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IN THE MATTER OF THE ATCO ELECTRIC YUKON 2016-2017 GENERAL RATE APPLICATION

Heard before the

YUKON UTILITIES BOARD

November 1 - 3, 2016

FINAL ARGUMENT OF JOHN MAISSAN

Final Argument introductory comments

In the preparation of this written final argument the transcript was referenced by page and line numbers and whenever possible. This reference will appear in brackets as Tr for transcript, p for page number, and Lx-y 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". Interrogatory responses (IR) will be referenced by their identifying numbers.

In this argument I address both issues in which I am in agreement with the applicant, ATCO Electric Yukon (AEY), and issues on which I have a differing view or disagree with the applicant. My silence on issues and requests of AEY in this argument are not to be interpreted as agreement with, or disagreement with, AEY's request or position. I leave these matters to the Board to address based on all the information on the record.

The topics outlined in my final argument below generally follow the order in which they appear in the application.

Section 1 Introduction

1. Deferral account for Board orders or legislative provisions

AEY's request for a deferral account for Board orders and legislative provisions is outlined in the Application on pages 1-4 and 1-5. The need for such an account and the impacts of present and potential future legislative changes and Board orders were explored by the Board in IR YUB-YECL-2. Specific programs that might fall into the legislative changes category were explored in IRs JM-AEY-5, YUB-YECL-6, and YUB-YECL-72.

One of the programs cited under the legislative changes category is the Micro-Generation Program. In response to IR JM-AEY-5 (c, d), AEY provided a table (Attachment 1 to this IR) that provides an analysis of the Micro-Generation Program. Included in that table is a calculation of the net costs and benefits of the program to AEY. In an updated response to this IR, the Attachment 1 table shows that the Micro-Generation Program provided net benefits to AEY of $1,743 in 2014 and $4,268 in 2015. These net benefits will continue to grow each year that the program is in effect and will continue indefinitely into the future.

Contrary to the implications in the Application and IRs referenced in the first paragraph that government programs all pose a negative risk to AEY, the Micro-Generation Program provides a net benefit.

The future IPP program is also cited as a potential risk to which AEY is exposed. However, just as with the Micro-Generation Program, AEY has been at the table with the Yukon government, Yukon Development Corporation, and Yukon Energy developing this program, and continues to be involved with developing the necessary rules, agreements, and interconnection standards for this program (YUB-YECL-2(a)). Given that AEY has been well able to protect its interests in the Micro-Generation Program, there is no reason to believe or suppose that AEY will not be able to protect its interests in the IPP program.

Other programs, such as the commercial energy incentive program, run by the Yukon government, that AEY references, have their effects captured within AEY's load forecasting process. These programs thus provide minimal impact, if any, on AEY's earnings because they are readily apparent, and thus the risk, if any, is minimal.

Recommendation: That the Board does not approve a deferral account for Board orders and legislative provisions.

Recommendation: That the Board, if it does approve a deferral account for Board Orders and legislative provisions, includes all such matters and programs, including those that would benefit AEY financially, for example the Micro-Generation Program.

<u>Section 2 Sales and Revenue</u>

2. Declining sales

In its Application (Exhibit BB-1, AEY details that Primary sales declined about 6 GWh in 2014 relative to 2013 and increased only 2 GWh in 2015 relative to 2014 (Application Table 1, page 2-1, and YUB-YECL-4(a)). The Application (Table 2 page 2-2) shows that these sales figures are below the originally forecast levels in both 2014 and 2015 and substantially below the Board approved sales forecasts for 2014 and 2015. Both the residential and commercial sales are forecast to decrease slightly in 2016 and then increase modestly in 2017 (Application Table 1 page 2-1). This same table outlines an increase in secondary sales of about 2.4 GWh per year in the test years of 2016 and 2017.

Recommendation: That the Board accepts AEY's the sales forecast as presented in its Application, Exhibit BB-1, for the purposes of this GRA.

<u>Section 3 Purchase Power</u>

3. No-cost power

AEY purchases primary and secondary power from Yukon Energy in addition to generating power at the Fish Lake hydro system. With the implementation of the Micro-Generation Program in 2014 ATCO (and also Yukon Energy) started getting power from customers that have installed qualifying energy producing systems, principally solar PV. These systems export power to the distribution system to which they are connected whenever there is a surplus relative to the need of the customer. This export is purchased by the Yukon government from the customers and is available to the utilities at no cost. The total volume of such exports from customers to AEY is still modest (20.043 MWh in 2015) (JM-AEY-5(c-d) Attachment 1 Update Subject to Check) but is growing at a significant rate. AEY should include estimates of this increasing amount of no-cost power for 2016 and 2017 in its table on page 3-1 of its Application and in Schedule 3.1 so that a full picture of energy sources is provided.

Recommendation: That the Board order AEY to provide estimates of no-cost power in its purchase power tables in the application and the relevant schedules.

<u>Section 5 Operations and Maintenance (O&M) Expenses</u>

4. Labour costs

I continue to be concerned that AEY labour costs have been increasing at a rate faster than general inflation. The reasons cited are generally that of existing contracts for the in-scope employees and the need to compete with Alberta for qualified staff (JM-AEY-1, and Tr p244 L15 to p246 L2). Of AEY's approximately 70 employees 34, almost 50%, will be earning over $100,000 per year by 2017 (UCG-AEY-25(a)) and at present 33 already do. It appears to me that AEY does not tightly manage their labour costs.

5. Costs related to name change to ATCO Electric Yukon

In 2014 The Yukon Electrical Company Limited changed its operating name to ATCO Electric Yukon. Costs for this name change are included as part of the $169,000 on "Public Information" costs on Schedule 5.2 page 2 of 3 line 54 as per the description provided. AEY maintains that ratepayers did not pay for this as it was not included in forecast costs (JM-AEY-10, and YUB-YECL-35). This issues was discussed at some length between me and the AEY panel during cross examination (Tr p272 L4 to p275 L24). Effectively what AEY maintains is that because these costs were not part of the forecast costs in setting rates therefore the ratepayers did not pay for it.

What this means in practice is that AEY staff could all have taken holidays in Hawaii and charged it to this account with the only result being that AEY's return on equity (ROE) would have been lower. The ratepayers would not have paid for it. This does not make sense to me. If the name change is not to be paid for by ratepayers it should not be included here and the ROE should be re-stated – it will be higher by these costs. Then the shareholders can pay for it out of their ROE.

In effect the ratepayers have paid for it as part of the $169,000. If it is intended that the shareholder pay for the name change, these costs should be removed from this line and the higher actual ROE should be stated. I believe that the costs associated with the name change should not be paid for by ratepayers.

Recommendation: That the Board orders AEY to remove the name change costs from this account and orders AEY to restate their higher actual ROE in a compliance filing.

6. ATCO control of overall O&M costs

It appears to me that AEY is able to control overall O&M costs according to their actual sales relative to approved forecast sales. In 2013 when sales were above forecast O&M costs were above forecast but in 2014 and 2015 when sales were below approved sales forecast levels O&M costs dropped below forecast levels. This suggests to me that there are AEY controllable elements to O&M costs that are not visible to the Board and/or intervenors in this GRA. This issue is also encompassed in the City of Whitehorse's evidence which raises concerns about systematic over-forecasting of costs. Over the 2013 to 2015 test period O&M costs were under the forecasted level by about 1.1% (Application page 5-2 line 6).

Recommendation: That the Board Orders AEY to reduce forecasted O&M costs for the 2016 and 2017 test years by 1.1%, and to indicate to the Board in a compliance filing in which accounts these cuts will be made.

<u>Section 8 Return on Rate Base</u>

7. Cost of debt

In the eight years 2008 to 2015 inclusive for which data is provided (JM-AEY-14) the applied for and the approved interest rates on debt were never below the actual interest rates incurred. In the 2013 to 2015 test years the incurred interest rates were on a downward trend with time and in both 2014 and 2015 were about 1% below applied for and approved rates. The applied for rates are 4.35% and 4.85% for 2016 and 2017 respectively (Application page 8-5). Given the history of interest rate differences between actual vs. applied for and approved interest rates, the 2016 rate can be assumed to be reasonably close but the applied for 2017 rate is likely higher than will be experienced.

Recommendation: That the Board approve interest rates of 4.35% for both 2016 and 2017.

8. Return on Equity

AEY has requested the Benchmark ROE as determined by the British Columbia Utilities Commission (BCUC) in the Generic Cost of Capital (GCOC) hearing for the years 2016 and 2017, plus a risk premium of 0.6% (Application page 8-4). AEY also proposes to leave their equity thickness of 40% unchanged. In support of their request for the 0.6% risk premium AEY provided a report by Concentric Energy Advisors Inc. (Concentric) who had been retained by AEY to assess AEY's risk and provide appropriate recommendations (Application Attachment 8.1).

YUB-YECL-50(a) Attachment 2 provides the BCUC decision which determined that an appropriate ROE for the Benchmark utility (Fortis BC Energy Inc.) was 8.75% for an equity thickness of 38.5%.

The Alberta Utilities Commission (AUC) has also recently issued a decision which granted ATCO Electric an 8.3% ROE for 2016 and an 8.5% ROE for 2017 with an equity thickness of 37% (Exhibit C-2-7).

These two decisions in particular were discussed in some detail during the cross-examination of the ATCO risk panel by Roger Rondeau (Tr p39 starting at line 14 and continuing to about p53).

In the cross-examination of the risk panel by the parties, the risks to which AEY is subject were discussed. One of the risks discussed was the sales volume risk which is born by AEY. When questioned on this sales volume risk, due to weather and economic factors, by Mr. Marriott, Mr. Coyne of Concentric responds in part as follows:
"… What it does do is it creates more variability in earnings, however, for the utility. … and earnings variability creates incrementally more risk". (Tr p28 L20-25)

Another risk discussed is the risk of AEY customers switching heating fuel sources between electric heat and other heat sources such as oil, propane, or wood. The Concentric report on pages 26 and 27 discusses this matter. Concentric's conclusion is: *"… likely does not have a material effect on the risk profile of AEY."* (Concentric report p27 L2-3).

When I cross examined the panel as to how they came to the conclusion that there was this fuel switching happening in their customer base (Tr p56 L23 to p61 L13) it came to light that there were no studies carried out to support this conclusion. Furthermore it appeared that AEY believed that switching to electric heat from oil or propane involves small plug-in space heaters rather than replacement of heating systems. The discussion cannot but lead anyone to conclude that this fuel switching supposition is very speculative and not based on any hard facts. It appears to be AEY trying to explain a sales variation, and in any case Concentric concludes that it has no material effect on AEY's risk profile.

The responses to IRs and the cross examination of the panel identified the ROE approved by the Board and actually attained by AEY as follows:

Year	2009	2010	2011	2012	2013	2014	2015
Actual	11.35%	10.54%	10.74%	10.18%	10.78%	8.85%	7.40%
Approved	8.93%				8.75%	8.75%	8.75%

(YUB-YECL-63(b), and Tr. P275 L25 to p276 L17)

Despite the significant economic variations and sales variabilities (significantly reduced sales in 2014 and 2015) that have occurred during this period of time, this table suggests that AEY has earned ROEs that, with only one exception (2015), are generally well above approved levels. Contrary to Concentric's conclusion AEY has not had significant variability in their earnings, they have been consistently above approved levels except for one year of the last 7.

It is my conclusion that AEY has flexibility in the way it manages its costs such that it fairly consistently over-earns its approved ROE, and therefor is not subject to nearly as much risk as it tries to make out it is. In my view a fair ROE is the BCUC Benchmark of 8.75% and any risk premium is more than adequately covered by its equity thickness of 40% as compared to BCUC's 38.5%. If AUC standards had applied in Yukon, AEY's ROE might well be set lower.

Recommendation: That the Board approves YECL's requested ROE of 8.75% with an equity thickness of 40% but does not approve an additional risk premium.

9. Smart Grid Study

AEY requests approval of $100,000 for a Smart Grid study to be carried out in 2017 and jointly undertaken with Yukon Energy (Application, page 8-8). In response to YUB-YECL-76, AEY describes the purposes and possible outcomes of such a study. I am familiar with some of the benefits achieved in smart grid approaches in villages in Alaska where very significant amounts of wind energy have displaced diesel generation, and I am convinced that there could be significant benefits to ratepayers in the long term of the utilities embracing a Smart Grid approach in Yukon, both on the hydro grid and in diesel served communities.

Recommendation: That the Board approve the $100,000 budget for the proposed joint (with Yukon Energy) Smart Grid study.

<u>Section 9 Capital Additions</u>

10. Overall capital expenditures 2013-2015

In response to CW-YECL-1 AEY outlines their capital expenditures for the years 2013 to 2015. AEY states that while they have no control over customer driven projects, new extensions in particular, their actual "controllable" capital was within 3.2% of the forecast, $36.748 million vs. a forecast $37.995 million, a difference of $1.247 million.

While on the surface it appears that only $1.247 million of capital projects did not get completed, this bears further analysis. Section 11 of the Application on pages 11-3 and 11-4 is found a summary of 13 projects that went $100,000 or more over budget or actually cost more than $100,000 and for which no business cases had been provided in the 2013-2015 GRA. More details on each of these are provided in Attachments 11-1 to 11-13 to Section 11.

Based on the information provided in the attachments the first 6 of the projects listed exceeded the forecast budgets by a total of $4.7 million. Ignoring the last 7 listed projects for the time being, the 2013 to 2015 forecast "controllable" project expenditure that was actually spent thus represents $36.748 million less $4.7 million or $32.048 million of forecast projects. So the total forecast "controllable" capital was underspent by $5.947 ($37.995 million less $32.048 million) or 15.65% of the original forecast. Contrary to assertions that AEY did a good job managing capital expenditures (Tr p248 L19-22) it appears that AEY actually did a poor job managing their capital program.

Clearly a significant number of forecasted capital projects did not get done, had they been done the "controllable" capital budget would have been exceeded by $4.7 million or more. Many projects must have been dropped or deferred, but AEY provided no information on them. This raises questions about over forecasting of capital requirements, or at least including in capital forecasts "nice to have projects" that are not really necessary and that can be deferred when other projects come in over budget.

Recommendation: That the Board order AEY to provide detailed information on capital projects that have been deferred or dropped; the level of detail is to be commensurate with the detail required in capital forecasts.

Recommendation: That the Board reduce the "controllable" capital budget, after any and all other adjustments, by 3% and order AEY to indicate in a compliance filing where these cuts were made.

Comments and recommendations on some specific capital projects listed in the Application on pages 11-3 and 11-4 that have gone over budget, will be provided under Section 13, Prior Board Directives Summary.

11. Conversion of street lights from HPS to LED

AEY is seeking direction from the Board with respect to the handling of costs for the conversion of street lights from high pressure sodium (HPS) to light emitting diode (LED). The issue was discussed at some length in various IRs (YUB_YECL-10, CW-YECL-27, and YEC-AEY-5). AEY estimates that the costs involved would be $270,000 in diesel served communities and that the total cost for all of AEY's service area would be about $2 million (spread over several years((YUB-YECL-10(b)). The options for the treatment of costs are (1) to require contributions from the customer for the cost or (2) to make the cost a system cost.

The attachments to YUB-YECL-10(b) outline that there is a net cost saving from year 1 in AEY's diesel served communities. This cost saving is realized in reduced fuel purchases and will benefit all ratepayers. Also a benefit, but not calculated and accounted for, are reduced costs from lowering winter peak capacity requirements in diesel served communities.

For the hydro grid the power purchase savings for AEY are modest and do not fully cover the capital cost. However, in addition to power purchase savings there are savings that accrue to Yukon Energy, and ultimately all ratepayers, in reductions to winter energy generation requirements and reduced capacity requirements due to reduced system peak loads. As we hear repeatedly, conservation and efficiency is the lowest cost source of capacity and energy.

Recommendation: That the Board instruct AEY to proceed with conversion of street lights from HPS to LED as a system cost and that priority be given to diesel served communities.

<u>Section 11 Prior Board Directives</u>

12. Old Crow Plant Expansion

This project was Business Case #8 in the YECL (now AEY) 2013-2014 GRA. It was budgeted at $1.95 million spread out over 2013 and 2014. I recommended approval and urged AEY to make use of the winter road to be put into Old Crow in early 2014. The description in the Business Case #8 project cost was comprehensive and implied that everything necessary was included. Freight to the site was also included. At the time of the hearing AEY was aware of the planned ice road and the other community projects for which the ice road was desired (store and fuel storage depot).

AEY has been operating in Old Crow for many years and is, or should be, well aware of all of the challenges. For a project estimated to cost $1.95 million to go over budget by $1.3 million in design costs (building and electrical) (Application Section 11 Attachment 11.2 page 1) and over budget by a total of $2.616 million is well beyond any reason. There must have been either incompetence, or negligence, or poor management, or some of all of them involved. Prudent management of the project was clearly not exercised. When AEY ran into design cost overruns and/or local logistical difficulties because of the other projects underway in Old Crow, the project should have been suspended and re-assessed. And probably brought back to the Board when costs could not be brought under control.

Recommendation: That the Board retain experts to review and audit the entire project execution process and cost, <u>OR</u> the Board disallow $1 million of the $2.616 million cost overrun and remove it from rate base.

13. Old Crow Unit 4 addition

In its 2013-2015 GRA AEY provided Business Case #10 for the addition of unit #4 (400 kW) to the Old Crow diesel plant at a forecast cost of $500,000. The Application at Schedule 9.2 page 1 of 6 at line 30 suggests that this was accomplished at a cost of $504,000 in 2014 and $108,000 in 2015 for a total of $612,000 or $112,000 over budget. However, no business case type description was provided as required (Application page 11-3).

Recommendation: that the Board order AEY to provide the required business case type description, as required by previous Board order, in its compliance filing.

14. Old Crow Unit #3 Replacement

In its 2013-2015 GRA AEY provided Business Case #15 to replace its 170 kW diesel generator unit #3 with a new 250 kW diesel generator in 2015 at a forecast cost of $500,000. AEY is now putting forward in this 2016-2017 GRA a Business Case (Appendices Section, Appendix #5) to replace this 170 kW generator with a 600 kW unit.

The present business case lays our AEY's reasoning as being the growth in peak load, and AEY states in part "… *it is expected that the operational hours on a 250 kW unit if installed would continuously decrease with load increase. …*" (Appendix #5, page 2). The load duration curves provided indicates that plant loads as low as 130 kW occur for more than 100 hours per year, and the total number of hours with loads of 190 kW or less is about 1,720 hours (estimated from the graph). This is less than 80% of the capacity of a 250 kW generator and within the ideal range for a 250 kW generator (JM-AEY-27(b)).

In addition to the planning requirement of having redundant diesel capacity to meet a community peak load, AEY further states that it is also desirable to have redundant power plants ((Appendix 5 page 2; and Tr p484 L16-18). The desire to have two independent and completely redundant power plants in a community is well beyond any planning criteria approved by the Board. The need to have a second building is not in question, what is in question is the prudency of the decisions about what size generators to put into this plant which operates as an extension of the existing plant.

Even the next larger size generator of 400 kW (already installed in the new plant) would be running below AEY target of 50% loading for these 1,720 hours per year (JM-AEY-27(b)). Furthermore AEY has known that significantly more solar PV capacity was planned for Old Crow, even if a firm in-service date was not yet known, before the decision to upgrade to a 600 kW generator from 250 kW. This 330 kW solar PV capacity will reduce the number of plant operating hours at higher loads on the diesel plant with the result that significantly more hours will be run with low loads on the diesel plant. For all of these hours a smaller rather than a larger diesel generator would be most appropriate. Plant efficiency will suffer as the larger generators will be very lightly loaded.

At the time consideration was being given to increasing the diesel generator size from 250 kW to 400 kW or 600 kW, AEY would have known from the 2014-2015 experience of what would have been involved in installing a 400 kW generator. And AEY could or should have known or investigated the weight limitations of various practical transportation options. After all AEY already has a 600 kW generator in Old Crow and should know.

I can, to some extent, appreciate that a generator larger than 250 kW might be desired, but anything beyond 400 kW simply was and is not necessary. A 400 kW could be transported into the community easier than a 600 kW unit, and as experienced in 2014-2015 with a cost of $612,000, could be done at about half the projected cost of installing a 600 kW unit.

With respect to the solar PV project, AEY is a key player in this matter as AEY will need to hold the power purchase agreement (PPA). The larger the diesel generators in the plant the higher the minimum diesel plant loading that AEY would be willing to consider in negotiations with planned and potential local power producers such as the Old Crow solar PV project.

I am very concerned that AEY opted for a larger than necessary diesel generator for reasons other than efficient plant performance. These reasons may include providing themselves with a stronger negotiating position with respect to a PPA with the proponents of the Old Crow solar project. The choice seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this remote diesel served community. The choice of a 600 kW generator will reduce opportunity for, and add costs to, renewable energy projects in Old Crow.

Recommendation: That the Board reject the plan to install a 600 kW generator in Old Crow and instead authorize the installation of a 400 kW unit at a cost of $612,000 plus $100,000 for cost increases since 2014-2015.

Recommendation: That the Board order AEY in negotiations with proponents of the Old Crow solar project to allow diesel displacement down to a diesel plant load of 130 kW (which is the low level load that the plant now experiences) without penalty or cost to the proponent.

<u>Section 12 Diesel displacement</u>

15. Renewable energy study

In its Application starting on page 12-2 AEY outlines a $500,000 Renewable and Alternative Energy Study that it wishes to do. A Request for Proposals (RFP) for study work appeared in the newspapers after the conclusion of the GRA hearing.

During the hearing AEY indicated that they were behind where they hoped to be at this time (Tr p330 L9-19). It is not realistic to think that AEY could prudently spend the entire proposed study budget subsequent to a Board decision.

In the description of the study AEY makes it clear that they wish to develop company owned renewable and alternative energy sources (Application p12-2 L18-21). Such projects could and would be in direct competition with IPP proponents presently planning projects. In my view it is totally inappropriate for ratepayers to be funding AEY to compete with the private sector who put their own monies at risk and remove operational risks from AEY (or Yukon Energy) customers who ultimately benefit from these projects.

I have a very significant concern that while AEY says that they are keen to incorporate renewable energy generation into their diesel grids, in the two places where there are planned projects (Destruction Bay – Burwash Landing and Old Crow), there are decisions and actions carried out by AEY that suggest the complete opposite. See the preceding No. 14 and the following No. 17 for more detail.

There exists a large body of public knowledge on renewable- diesel hybrid community power systems in Alaska already. Transferring this body of knowledge to AEY should not take a very expensive study. ATCO Electric (and through them AEY) is participating in work being done by the 4 Canadian power utilities operating across northern Canada through the Industrial Research Chair in Northern Energy located in Yukon College's Cold Climate Research Centre, and funded to a large degree by NSERC. Again there is no need to re-invent the wheel or to duplicate work that is or will be funded through this arrangement.

AEY mentions work being jointly done or about to be done with the Yukon Government, the Kluane First nation, and the federal government at destruction Bay. The understanding is that CANMET will fund the Destruction Bay – Burwash Landing gird impact study for the proposed Kluane wind project. Again no need to duplicate studies or costs.

There are portions of the proposed study work that are appropriate and necessary for AEY to do. These include: (1) any work to patriate the existing body of knowledge that has accumulated in other jurisdictions, such as Alaska and Northwest Territories, with respect to wind-diesel and solar-diesel and storage experience; (2) any studies not already being undertaken by other bodies with respect to the integration of renewable energies into diesel grids; and (3) the improvement in efficiencies of existing diesel plants using modern technology such as variable speed diesels, a wider range of generator sizes, and the utilization of residual heat from diesel plants. The initial focus should be entirely on Destruction Bay – Burwash Landing, Old Crow, and Watson Lake.

Work that should not be included in this program are things that would put AEY in competition with the private sector. Included would be work such as: the collection of wind or solar resource data, and any pre-feasibility studies or feasibility studies of projects without first soliciting and encouraging IPP opportunities for that purpose.

Recommendation: That the Board not approve the proposed study as presented.

Recommendation: That the Board approve study costs of up to $150,000 for studies required to prepare for the significant displacement of diesel generation in Destruction Bay – Burwash Landing, Old Crow, and Watson Lake using renewable energy sources, including wind and solar PV.

Recommendation: That the Board approve $50,000 for a study on how to improve the fuel efficiency of AEY's diesel plants, including the utilization of residual heat, that applies to all of AEY's diesel plants.

Recommendation: That the Board orders AEY to submit the detailed Terms of Reference for each proposed study to the Board and registered intervenors in this proceeding at the time the RFPs are issued, and that comments are solicited before awarding and contracts for these studies.

Recommendation: That the Board instruct AEY to file the completed study reports with the Board and registered intervenors in this proceeding as soon as they are completed.

Recommendation: That the Board order AEY to come back before the Board before implementing any action arising out of the study findings.

<u>Section Appendices – Business Cases</u>

16. Appendix 3 Watson Lake Bi-Fuel Project

The Watson Lake bi-fuel project was first brought forth by AEY in the 2013-2015 GRA and while the project was not approved to go into rate base, the costs that were incurred were collected in work in progress (WIP). AEY has again brought forth this project as a business case, Appendix 3, to their 2016-2017 GRA. This potential project was the subject of numerous IRs from all intervenors and the Board, and the subject of discussion during cross-examination of AEY at the oral hearing.

In the business case the economics of the project is examined including scenarios with various oil (diesel source) and gas (LNG source) prices (Appendix 3 pages 8-9). Of the 12 scenarios provided in tables 2 and 3, 2 have a negative 20 year NPVs and 3 are below $2 million in NPV. Four scenarios are at $5 million NPV or higher. The positive financial margins for LNG over diesel are thus small. During cross examination by Ms Middler, AEY's Mr. Tenney acknowledges that the "…*financial model hasn't assumed that we have renewables coming in and at what penetration level. So it's looking at status quo*." (Tr p328 L8-11). In other words the economic comparison between diesel and LNG assumes that all electrical loads will be served by diesel or LNG for the next 20 years.

Ms. Middler also posed the following question: "*And how will the ratepayer investment in this fossil fuel substitution allow for future renewable power generation and not be a barrier to it?*" (Tr p323 L5-8). To this Mr. Tenney responds in part "*In the near to medium term, we still think we're not going to be able to get away from having thermal generation for base load requirements.*" (Tr p323 L22-25). Note that the focus in the response has now shifted to "base load requirements" rather than serving the entire Watson Lake load with diesel or LNG. When asked whether "base load" means capacity Mr. Tenney responded as follows: "*yes, I think that's mostly what I mean, that when you flip the light switch, that there's power there to back that up. And so with intermittent sources like wind or solar, you can't guarantee that when you flip the switch it's there, but when you have something like a thermal facility like diesel or LNG, you probably have a capacity factor closer to the 92 percent level, whereas you're probably … solar in the Yukon, you're probably closer to the 10 or 12 percent. So that's what I mean when I talk "base load."* " (Tr. P327 L3-13). This suggests to me that there can be renewables on the system and that diesel or LNG generation is operating as well. However, no amounts or possible percentages were provided, and no economic analyses of this possibility were provided.

The Yukon's IPP policy (provided in YUB-YECL-72(a) Attachment 1) provides for 2,100 MWh of generation to be available to Watson Lake under the Standing Offer Program portion of the IPP Policy. This is about 14.2% of the expected generation requirement of 14,795 MWh for Watson Lake in 2017 (Application Schedule 4.2 Line 10). The economic comparison referenced earlier did not examine the economics of serving only 86% of the load, i.e. not any lesser amounts (than the entire load) as could be interpreted use "base load". Any reduction in the Watson Lake load by the addition of renewables will reduce the already weak calculated economic benefits of a bi-fuel project, and we know that the IPP Policy allows 2,100 MWH to be added no matter what. Any further generation added under the Micro-Generation Program will displace more diesel generation and further erode the economics of the bi-fuel conversion project.

The ratio of the price of energy in natural gas to the price of energy in oil prior to 2006 has typically ranged from 70% to 100% (JM-AEY-24(a)). Thus the cost of energy in natural gas has historically been slightly cheaper than the cost of energy in oil. In 2006 this dropped to about 50% and presently it is at about 36.2% based on one set of references (JM-AEY-24(c)).

The economic comparison between diesel and LNG in Watson Lake must also take into account the refining and transportation of diesel fuel and the liquefaction and transport of LNG. The liquefaction and transportation of LNG is a higher percentage of the delivered cost than refining and transportation of diesel, so the economic evaluations must look at the delivered costs of these fuels. AEY indicates that the project breaks even over 20 years with a price for LNG, on a per litre of diesel equivalent basis, is 75.6% of the cost of delivered diesel (JM-AEY-24(d)).

In response to IR JM-AEY-2-1 Attachment 1 pursuant to a response to an undertaking in Transcript volume 2 at page 301, lines 2-7, AEY provides (for January 2011 to present) the ratio of costs of delivered LNG on a per litre of diesel equivalent sourced from (1) Altagas in Alberta and (2) Fortis BC, and compares these costs to the actual costs of delivered diesel in Watson lake. Over the past 12 months the ratio averages 69.5% from the closer more cost effective source of Altagas. From Fortis in BC the ratio over the past 12 months is 82.9%. In other words the project would presently be uneconomic using LNG sourced from Fortis in BC and only just economic using LNG sourced from Altagas in Alberta.

This analysis shows how marginally economic the project is with the energy in gas presently at about 36% of the cost of energy in oil. Given that the pre-2006 range going back indefinitely has been 70% to 100%, it would only take a relatively small increase in this ratio towards the historic norm to make the LNG option uneconomic. To assume that this ratio will not move towards the historic norm from the present over the next 20 years is to assume a very high risk indeed . In my opinion not one that should be passed on to ratepayers.

To summarize there are high risk aspects to this project. There is a very high likelihood that renewable energy generation will be added to the Watson Lake grid due to the IPP and Micro-Generation Programs, and this will decrease the volume of diesel that can be displaced by LNG. This in turn will erode the economics of the bi-fuel conversion project. There is also, in my view, a very high risk that the price of energy in gas will increase relative to the price of energy in oil from its present 36% to something closer to the historic 70% to 100% ratio over the 20 year project life. It would not take much of a shift in this ratio to make the bi-fuel project uneconomic, even from the closer source of LNG. It is already uneconomic with BC sourced LNG.

Recommendation: That the Board not approve the Watson lake bi-fuel project and that the costs expended to date by AEY, about $549,000 ($494,000 + $55,000), be amortized over a 5 year period.

Recommendation: That the Board urge AEY to channel its off-diesel efforts into the acquisition of local renewable energy sources, including the issuance of an RFP for renewable energy.

17. Appendix #6 and Appendix #11 Destruction Bay units 2 and 3 replacement

AEY proposes to replace the two smaller units in the Destruction Bay diesel plant, units #2 (300 kW) and #3 (230 kW) with larger units of 400 kW and 315 kW respectively. It appears that unit #3 may already have been replaced as of the date of the hearing (JM-AEY-27(e)). If this is the case then having this unit replacement in the application makes a mockery of the GRA process.

A fair bit of solar capacity has been added in Destruction Bay in recent years and significant efforts are underway to establish a wind project of 300 kW there too. AEY seems to be ignoring these contributions to generation which will increase the dispatch hours on their smaller generators. However, a 400kW generator may be justifiable in addition to the existing 600 kW generator, and if installed it would be increasing significantly the dispatch time on the 220 kW generator, thus nullifying the argument provided by AEY on page 1 of Appendix 11.

As is the case for the up-sizing of generators in Old Crow, I am very concerned that AEY is opting for larger than necessary diesel generators for reasons other than efficient plant performance. These reasons, here too, may include providing themselves with a stronger negotiating position with respect to a PPA with the Kluane wind project – which AEY has been aware of for many years. The choices seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this diesel served community. The choice of 400 kW and 312 kW generators to replace generators of 300 kW and 220 kW will reduce opportunity for, and add costs to, renewable energy projects in Destruction Bay – Burwash Landing, a smaller generator should have been retained.

Recommendation: That the Board approve the installation of one 400 kW generator in the Destruction Bay plant by replacing one of the existing smaller units.

Recommendation: That the Board not approve the replacement of unit #3 CUL 230 kW with a generator of 312 kW in capacity, but instead replace it with a generator no larger than 250 kW.

Recommendation: That the Board order AEY to provide the 2015 load duration curves for the Destruction Bay plant in its compliance filing.

Recommendation: That the Board order AEY in negotiations for an IPP with the proponents of the Kluane wind project to allow diesel displacement down to a load level equal to the lowest normal 2015 dispatch level without penalty or cost to the proponent.

Respectfully submitted,

John Maissan
November 24, 2016