.

Neither one of those two estimates, the original estimate or the construction approval estimate, includes provision for the changes that came from the YESAB process. I could tell you that much, which is the other type of scope.

I don't think the Carmacks substation changes were all that material, but I can't tell you anything about that from this -- you know, Carmacks versus Pelly. I would -- I would assume from my information that the big changes in substation scoping related to the Pelly Crossing substation.

Q Thank you.
Now, I know there has been a lot of talk about Rider F, but I still have a few questions of clarification. Now, is fuel price the only trigger to Rider F?

A  MR. OSLER: I'm sorry?

Q  Oh, Rider F.

A  MR. OSLER: Yes. What was --

Q  Is fuel price the only trigger?

A  MR. OSLER: Trigger?

Q  Or are there other triggers that will trigger the Rider F coming into play when there's a collection or a refund?

A  MR. BOWMAN: Well, the Rider F is the means by which ratepayers are charged or credited amounts that are in the deferred fuel price account for the two companies. So the changes in the Rider F or updates to the level of Rider F, implementation of the rider were at zero today, if it were to change, the trigger is in fact effectively the balance in the account and where the companies see it going. When they implement a change to Rider F, it's based on the two companies getting together, saying the balance is not tracking, you know, within a range that
people are satisfied with, and over the next 12 months, we see it going in a direction that will not keep the account at a low balance, so we'll implement a rider to aim to bring us back to zero within 12 months.

So, in fact, the trigger is effectively the balance in the account, if you'd like. Now, of course one level deeper, the balance in the account arises because of transactions that the utilities make with their respective fuel price accounts. In the case of Yukon Electrical, that's solely related to fuel price. In the case of Yukon Energy, it's related to both fuel price that -- for fuel that's consumed and variations in the secondary sales rate as was approved by this Board in '05, so it's actually those two factors.

A MR. OSLER: Can I just make one addition in the history sense. There is an odd thing in Yukon -- the order in council's -- going way back in the order in council in 95-90. Clause 8 requires that a fuel price adjustment be put there, so that's why we don't come to the Board for approval of each one of these.
Secondly, the Board in one of its orders in the early '90s chastised the two utilities for being tardy and letting a balance build up and not moving quickly, so the companies since then have said, Okay. And what Mr. Bowman is saying flows from that. Don't let the balance build up. Don't get -- don't be tardy in dealing with it.

Q So there isn't any set balance before you actually make the, adjustment whether it's up or down, so collection or refund? So there's no upper and lower limits?

A MR. OSLER: That is correct.

A MR. MOLLARD: As a matter of practice, we try to keep, I believe, a balance of plus or minus 200,000 in the account.

A MR. OSLER: But that's a practice, not a --

A MR. MOLLARD: That is practice. That is not an approved policy in any respect.

Q That's what my next question was, if there was either an administrative or operational policy for Rider F, and I believe you just said there isn't --

A MR. MOLLARD: There is not.
Q -- this business practice?

Thank you.

Now, with respect to Rider J, in your next rate application, would you be applying to eliminate Rider J?

A MR. OSLER: Madam Chairman, we assume that the process that -- of discussion with YECL will include looking at rate matters that would allow the riders to be removed and normal, proper rates put in place.

If that -- if that discussion and that consultation process leads to a proposal to the Board and the Board accepts it, what you are talking about might happen before the next rate applications. You know, it would be a process following from what -- this discussion process.

But I can't -- the utility cannot -- YEC cannot predict beyond that. I mean it's -- it needs some overall discussion and framework in order to remove it, and it would require rate matters to be approached in order to remove it, and it probably should be considered as a joint discussion with the two utilities and not just
a matter for YEC to change on its own, in an
ideal world anyway. So that's about as
responsive as we can be, I think, at the
moment.

Q All right. Thank you.

Now, this morning you
provided the annual reports of the key
performance measures, and I wondered if YEC has
an internal key performance measures other than
those that are set out in the annual report?

A MR. MORRISON: We have a recently --
we've had a couple of different attempts at
this over the last few years. We are in the
process of developing a KPI report that we are
working through with our board. It's in the
pretty early stages, I would say even draft.
We gave the first one to our board as a draft
at the last board meeting, which was a month
ago.

I'm waiting for the next
question which is can I give it to.

Q Well, since you asked the question, can you
answer it now.

A MR. MORRISON: Since I asked the
question. When's the other shoe going to drop.
We can -- I don't have a copy of it with me. My only caution is it's still kind of under development, but I guess we can look at trying to do that on a -- do you just want a copy of the one we have or is it something you want with -- on a regular basis? I guess that's my question.

Q Well, at this point --
A MR. MORRISON: We'll give you the one we have.
Q Yes.
THE CHAIR: You are going to give us everything. This is the time to ask. We just have our Board questions now.
A MR. MORRISON: So we'll get you a copy.
Q MS. BENTIVEGNA: Thank you.

Now, in your opening statement at page 7, you refer to the -- that YEC will meet with YECL regarding a Phase II application, and I wondered when YEC expects that a joint Phase II application might be filed?
A MR. MORRISON: Yikes. Well, I guess, you know, to be fair, we're going to have to sit down with YECL to see, you know, what
they've got, how long it's going to take us to put our information together. I'd hate to get out on a limb with an estimate that I can't stay to. So I'm just not exactly sure. We'll certainly do it as soon as we can. I can make that commitment.

A MR. OSPER: One of the things we have assumed is that I think it was -- in the statement is that the Board's order on our application would give the framework for both utilities to know what the revenue requirement is that the cost of service should be based on. So I assume that when the parties meet that they will probably endorse that idea and therefore the timing will be contingent to some extent on that.

In the past, utilities have said in the letters to the Board that they thought it would take three months when they had the information to prepare a cost of service. I don't know whether that's still feasible, but that's at least in a matter of record. And there's a lot of other matters that people think we should discuss in consultations. So I think the utilities will
have to meet and discuss that and, you know, maybe inform the Board of what they think -- what the game plan is, what they propose as a work plan. And I think that was implied in the letter if not in the opening statement and then inform the board and other parties how they propose to proceed. And if there's any other directions anybody wants to give them, then they have time to give it to them.

Q All right. So from your experience you can't give us -- thinking that the last time there was a cost-of-service study was 1992, but you don't have any indication, any parameters at all as to what you are working for or aiming for?

A MR. OSLER: The last time we had a big cost-of-service hearing was '92, but the last time we did one together was the '96-'97 GRA, and we did them fairly expeditiously in those days. And we had been working together, you know, for nine or ten years, and we also had resolved the big policy issues in front of the Board in '92. So we were very focused in those days on the issue of the focal point was getting the cost of services required for the
major customer Faro mine so that when the contract ended in that mine there would be a basis for the Board to enforce or to approve a rate that at least met the cost-of-service requirement of the order in council.

I think the issues that both companies would face right now is that I guess I'm probably the only person around who was there at that time, so -- and I didn't do the computing work. So we have to sit down and go through all the issues, and it may take more time than would be normally the case. And I'm assuming that's why three months was the type of parameter that was put forward.

So the best we have is what you have in front of you at the moment, and we have to have some meetings and discussions that would allow us to give you something better.

Q Can you provide any indication -- again, in the opening statement it talks about that the discussions will have to include rate design changes and based on current relevant order in council directives and as well as planning for future rate designs once the order in council
expires in 2012.

Can you give us any indication of the type of rate design issues and options that YEC intends to bring to the table.

A MR. OSLER: At a high level, yes.

Q Yes.

A MR. OSLER: The one that we have been emphasizing in this application is the runout rate issues which this application does not purport to resolve for the general service class or resolve in terms of a long-term approach beyond in dealing with what's been -- the requirements in the past.

In dealing with the general service class, the fundamental issue is that most of the sales are in the second block. The Board has the -- in our application we have that type of information in tables, which have been provided in Tab 4. 4.9, Table 4.9, provides the volumes by class, and you can see in there what percentage of the general service class is in the second block. And I believe it's, you know, upwards of over 70 percent.

When you have that high a
percentage of sales in the second block, the
ability to increase the runout rate and still
not have the whole class have problems, you
have to reduce something else if you are going
to increase the runout rate.

If we were to increase
the runout rate by the same number, 5.61 cents
that we proposed for the residential class,
there would be no first block rate. We'd have
to reduce the demand rate or do something else.
It's that big of a swing.

So we think that we will
have to sit down and discuss more rate blocks
for the general service class to make this
work. That's not an easy issue to discuss
quickly, but it's not surprising. We have seen
it in other jurisdictions. So that's a big
issue that we flagged in this application, and
we would intend to be discussing it. It's not
really cost of service related. It's very much
rate design related.

The Rider J issues that
UCG has asked us questions about, you know, how
do we get rid of those riders and deal with
them in the basic rates given the constraints
of the Order in Council 2008-149 where we have
to keep each customer class with no difference
in its overall revenues that are collected from
it, that problem the utilities faced together
in the early '90s when the same constraint was
there.

It didn't stop us from
second block rate changes and it didn't stop us
from other developments at the time. But the
issues today given the lag of ten years are
much -- appear to be much bigger, and the gap
between where the rates were at and the diesel
costs are much bigger, so that's a big
challenge.

Those are probably the
two biggies from Yukon Energy's point of view,
as well as trying to finds ways to do all of
this without having to have three separate
hearings in the future. I think we flagged
that issue too because of the concern about
regulatory costs and other things. So we were
trying to see if we can get back to where we
used to be where these things got handled from
an overall public interest point of view more
efficiently.
Q   Great. Thank you.
A   MR. OSLER: I can add one more thing for the transcript that we also will deal with wholesale rates, which Mr. Keough questioned us about. Just it slipped my mind as a topic, but I'm sure it will get discussed.

Q   Now, there was a discussion that occurred with Mr. Maissan on the need for the Mayo B, the Atlin-Gladstone and other hydro projects. Can YEC undertake to provide a table indicating YEC's estimate of when the hydro project is required, project timelines, including regulatory process, estimates of cost of the project, the energy output of the project, and the expected external load driving the project. And that would be for each project that we would ask that each of those be indicated.
A   MR. MORRISON: My answer generally is going to be no.

Q   All right. Can you explain.
A   MR. MORRISON: Well, it's the first time I've said no.

THE CHAIR: Are you saying it's not relevant?
A   MR. MORRISON: No. I just -- all of
those things I can't do. We are -- we are not at a stage with those projects where I can provide all of that to you at this point in time. At some point in time I can provide all of that to you, and if the undertaking is to do it sometime at a date in the future, I'm happy to do that.

What we can tell you is we could certainly give you, you know, a basic outline of the project as we think it's there, but I think we may have done that.

As I mentioned earlier, we are just in the process of engaging some consultants for a number of those projects. We don't have project costs of -- you know, in any kind of a format that would be -- I would want to rely on. We technically understand, you know, what we're trying to do with the projects.

I don't have a timeline other than we can tell you when we need them. We can certainly undertake to do that in terms of our forecast when we need those gigawatt hours, and I would be happy to do that.

A MR. OSLER: The biggest problem we
have in answering you is that they are project specific. The discussions that had taken place so far aside from Mayo B or Carmacks-Stewart have been as a package of projects to deal with a specific set of requirements.

So we tried in the answers to questions to give you most of that information and we could consolidate it like we did with B-20 and maybe add a few bits more information that is readily available at the moment. I think Mr. Morrison commented on the requirements side. I think we can give you a clean simple description of the load requirements as we see them emerging in some of the risks over the period we are talking about to 2015. We could probably -- we have put on the record the timelines with Carmacks-Stewart and Mayo B so we can just reiterate what we have said to you. The other projects are the ones where we don't have project-specific time lines or things. We have endeavours to try and get them done as soon as possible.

We could probably -- I don't think there is anywhere in this transcript that says what the generic levelized
costs are that we have assumed for Gladstone or Atlin or things like that. We could probably tell you that which would help explain. They are in the resource plan initially, but I don't know if we updated them or just relying on the resource plan. We can pull that together so everybody doesn't have to go all over the place looking for it.

Q That would be useful.

As well can you indicate what the external load driving each project so that what would be the -- what would indicate to you so that you can plan the timing? What point is the load going to the need, the external load then and relate it to the particular project? So what will trigger all the different -- for example, the -- a mine load.

A MR. MORRISON: Yeah.

Q Would that then trigger one of these, so that type of information?

A MR. OSLER: I will give you this much on the transcript right now, because it's fairly simple. Mayo B project, Carmacks-Stewart project if the funding is
available are needed in the time period of what
we're trying to deal with, 2011, fall of 2011,
early 2012 without Carmacks Copper being
committed, they will both be of value -- they
will be of value to a system looking at the
values emerging to 2012 with the Faro
reclamation and things like that. With
Carmacks Copper if it comes on the system in
that type of time period or the next year it
adds 40 gigawatt hours. So you can figure out
from there why they say we need Gladstone, we
need these other projects available.

It's a very major leap if
you add Carmacks Copper to the picture. And
that is something we are told we have to plan
for. Beyond that, the load is growing at
about, you know, 6, 7 gigawatt hours a year on
the main system. So it ended up with us saying
without any development at all before 2015,
without any new resources being put in place at
all on the Aishihik third turbine, we seem to
need 50 to 100 gigawatt hours of load. So it's
not so much the triggering of one project of
the other project. You might say they are very
valuable core projects, and where do we get the
rest, because people are worried that if we
develop problems in the project we still end up
with a fair amount of diesel. And that's why
they are looking at geothermal, and that's why
they are looking at other longer term projects
to be able by -- as soon as possible be ready
for those types of things.

But we're just looking at
Alexco and Carmacks Copper as big triggers, and
Alexco is already on the way to commitment.
Carmacks Copper is such a big lump that it --
if it comes along, I don't think we can meet it
in renewable resources at least in the initial
years. We will be running diesels. Is that --

A Mr. Morrison: Yeah, I think that's
fair.

This is the real trick in
terms of our planning as I was talking about
earlier is, you know, how do we get the right
amount of surplus on the system or coming onto
the system at the same time loads are coming
on. And this system is so small, that's really
difficult to do. It's really difficult to say,
Okay, we have this. I can tell you today that
I have exactly this much power coming onto the
system from new hydro, and here's my load

exactly the same. It's virtually impossible.

So a year ago I would

have said Western Copper's coming onto the

system. We better get 40 more gigawatt hours

of hydro on. You know, things change. You

know, it's -- maybe it's a year later now.

Maybe it's a year and a half later.

But trying to balance how

we get, you know, new resources and new

customers at the same time has been a real

challenge over the last couple of year. And

we'll do our best to map all this out for you,

but it's not as easy as all -- it's not as easy

as saying, Okay, we're going to do this and

here's the timeline and here's how much it cost

and here's the customer. This is not Alberta

or BC or Quebec where they -- the years of

planning time ahead of things and the system

can absorb all of those costs to putting a new

project on and the customer is growing into it.

We don't have that luxury.

Q All right. Thank you.

MS. BENTIVEGNA: Thank you, panel. Those

are my questions, Madam Chair.
THE CHAIR: Thank you, Ms. Bentivegna. I will ask at this time if there are any further questions from the Board. There appear to be none. Mr. Landry, any redirect?

MR. LANDRY: I do have a couple of questions in redirect, Madam Chair.

YEC PANEL FURTHER EXAMINED IN CHIEF BY MR. LANDRY:

Q I will go with the most recent one first, and it arises out of a question from Board counsel. And I guess I would put it to you, Mr. Mollard. There was a reference to a certain amount of expense I believe in 2008 relating to the YECL intervention. Do you recall that?

A MR. MOLLARD: Yes, I do.

Q I think it was approximately, if I have the number right, 94,000.

A MR. MOLLARD: That's correct.

Q Now, that 94,000, is that in the 2008 or 2009 forecast revenue requirement?

A MR. MOLLARD: It is not.

MR. LANDRY: The second item, Madam Chair, relates to a question yesterday arising out of Exhibit C1-9 which was the aid
to argument or aid to cross-examination

Mr. Keough introduced and it is in reference
to -- I don't have the specific transcript
reference. I thought I was going to be able to
get to the break and I could get that, but I
think we could centre in on that.

Q  MR. LANDRY: It's to you, Mr. Osler.

There was a discussion with Mr. Keough about
the scenarios relating to Rate Schedule 42, and
you had indicated a reference to an OIC that
dealt with the issue of the requirement that
the rates charged to YECL collect effectively
all of the costs. I wonder if you can just for
the record inform the Board what OIC that is
and what reference you were making in that OIC.

A  MR. OSLER: Madam Chairman, I was
referencing OIC 95-90, but the same thing was
in some earlier OICs, but that's the current
one. I am referencing Section 7 of that OIC
which deals with the setting of wholesale rates
and in effect says those rates must be -- Order
in Council 95-90, Section 7, which is dealing
with the Board fixing rates of Yukon Energy
Corporation for the wholesale power customer in
accordance with the following rate policies,
and it includes those rates must be sufficient
to enable Yukon Energy Corporation to recover
its costs that are not recovered from its other
customers. There's two sections, but they're
both -- that's what I was referring to.

Q  Thank you.

MR. LANDRY: Madam Chair, those are
the only redirect questions that I have.

THE CHAIR: Thank you, Mr. Landry.

We appear to have caught
Mr. Morrison in a particularly generous mood
this afternoon with his undertakings. What
kind of time could we expect those by?

MR. LANDRY: The last one gave me a
little bit of a hiccup. So I'm wondering
whether or not we might say by next Friday.

THE CHAIR: Do we have a date for
that? What would that be?

MR. LANDRY: May 15th, sorry. May
15th.

THE CHAIR: So May 15th, the
undertaking is to be provided.

And I just want to remind
parties that simultaneous argument, written
argument will be due May 22nd and written reply
June the 5th. Are there any other matters any party wishes to bring forward to the hearing? Mr. Maissan?

MR. MAISSAN: I have a question in regards to reply argument. I am going to be travelling around the time when that is due, and I am going to have to prepare any reply very shortly after final argument is due. Should I be doing the same time as I did last time when I had the same problem, forward it to the Board to be circulated on June the 5th?

THE CHAIR: Would the logistics of that work, Ms. Lemke? That would be around June the 5th. It appears to be a workable solution.

MR. MAISSAN: Thank you.

THE CHAIR: I would like to adjourn this hearing, then, and I look forward to receiving everybody's written argument. Thank you for the last two days.

(PROCEEDINGS ADJOURNED AT 6:09 P.M.)

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Exhibit Number B-20: 584

Stage I Carmacks-Stewart/Minto Spur Transmission Projects Initial Cost Estimates, Construction Budgets, and Final Costs ($million).

Exhibit Number C4-5: 421

Paper copy of OIC response.

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<td>C6-1</td>
<td>23 1</td>
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</tbody>
</table>

- **Exhibit Number C3-6**: UCG letter reply re YEC request for extension to file IR Responses, February 23, 2009.
- **Exhibit Number C3-7**: UCG request for further information, March 24, 2009.
- **Exhibit Number C3-8**: UCG request for further information updates, March 24, 2009.
- **Exhibit Number C4-1**: Maissan (Leading Edge) application for Intervenor status, October 18, 2008.
- **Exhibit Number C4-2**: Leading Edge letter re Board Order 2009-1 and Phase II, January 23, 2009.
- **Exhibit Number C4-3**: Leading Edge IRs to YEC, January 27, 2009.
- **Exhibit Number C4-4**: Leading Edge reply re YEC request for extension to file IR Responses, February 23, 2009.
- **Exhibit Number C4-5**: Paper copy of OIC response.
- **Exhibit Number C5-1**: Percival request for Intervenor status, December 1, 2008.
- **Exhibit Number C5-2**: Percival e-mail re representing Hamlet of Mount Lorne, January 8, 2009.
- **Exhibit Number C5-3**: Percival e-mail re YEC correspondence re Board Order 2009-1, Phase II, January 26, 2009.
- **Exhibit Number C5-4**: Percival IRs to YEC, January 31, 2009.
- **Exhibit Number C5-5**: Percival reply re YEC request for extension to file IR Responses, February 23, 2009.
- **Exhibit Number C6-1**: Cathers request for Intervenor status, December 4, 2008.
Exhibit Number C7-1:  
Giesbrecht request for Intervenor status, December 4, 2008.
Exhibit Number C1-9:  
Bundle of aids to cross.
Exhibit Number D1-1:  
Department of EMR request for Observer status, November 28, 2008.
Exhibit Number D2-1:  
Paul Kishchuk (Vector Research) request for Observer status, December 5, 2008.
Exhibit Number D3-1:  
Carcross/Tagish First Nation request for Observer status, December 5, 2008.

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Page 248, Line 10: "attempts" should be "tends"