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October 21, 2008

Yukon Utilities Board
Box 31728
Whitehorse, Yukon
Y1A 6L3

Attn: Mr. Bruce McLennan, Chair

Re: Written Argument YEC/YECL 2009 Phase II Rate Application

Dear Mr. McLennan:

Please find attached Leading Edge's Written Argument.

Thank you for the opportunity to participate in this Phase II Rate Application process.

Yours truly,

John Maissan

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IN THE MATTER OF THE YUKON ENERGY AND THE YUKON ELECTRICAL COMPANY 2009 PHASE II RATE APPLICATION

Heard before the

YUKON UTILITIES BOARD

October 5-7, 2010

WRITTEN ARGUMENT OF JOHN MAISSAN
LEADING EDGE PROJECTS

General Comments

Leading Edge is pleased that Yukon Energy Corporation (Yukon Energy) and The Yukon Electrical Company Limited (YECL) (together the Utilities) were able to work together and develop joint positions to the extent they did to complete this 2009 Phase II Rate Application. While on some issues the agreement did not come until just before the hearing, making it difficult for intervenors to react to, and there were still two issues on which they disagreed (rates and Rider D), overall this was beneficial.

We are also very pleased that Yukon Energy continued to explore the middle ground between the original Options A and B rate designs. Option C rate design is a credible middle ground option.

For ease of reference when the transcript is being referenced the page and line numbers will be used whenever possible and this reference will appear in brackets as Tr for transcript, p for page number, and Lxx-yy for line numbers. For example a reference to the transcript at page 428 lines 17 to 19 would appear as (Tr p428 L17-19). The Yukon Utilities Board is referred to as "the Board".

Specific customer related issue

1. Terms and Conditions of Service – Cost Sharing Period

When Braeburn Lake Christian Camp Association (the Camp) realized a neighbour connected to the end of the distribution line to which they made a very large customer contribution (almost $27,000) 7 years earlier, and did not receive cost sharing from the neighbour, Yukon Energy staff were contacted by telephone. They were told that it was a matter of administration cost that the cost sharing period was limited to 5 years regardless of the level of customer contribution. In a follow-up letter to Yukon Energy (Application Tab 7 Appendix 7.1, pages 7.1D 16 & 17) the Camp recognized that administration cost for small projects could be an issue and suggested the possibility of increasing the cost sharing period for those customers who paid larger amount of customer contributions. When no reply was received from Yukon Energy the decision was made to make representations to the COS and rate design public consultation process to try to effect some change. The Utilities' response through the public process was basically that the existing (5 year) cost sharing policy was a reasonable balance between customer rights and administration costs (Application Tab 7 page 7-4).

Through the Phase II Rate Application interrogatory process Leading Edge tried to explore the balance between consumers and the Utilities' administration costs that was being incurred (LE-YEC/YECL-1-31a) the response was that these costs are not being tracked. So the reality is that no one knows what costs are actually being incurred and it is not unreasonable to assume that if these costs were indeed significant they would be tracked.

Leading Edge also tried to explore how many distribution extension projects involving one or more customers the Utilities would have on an annual basis in which each participating customer paid contributions in excess of certain amounts (LE-YEC/YECL-

1-31 (b) to (g)). The response to the original IR, the request for clarification (Exhibit C1-3), the clarification response dated August 4, 2010 (Exhibit B5), the discussions during Leading Edge's cross examination of the Utilities (Transcript (Tr) pages 149 through 154) on this subject, and the response to Undertaking 4 (dated October 12, 2010) all suggest that the Utilities do not really know how many distribution projects (to which more than one customer connects or can connect in future) are involved (as opposed to individual customer connections not involving distribution lines but that may include primary and secondary lines to which no future customers may be expected to connect) as they only seem to track individual customers.

The data on the individual customers (2007-2009) indicates that between 25% and 30% of non-industrial customers paid individual customer contributions of $10,000 or more (but we do not know how many actual distribution projects to which multiple customers connected as this information is not specifically tracked. Only about 12% of customers paid contributions of $25,000 or more.

Leading Edge also explored how many subsequent customers connected to projects to which the originating customers paid amounts of $5,000 or more (LE-YEC/YECL-1-32). This information was available and provided.

The data from the utilities (2007-2009) indicates that there were no Yukon Energy customers connected to projects in which the originating customers paid $5,000 or more each, and that there were only 9 YECL customers who connected to projects in which the originating customers paid $5,000 or more each. Only 4 customers connected to projects in which the originating customers paid $10,000 or more each, and only 1 customer who connected to a project in which the originating customers paid $25,000 or more each.

It is Leading Edge's view that the data from the Utilities does not support their stance that a reasonable balance between customer rights and administration costs is being achieved. First and foremost the Utilities do not know how much this tracking is costing, so how can they know when a balance is being achieved? Leading Edge accepts that it may not be practical with the systems in place at the Utilities at present to track for 15 years instead of 5 the majority of small projects to which individual customers pay $5,000 or less to connect, however, only a modest percentage of customers pay contributions of $10,000 or more each and only a small percentage pay $25,000 or more each. Furthermore it is clear from the Utilities information that they get very few subsequent customers (4 in the last 3 years) who do connect to the projects for which originating individual customers paid $10,000 or more and only 1 in the last 3 years who connected to a project in which the originating customers paid $25,000 or more each.

The Yukon Government Rural Electrification Program applies a 15 year cost sharing period to <u>all</u> participating clients. Informally the Leading Edge has been told that their administration cost is modest and that this is not an issue of concern to them.

Informal discussions with YECL staff during the breaks at the Phase II Rate Application hearing suggested that if the parameters for longer cost sharing periods could be appropriately set the administrative tracking could be quite modest. There seemed to be an openness to at least discuss and explore the issue further. If the Utilities are willing to

discuss the issue further Leading Edge would be prepared to represent Braeburn Lake Christian Camp Association's interests in these discussions. I know that the Camp will not be unreasonable in their positions.

Request: That the Board order the Utilities to extend the cost sharing period to 10 years for distribution extension projects in which customers pay individual customer contributions of $10,000 or more each, and to 15 years for distribution projects in which individual customers pay $15,000 or more each, and that if the Utilities are concerned that specific parameters are required to ensure reasonable administration costs with these longer periods to discuss and get agreement from interested parties (including the Camp) before implementing more restrictive parameters than currently in place for the 5 year cost sharing period.

Cost of Service (COS) Related issues

2. Allocation and Classification of Hydro Plants and Transmission Lines

If Leading Edge has correctly interpreted the information available to it the classification of the transmission assets in the past have been 100% to demand and the Aishihik and Mayo hydro plants had been classified 60% energy and 40% demand. It is now proposed that these assets all be classified 100% to energy.

In 2006 Yukon Energy had the Board examine its 20-Year Resource Plan. That plan contained proposed new Capacity Planning Criteria which included a Loss of Load Expectation (LOLE) and an "Emergency (or "N-1") WAF and MD system capacity planning criteria" (direct quote from 20-Year Resource Plan page 3-20, underlining added). It also included a WAF or MD "community" criteria. "N" refers to the normal system operating condition and "-1" refers to the loss of the single largest power source (transmission or generation). For the WAF system, and the soon to be consolidated hydro system the largest single power source is the Aishihik power plant connected by the transmission line. The transmission line was considered to be the "weak link".

It is the emergency or N-1 planning criteria that is being cited as the principal reason for this change. Although the Utilities have said that the N-1 is not a COS allocation method (response to CW-YEC/YECL-1-2(a) and (b), and LE-YEC/YECL-1-4(a)), all responses justifying that the Aishihik plant should be classified 100% to energy indicate that the main reason is that is has no capacity credit in the N-1 planning criteria due to the transmission line being the weak link, so to speak (e.g. Application Exhibit B-1 and Tr p109 L6-7). The Utilities also say that you cannot count on the Aishihik transmission line when you need it (Tr p110 L3-4). This supposition is false based on past performance. There have been no instances over the past 10 winters when the line has not been available while there have been several instances where the plant or substation components that connect the plant to the transmission line have caused significant outages (response to LE-YEC/YECL-1-5).

The Aishihik plant has been compared to wind energy (Tr p109 L25 to p110 L1; and p110 L14-21). This is a totally inappropriate comparison wind is not dispatchable as varies from hour to hour, it has to be used when available. Aishihik is completely

dispatchable and furthermore it stores summer energy for dispatch in winter to meet winter peak demands and energy requirements.

We have seen evidence that the Aishihik plant typically contributes near full capacity to the winter peak on the WAF system (CW-YEC/YECL-1-2(e)). Clearly the Aishihik plant is consistently used as one of the main sources to meet winter peak demand. In Leading Edge's view the fact that it is consistently used for the purpose of meeting winter peak demand (in addition to the energy) indicates that a portion of the costs should be allocated to demand. Leading Edge views the past 60% energy and 40% demand as a minimum appropriate demand allocation. We believe that the demand allocation could be higher, particularly when the third turbine is added to plant in about a year's time.

Entirely parallel information and data exists for the Mayo hydro plant and Leading Edge believes that it too should remain classified 60% to energy and 40% to demand.

With respect to the classification of transmission lines Leading Edge can appreciate that the smaller portion of the Mayo – Dawson City line's justification was based on diesel capital savings (overhauls, engine replacements, and plant upgrades) compared to diesel fuel savings the smaller portion should be classified to demand. In respect to the Aishihik transmission line it carries up to 30MW in winter and in a year this may increase to about 37MW, which must be a substantial portion of the line's capacity. It is acknowledged that the average output of the plant is about 12MW, and this is a smaller percentage of the line's carrying capacity.

The Utilities say that the reason for doing a COS is to accurately and fairly represent the system (Tr p167 L4-8). The Utilities have also accepted that a portion of the Mayo – Dawson City line could be classified to demand (Tr p163 L23 to p164 L6), and that a portion of Whitehorse hydro No. 4 could be classified partly to demand (Tr p118 L20 to p119 L4).

The Utilities are not aware of any other Canadian power utilities that have changed their COS classification on the basis of adopting the N-1 capacity planning criteria (response to LE-YEC/YECL-1-4(d)).

Let it be clear that Leading Edge fully supports the N-1 planning criteria and that the "-1" for the WAF or integrated hydro system is represented by the 30MW Aishihik hydro supply, and that the N-1 <u>emergency</u> planning criteria requires diesel or other back-up to be in place for <u>emergencies</u>. Leading Edge does not accept that the N-1 planning criteria should drive the classification of power assets as it has done in this COS. Leading Edge can accept that there is a greater rationale for allocating at least a portion of the transmission assets to energy but considers 100% energy to be an overstatement.

Leading Edge is very concerned that every possible excuse has been used to classify assets to energy and away from demand. This, in our view is driving costs to the industrial class and away from the residential classes in an unfair manner.

Recommendation: That the Board order that the Aishihik and Mayo hydro plants remain classified 60% to energy and 40% to demand.

Recommendation: That the Board order that transmission lines be classified 60% to energy and 40% to demand.

Recommendation: That the Board accept all other classifications as proposed.

3. Contribution of Customer Classes to Coincident Peak Demand

The Utilities have explained a process of assigning or calculating coincident demand contributions by different customer classes to the coincident peak system demand that uses ATCO Electric Alberta data (Tr p243 L10 to p245 L17). While this process, with some cross checks, has been used with apparent success in the past (Tr p158 L22 to p159 L19), there was some concern about how the numbers worked out this time (Tr p247 L4-6). We understand that doing a credible study in Yukon would be very expensive and not cost effective (Tr p247 L7-10). In Leading Edge's opinion a cost of about $2 million (Tr p241 L17-22) is not appropriate for Yukon.

There was some discussion of the practical things that were done for the last study in to cross-check or verify the validity of the adjustment of the data to make the Alberta studies applicable to the Yukon. We understand that there was not the time or opportunity to conduct similar checks as part of this cost of service study. However given the differences between Alberta where gas is available for space heating, water heating, cooking, and various other commercial uses and Yukon which does not have gas but does have a greater reliance on electricity and oil for the same purposes, Leading Edge believes that it is important to do some basic "truthing".

It is our view that there are practical and cost effective checks that can be carried out to check or "truth" the Alberta data so that the adjustments made to the Alberta models will reasonably accurately reflect Yukon realities. The Utilities appear to agree with this (Tr p242 L22 to p243 L1 and p246 L18-21). These may include demand (amperage) readings on portions of various feeders that serve primarily one type of customer, for example residential, downtown small business, large box stores, and large government facilities of various types; spot readings of the loads on various feeders at or near system peak in very cold weather; and specific readings of the loads of the two industrial customers presently on the hydro systems.

Recommendation: That the Board order the Utilities to collaborate to identify and select appropriate cost effective measures to measure adequately actual Yukon specific customer loads so that the ATCO Alberta models can be calibrated or "truthed" to provide more reliable Yukon specific information, and to implement these measures prior to the next Phase II Application.

<u>Rate Design Related Issues</u>

4. Seasonal Rates

Yukon Energy has acknowledged that getting energy (renewable energy implied) in summer is easier in summer that it is in winter and that winter power consumption is higher and that Yukon Energy is focusing projects that provide winter energy (Tr p426

L14-22, and p427 L19-25). It has also acknowledged that water inflows occur primarily in summer (Tr p423 L16-17). Furthermore hydro facilities like the Aishihik plant store the summer water inflows for use primarily in winter (Application Exhibit B-1, Appendix 7.1 p7.1D-29 to p7.1D-32).

In Leading Edge's view there is ample evidence that the hydro availability is primarily in summer and the need is primarily in winter, and furthermore that there capital costs incurred on various assets to make this energy available in winter. When there is inadequate water for energy or hydro capacity to meet peak demands available we use diesel generation to make up the short falls, primarily in winter. In Leading Edge's view that there are thus good reasons for not dismissing seasonal rates out of hand. However given all of the other rate issues the Utilities and the Board has to grapple with and consider I would agree that now is not the appropriate time to pursue seasonal rates.

Recommendation: That the Board orders that seasonal rates not be considered at this time but that they may be reconsidered at some future time when there are fewer pressing rate issues to be dealt with.

5. General Service Sub-Classes

Both Utilities propose to create in future two General Service subclasses, one for large customers and one for small customers (Application, Exhibit B-1, page 4YEC-21 and page 4YECL-12). Leading Edge agrees that this is appropriate and should be done at the next opportunity.

Recommendation: That the Board order the Utilities to institute two General Service subclasses and to design appropriate rates for these two subclasses with the next Phase II Rate Application.

6. Price Elasticity and Demand Side Management

The Utilities have said many times that there is no short term price elasticity (Tr p319 L17-18; L23-25; and numerous other places in the transcripts and in IR responses) and that elasticity studies are not often cost effective to do (Tr p317 L11-16). "Short term" has not been defined for the context in which it was being used. However, under cross examination the Utilities did acknowledge that customers who use electric heating and alternate heating sources (e.g. wood stoves) could respond quickly (Tr p422 L13 to p p423 L7).

The response to YUB-LE-1-3(a) Attachment 3 is a document by the Fraser Institute which clearly indicates in its body and its references credible studies that also shows short term elasticity is real (short term in the references is 1 to 5 years). Furthermore Attachment 1 to this same IR response which is a 15 year comparison between YECL and Northland Utilities (Yellowknife) residential use per customer indicates that over about 3 years the YECL customer usage over Yellowknife increased to about 1,800 kWh per year following about a 10 year period during which YECL customers used about 500 kWh per year more. The 1,800 kWh per year difference has remained steady over the past 4 years. This graph was presented to the public COS and Rate Design workshop

held in December 2009 by the Utilities and can also be found in their Application Tab 7. As pointed out in this response residential electrical rates in Yellowknife are now substantially higher than in Yukon and there is no subsidy program in place.

The increase in relative difference of 1,300 kWh per year per residential customer represents in the order of 18GWh per year over all Yukon residential customers. Leading Edge asserts that this represents a very substantial price elasticity and a very attractive DSM target. However, to realize any significant portion of this potential the appropriate rate signals must be sent.

The Utilities have recognized that the Yukon's Interim Electrical Rebate is counter-productive to consumer conservation action and DSM success (Tr p467 L9 to p469 L5).

Recommendation: That the Board recognizes that there is price elasticity in Yukon over periods of 1 to 3 years even if we do not have specific studies to prove this.

Recommendation: That the Board recognizes that appropriate price signals are an important prerequisite to the success of any DSM / conservation program and takes this into account in their decisions on rate design.

Recommendation: In recognition that DSM / conservation can contribute significantly to reducing the forecasted future diesel requirements that the Board orders the Utilities to come forward at their next GRA with a DSM action program for implementation immediately upon approval (if not already implemented) in addition to their commitment for a DSM Policy Paper.

Recommendation: That the Board informs the Yukon government of its opinion that the IER in its present form is in fact detrimental to the electrical consumers' long term interests and recommends a targeted assistance program to those who can demonstrate a real need.

7. Rate Design

In their Application (Exhibit B-1) the Utilities submitted two different rate design options as they could not agree on a common rate design proposal. Yukon Energy's proposal, Option A, was focused on getting a runoff rate at about 80% of the marginal cost of diesel generation (except for Old Crow) as they considered this to be an appropriate first step to achieving runoff rates that equaled the marginal cost of diesel generation. YECL's rate design proposal, Option B, is very near the status quo (that is present rates with the riders added in) with small upward adjustments in blocks 2 and 3 for residential consumers and General Service consumers.

Both Yukon Energy and YECL proposed three residential rate blocks and four general Service rate blocks. As well both utilities combined the hydro, large diesel, and small diesel zones into a single rate structure and left Old Crow as the only diesel served zone with its own rate structure. The reason for this was that the incremental diesel generation costs in the hydro, large diesel, and small diesel zones were very similar, and Old Crow

was unique with very substantially higher diesel fuel costs (diesel fuel has to be flown in).

In intervenor evidence Leading Edge provided an example for residential non-government class rate design it considered to be superior to both Option A and Option B. Leading Edge's example rate design option was essentially modification of Yukon Energy's Option A (but in the middle ground towards option B) as Leading Edge considered this to be closer to the ideal than Option B. Leading Edge proposal for residential non-government customers limited the block 3 runoff rate to $0.20 per kWh but increased the second block rate to $0.16 per kWh so that more customers in the mid consumption area would experience a bill increase. The purpose for this was to encourage conservation and participation in conservation programs. Leading Edge's proposal made only minor changes to block 1 rates so that the impact on bills in this consumption range would be minimized when the government terminated the Interim Electrical Rebate (IER).

Yukon Energy's Option A was later replaced by Option C (Exhibit B-12) as Yukon Energy's preferred option. Option C reduced the runoff rate to $0.20 per kWh and increased the size of block 2 from 1001-1500 kWh per month to 1001-2500 kWh per month for residential customers. Block 1 rates were increased from Option A and block 2 rates were decreased. YECL's position has not changed they still prefer Option B.

YECL witnesses indicated that they do want to see runoff rates move towards 100% of the incremental cost of diesel generation (Tr p501 L3-18). They also say that if we do not start to reflect the incremental cost of diesel generation in rates now the problem later will be larger (Tr p520 L20-22).

YECL has stated repeatedly that diesel costs are seldom incurred or even forecasted to occur (response to CW-YEC/YECL-1-19(b); YUB-YEC/YECL-1-24(a); Tr p626 L21-25; and others). Under cross examination YECL accepts that about $5.8 million out of a total revenue requirement of $50.833 is for diesel fuel (Tr p555 L3 to p556 L11). Aside from Old Crow where there are higher runoff rates, Option B effectively consolidates the hydro, large diesel, and small diesel zones into one for rate design purposes. And even though $5.8 million (less the Old Crow fuel cost), or about 10% of revenue requirement, is collected annually from the customers in the consolidated rate zone to pay for diesel fuel costs YECL still seems to believe that these costs are seldom incurred or forecasted to be incurred. This is very inconsistent logic. Further more information provided by Yukon Energy at the recent Mayo B hearings indicated that there is now a projected annual diesel energy requirement on the hydro system(s) of 4GWh per year based on long term average water flows (Tr p397 L11-22). This will add materially to the annual average diesel fuel costs.

Leading Edge is of the view that Option C is superior to both Option A and Option B. We are happy with the proposed $0.20 per kWh runoff block but, Leading Edge feels that with respect to the residential non-government class, block 2 rates should be increased somewhat and block 1 rates should be decreased somewhat. Leading Edge believes that block 2 rates should be increased so that more customers in the mid consumption rates would experience a bill increase and that block 1 rates should decrease so as to minimize

the bill impact of IER termination. The block 2 rate concerns are the same as Leading Edge had with Option A – Leading Edge believes that greater conservation efforts would result from DSM programming.

Leading Edge believes that YECL's Option B does not provide the rate signals required in their proposed block 2 and 3 rates to reflect the incremental costs of diesel generation presently being incurred and about to increase in the near future. It appears to us that based on the testimony of YECL witnesses YECL's real overriding concern that drove the design of this option was revenue stability concerns (Tr p314 L13-15; p513 L1-11; p514 L4-10). This means, in our view, that YECL is worried about price elasticity and loss of revenue.

Leading Edge is also of the view that there should be consideration for the fact that the Mayo B hydro project has been approved and that starting about a year from now there will be about 30GWh per year of energy coming onto the system that, absent government capital subsidies costs the same or more than the cost of diesel generation for many years into the future. While Leading Edge is not suggesting that costs not incurred by the rate payers be collected from them, Leading Edge does believe that since there is always an element of subjectivity involved in setting rates the runoff rates could be set somewhat higher than they otherwise may have been to reflect the value of this new energy source. Leading Edge believes that the Board has the discretion to take this into account. This is consistent with the rate making principles as viewed by YECL (YUB-YEC/YECL-1-22(a)) that the production cost of the last unit of energy should equal the value of that unit to the customer.

Recommendation: That the Board adopt a modified Option C specifically with residential non-government block 3 runoff rates at $0.20 per kWh as proposed, with block 1 rates decreased to provide an approximate 10% bill reduction for bills for consumption up to 1,000 kWh per month, and with block 2 rates increased to balance the overall revenue recovered from that class and with rates for all other classes adjusted in an manner consistent with the preceding and other principles and requirements (e.g. OICs) that must be applied.

8. Analyses of Customer Impacts

The Utilities have, as a habit, referred to percentages of bills as percentages of customers. Yet for most customers their bills will vary from lower in summer to higher in winter. This change from summer to winter will be substantially greater from summer to winter for those customers who use electric heating (see information in response to CW-LE-1-1(j)). The Utilities have indicated that looking at actual customer impacts is not practically possible (Tr p377 L15 to p378 L23). However, Yukon Energy was able to provide month by month information on bills in response to an Undertaking at Tr page 246 (Exhibit B-21). Given that this information is available, and that retail customers in Yukon receive each month a bill that includes 13 months of historical consumption (current month plus previous 12, in graphical form), there must be a way to use the information available in the billing system produce a more accurate reflection on typical customer impacts of proposed rate changes.

Recommendation: That the Board order Yukon Energy and YECL to develop a better system of calculating customer impacts for the next Phase II Application.

Terms and Conditions of Service

9. Maximum Investment Levels (MILs)

Leading Edge was not in agreement with YECL's originally proposed residential MILs; however, we do support the revised joint Utilities' position for a two year staged change as put forward on September 30, 2010 (Exhibit B-9).

Leading Edge also supports the other Utilities' jointly agreed to changes put forward in the Application (Exhibit B-1) and the September 30, 2010 filing (Exhibit B-9).

Recommendation: With the exception of the Cost Sharing Period addressed as item 1 in this Argument for which there is a specific recommendation for a change to the Terms and Conditions of Service, that the Board approve the proposals of the Utilities for the Terms and Conditions of service.

Other Matters

10. Rider D

YECL's applied for Rider D to collect or refund balances from a deferral account set up to collect variances in purchase power costs when diesel is on the margin on the hydro system (Exhibit B-2). However YECL acknowledges that diesel is not forecast on the margin in the test year for which the Phase II Application applies but may apply in future when diesel is on the margin (Tr p552 L24 to p553 L14). Under cross examination by Mr. Landry the YECL panel appeared to be unsure of when the deferral account was created but also what parties bore the risk of an error in sales forecasts (Tr p577 L11 to p589 L25). From further cross examination it was clear that YECL had not yet fully worked out the mechanics of exactly how the monies would flow into and out of the account, nor was this process yet before the Board for review (Tr p593 L14 to p603 L8). This information was provided later in response to Undertakings (Volume 3A Undertakings 4, 5, and 6)

Recommendation: Given that the deferral account exists and that YECL will not suffer financial hardship on this particular matter; it is recommended that the Board defer a decision on Rider D until the next YECL GRA when the issues of the deferral account and the mechanics of money flowing into and out of the account can be discussed by all parties in front of the Board.

Recommendation: That the Board order YECL to bring forward in its next GRA the proposed mechanisms and procedures with respect to the proposed Rider D.

Respectfully submitted,

John Maissan
Leading Edge Projects
October 21, 2010