



YUKON ENERGY CORPORATION

2017/2018 GENERAL RATE APPLICATION
ROUND 2 INTERROGATORY RESPONSES FILED

April 6, 2018

**ATCO Electric Yukon
(AEY)**

1 **TOPIC: Risk Profile**

2
3 **REFERENCE:**

4
5 “YECL’s proposal would fundamentally change how all diesel-related forecast risk is
6 managed in Yukon (please refer to Table 1-1 for review of these traditional risk sharing
7 relationships), and in effect seeks to replace the DCF with a diesel deferral account that:

- 8
9 • At a basic level the proposal submitted by YECL would provide the basis for each
10 utility to have a diesel deferral account that would fully protect and insulate each
11 utility from any diesel related forecast risk, regardless of the cause; and
12
13 • In contrast, as reviewed above, the proposal submitted by YECL would do
14 nothing to manage on behalf of ratepayers the fundamental concerns regarding
15 rate instability due to water variability on a predominantly hydro-based system.

16
17 Historically, each utility has carried the risk for increased or decreased costs due to
18 changes in the load compared to GRA forecasts and specifically with regard to load
19 changes, equipment availability (i.e., unexpected maintenance or outages, except where
20 such charges are appropriately part of insurance claims or uninsured losses) and
21 generator efficiency.

22
23 ...

- 1 Table 1-1: traditional Diesel-related regulatory risk sharing relationships in Yukon, YEC
2 Supplemental Filing
3

Factors that affect diesel generation requirements	Ability to forecast	Who carries risk for forecast inaccuracy	How is risk addressed
1. Fluctuation in diesel price from GRA forecast	Each utility provides a diesel price forecast for the test years; actual fuel prices may vary considerably from forecast due to volatile market conditions that are outside the utility's ability to forecast	Ratepayers	Rider F and Diesel fuel price variance account (DFPVA)
2. Availability of water and / or wind	Each utility provides a forecast of expected LTA hydro generation; actual hydro generation may vary considerably from forecast depend on water availability in a given year.	Ratepayers	Diesel contingency fund
3. Volume of interconnected grid sales	Each utility forecasts the volume of sales in GRA test years.	Utilities	Utility forecast risk
4. Location of load (line losses)	Each utility provides forecast of line losses in test years.	Utilities	Utility forecast risk
5. Operation of system	Each utility provides sales and generation forecasts based on its knowledge regarding how the system is expected to operate	Utilities	Utility forecast risk
6. Unexpected event / loss	Not forecastable	Ratepayers	Reserve for injuries and damages (RFID) and insurance.

4

1 *YEC supplemental filing, June 30, 2014, pp 1-7 to 1-8*

2
3 “Specifically, items, such as efficiencies or inefficiencies related to actual YEC operation
4 of its hydro or thermal generation facilities in any specific year are not addressed in LTA
5 estimates such as those provided by YECSIM. If operational decisions result in the
6 system being run more efficiently than assumed in the LTA estimates, then there will be
7 more hydro generation [and less thermal] and a larger payment by YEC into the DCF (or
8 a reduced rebate to YEC from the DCF); if operational decisions result in less efficient
9 operation and higher diesel generation than assumed in the LTA estimates, then the
10 YEC payment into the DCF will be smaller (or the rebate to YEC from the DCF will be
11 larger).
12

13 Overall, YEC seeks to operate its facilities as efficiently as possible. The goal is to use
14 as much water as allowed in order to reduce thermal generation requirements. To this
15 end, YEC’s staff continuously monitor the elevations in YEC’s reservoirs, based on
16 actual levels and the trajectory of the water usage to low supply levels. Based on this
17 monitoring, operators are advised what flow of water they can access. Updates are done
18 several times a week, but can be daily, especially when approaching low supply levels in
19 spring.”
20

21 *YEC response to YUB-YEC-1-6(b), ERA Part 1 Application*

22
23 “Yukon Energy’s actual thermal generation cost and net income are determined each
24 year solely based on the DCF Term Sheet Table [Table 3.4-1] as approved by the Board
25 for determining expected diesel generation for the actual grid load.”
26

27 *YEC response to YUB-YEC-1-6(a), ERA Part 1 Application*

28
29 “...the purpose of the DCF mechanism (and the earlier LWRF) as originally established,
30 and as proposed to be updated and re-activated in the Application, is to provide a
31 ratepayer trust fund (i.e., a fund that is funded by, and maintained for, the benefit of
32 ratepayers) to smooth customer rate changes driven by changes in actual thermal
33 generation costs caused by variances from LTA levels of hydro and wind generation **due**
34 **solely to water and wind availability.**” [emphasis]
35

36 *YEC Argument, October 29, 2014, page 5*

1 **PREAMBLE:**

2
3 AEY is interested in the regulated risk profile of the DCF and the purpose of the DCF.
4

5 **QUESTION:**

6
7 a) Please confirm that, under YEC's DCF proposal, YEC does not carry the
8 "4. Location of load" diesel-related risk described in the referenced table above. If
9 not confirmed, please explain. If confirmed, please explain who carries the
10 "4. Location of load" diesel-related risk.
11

12 b) Please confirm that, under the DCF proposal, YEC does not carry the "5.
13 Operation of system" diesel-related risk described in the referenced table above.
14 If not confirmed, please explain. If confirmed, please explain who carries the "5.
15 Operation of system" diesel-related risk.
16

17 c) Please confirm that the proposed DCF mechanism does not isolate cost
18 variances due "solely to water and wind availability". If not confirmed, please
19 explain. If confirmed, please discuss whether YEC believes the proposed DCF
20 fulfills its purpose.
21

21 **ANSWER:**

22
23 **(a), (b) and (c)**
24

25 As explained in detail below, YEC cannot confirm the statements made in **(a), (b) and**
26 **(c).**
27

28 Subject to the limitations discussed below, 1) YEC does carry the risk between GRAs for
29 forecast inaccuracies in items 4 and 5 in Table 1-1, and 2) the proposed DCF
30 mechanism does isolate cost variances due "solely to water and wind availability".

31 In summary, YEC believes that the proposed DCF fulfills its purpose, subject to the
32 limitations related to the DCF cap as discussed in Section 1.4 of Appendix 3.4 of the
33 GRA Application.

34 YEC believes that the proposed DCF provides a consistent and reasonable basis to
35 separate thermal cost variance due to water and wind availability (to be borne by

1 ratepayers) from thermal cost variance due to changes in total grid generation load (to
2 be borne by the utilities).

3 Table 1-1 referenced in the above question from YEC's Supplemental Filing of June 30,
4 2014¹ described how diesel-related forecast risk has traditionally been managed in
5 Yukon.

- 6 • It highlights key separations between ratepayer risks for forecast inaccuracy (for
7 fuel price, water and/or wind availability, and unexpected events/losses) and
8 utilities risks for forecast inaccuracy (for volume of interconnected sales, line
9 losses and operation of the system).
- 10 • Other mechanisms than the DCF exist to isolate fuel price variance (Rider F and
11 Diesel Fuel Price Variance Account [DFPVA]) and unexpected event or loss
12 (Reserve for Injuries and Damages [RFID]).
- 13 • The prime purpose of the DCF, and the LWRF that was implemented prior to the
14 DCF, is therefore to separate thermal cost variance due to water and wind
15 availability from thermal cost variance due to changes in total grid generation
16 load.
- 17 • The DCF and the LWRF have each, to the extent feasible, accomplished this
18 purpose.

19 The following are noted with regard to specific items raised in the question:

- 20 • Item 4 in the referenced table addresses line losses arising from load location. As
21 such, line losses get added to sales and become part of overall generation.
22 Under the DCF as approved by the Board, YEC bears the risk for changes in
23 diesel generation due to changes in overall generation load requirements.
- 24 • Item 5 in the referenced table addresses all potential operation risks that could
25 affect diesel generation risks. The LWRF and the DCF as proposed in the
26 Application have removed specific material non-water-related thermal generation
27 operation risks, e.g., risks related to RFID events, capital projects, thermal unit
28 fuel efficiencies, and (as proposed for the first time in the current Application)
29 thermal generation maintenance and run-up requirements.

¹ The same table is provided as Table A2.1-1 in YEC's December 6, 2017 ERA Application filing.

1 YEC is not aware of any consistent and reasonable way to isolate operation risks
2 related to use of water for hydro generation to the extent that these may impact
3 thermal generation costs. Such isolation has not been attempted in either the
4 LWRF or the DCF. Further, as noted in the response to YUB-YEC-1-6(b) (ERA
5 Part 1 Application), YEC has well established systems to monitor its use of
6 available water, and is not aware of any material impacts on the effectiveness of
7 LWRF or DCF determinations related to the water management element of its
8 systems' operation.

9 Overall, water-related variances on the Yukon Integrated System (YIS) can and will
10 create very material changes in annual thermal generation costs over the life of existing
11 hydro generation assets. The DCF fulfills its purpose to isolate thermal cost variance due
12 to water and wind availability from thermal cost variance due to changes in total grid
13 generation load.

1 **TOPIC: Price Signals**

2
3 **REFERENCE:**

4
5 “the DCF has been established to provide stability for rates, and to
6 reflect the underlying long-term valuation of renewable hydro and
7 wind generation (where economic feasibility typically is assessed
8 based on long-term average energy supply). In this context,
9 intergenerational equity is enhanced to the extent that the DCF is able
10 to provide rate stability – and price signals (i.e., higher rates) during a
11 drought to promote conservation are not seen as fair or reasonable.”

12
13 *YEC response to AEY-YEC-1-3(e), YEC 2017/18 General Rate*
14 *Application*

15
16 “YEC has a \$10 million line of credit that would be used to finance a
17 DCF shortfall up to the current cap of \$8 million. If the Board directed
18 that this cap would be increased to \$16 million, YEC would propose to
19 accrue cash sufficient to cover the increase in a trust bank account
20 over a reasonable period of time. This approach would avoid finance
21 charges on this excess balance.”

22
23 *YEC response to AEY-YEC-1-3(b), YEC 2017/18 General Rate*
24 *Application*

25
26 **PREAMBLE:**

27
28 AEY is clarifying YEC’s discussion of price signals.

29
30 **QUESTION:**

- 31
32 a) Please confirm that YEC is of the view that the DCF provides a long-term price
33 signal based on long term average hydro availability that helps promote
34 intergenerational equity.

1 b) Please confirm that YEC is of the view that the DCF does not provide a short-
2 term price signal – i.e. that consumers are not encouraged to conserve energy
3 when hydro energy is unavailable through their electricity rate.

4
5 c) Please consider the following hypothetical scenario. “A large, new customer is
6 connected for a term of 10 years. The customer uses approximately 25% of the
7 grid energy each year. At the beginning of the term, the DCF is at its cap. Water
8 is low throughout the term of the customer’s connection. At the end of term, the
9 customer is disconnected and has benefited approximately \$4 millions from the
10 DCF, the DCF is depleted, and YEC has borrowed against its line of credit to the
11 lower DCF cap.” For this scenario, please discuss:

12 i. Has the DCF operated as intended?

13 ii. If the answer to (i) is affirmative, please explain why this customer should
14 not be provided a short-term price signal to encourage conservation if
15 hydro is low or unavailable.

16
17 **ANSWER:**

18
19 **(a) and (b)**

20
21 The statements in these questions reflect overall rate setting objectives for YEC GRA
22 rates. However, the DCF mechanism as such only provides price signals when these
23 objectives are not met, i.e., when the DCF cap results in Rider E rebates or charges.

24 GRA rates for YEC are currently approved based on long-term average (LTA) hydro
25 generation. As such, current GRA rates for YEC are not intended to reflect variances in
26 costs related to forecast short-term (ST) water availability. Accordingly, price signals
27 based on current GRA approved rates provide long-term price signals as regards water
28 availability, and do not provide a short-term price signal in this regard. Please see
29 response to YUB-YEC-2-13 for discussion of LTA versus ST alternative price signal
30 issues.

31 The current DCF reflects the LTA approach adopted for current GRA rate approvals.
32 Excluding DCF cap impacts, the current DCF does not provide “price signals” - it only
33 addresses year-end outcomes, ensuring that YEC’s final thermal generation costs equal
34 LTA hydro availability for the actual total firm grid generation in each year and that the
35 balance in the DCF fund is adjusted accordingly at each year end.

1 However, DCF cap impacts can modify the GRA approved rates through Rider E rebates
2 or charges, i.e., rebates occur when the \$8 million DCF cap maximum is exceeded (as
3 has been the case since 2013), and charges occur if the -\$8 million DCF cap minimum is
4 exceeded (as would occur in a drought [see Appendix 3.4 of GRA Application,
5 Attachment 3.4.4]). The net result of Rider E rebates or charges can be as follows:

- 6 • Rider E rebates result in rates that end up reflecting a form of short-term price
7 signal (related to water availability) when abundant water availability and a full
8 DCF enable net rate reductions below rates required at LTA hydro availability
9 levels. [See ERA Application, pages 2-11 and 2-12.]
- 10 • Rider E charges result in rates that end up reflecting a form of short-term price
11 signal (related to water availability) when drought and a depleted DCF require
12 rate increases above rates required at LTA hydro availability levels. Appendix 3.4
13 of the GRA Application, Attachment 3.4.4 shows that at the GRA forecast load of
14 about 420 GW.h/yr. and the current +/- \$8 million DCF caps:
 - 15 o The average annual Rider E charge needed to recover -\$8 million as a
16 minimum cap over a consecutive seven years after a severe drought
17 would approximate \$4.2 million/year.
 - 18 o This Rider E requirement would drop to \$2.2 million/year over six years if
19 the DCF cap was increased to +/- \$16 million.

20 In Appendix A to Board Order 2015-01 (pages 14-15), the Board approved the current
21 DCF caps of +/- \$8 million “as an acceptable balance between frequency of rider
22 applications and ability to handle material (drought) changes in hydro availability.” As
23 reviewed in the GRA Application (Appendix 3.4, Attachment 3.4.4) and in response to
24 YUB-YEC-1-47, Yukon Energy has provided updated information on the adequacy of the
25 existing DCF cap.

26
27 **(c)**

28
29 The question is unclear as to what is being assumed, or how the assumed net benefit of
30 \$4 million was derived. The assumed 25% of overall grid load to any one new customer
31 also exceeds any potential load scenario that YEC has considered to be relevant at this
32 time. Accordingly, YEC has insufficient information to assess what is being assumed.

1 As reviewed separately in past filings and in response to (a) and (b) above, YEC rates
2 are set based on LTA hydro availability. Short-term Rider E price charges per kW.h
3 related to water availability apply equally to all firm retail and industrial customers (i.e.,
4 these are not applied only to the new industrial customer) and are only expected under
5 severe drought conditions when the DCF is depleted to its minimum cap. The magnitude
6 and duration of such Rider E charges under such circumstances will be determined by
7 the Board at that time based on information then available to the Board and the duration
8 of the low water conditions. The purpose of such Rider E charges is to refill the DCF in a
9 fair and reasonable manner, and not to send price signals “to encourage conservation if
10 hydro is low or unavailable”.

11 The key assumptions in this question are that the DCF cap was at its maximum at year 0
12 (i.e., just before the new customer connected), that water is “low” (i.e., at least below
13 LTA) throughout the 10 years that the new customer is connected, and that the DCF is
14 at its minimum cap after 10 years when the new customer is disconnected.

15 In practice, review of available information (GRA Application, Appendix 3.4, Attachment
16 3.4.4) shows that low water conditions occurred in a limited number of the 35 years of
17 water record, and that depletion of the DCF cap appears to require a severe drought
18 sequence event. Concurrent with (or even in advance of) the most severe drought-year
19 event, for the 450 GW.h load examined in Attachment 3.4.4, a Rider E charge would be
20 required due to the DCF falling to the allowed minimum (DCF cap minimums of -\$8 and -
21 \$16 million were assessed).

22 In short, under the assumptions in this question, the available water record information
23 indicates that a new customer would likely be facing material Rider E charges within the
24 first five years of its operation and thereby contributing over the balance of its operating
25 life a large share of the funds required to enable the DCF to get back to the minimum
26 required amount. Absent the new large customer load, the remaining customers on the
27 grid would still face Rider E charges as required to refill the DCF without any contribution
28 from the new customer, i.e., it is possible that adverse impacts on other customers
29 would be reduced if the new customer was connected.

30 Actual impacts under each scenario (i.e., with and without the new customer) will
31 depend on the actual DCF cap then in place, the overall grid loads assumed, the actual
32 year-by-year water and fuel price conditions during the assumed 10-year period, and the
33 actual Rider E charges approved by the Board following a severe drought event.

- 1 As reviewed in Appendix A of Board Order 2015-01 (pages 14-15), the overall objectives
- 2 with the DCF cap determinations are to secure an acceptable balance between
- 3 frequency of Rider E applications (which are to be minimized) and ability to handle
- 4 material (drought) changes in hydro availability (the goal being to reduce Rider E charge
- 5 levels and duration needed under such water conditions).

1 **TOPIC: DCF ERA Appeal Decision**

2
3 **REFERENCE:**

4
5 “The Board’s decision was unreasonable. By interpreting “actual
6 diesel generation costs” for two rate stabilization mechanisms
7 differently, in an internally inconsistent manner, the Board set a rate
8 that prevents Yukon Energy from recovering diesel related costs it
9 actually incurred for generating the electricity sold to its wholesale
10 customer.”

11
12 *2017 YKCA 15 Yukon Energy Corporation v. Yukon (Utilities Board),*
13 *page 2*
14

15 **PREAMBLE:**

16
17 **QUESTION:**

18
19 a) Please confirm that YEC is of the opinion that the ERA must be allowed because
20 the DCF was allowed. Please discuss.

21
22 b) Please discuss that the corollary to (a). i.e. the DCF should not be allowed,
23 because the ERA was not allowed.
24

25 **ANSWER:**

26
27 **(a) and (b)**

28
29 Section 7 of OIC 1995/90, as reviewed in paragraph 17 of the Yukon Court of Appeal
30 judgement, directs the Board to fix rates of Yukon Energy for the wholesale customer
31 that are “...sufficient to enable Yukon Energy Corporation to recover its costs that are
32 not recovered from its other customers.” A mechanism such as the ERA is required
33 pursuant to this OIC at least to enable YEC to recover diesel related costs (including
34 related YEC payments required to be made into the DCF) it actually incurs for
35 generating the electricity sold to its wholesale customer.

1 The costs required for inclusion in the ERA are affected by the DCF. However, the DCF
2 was developed and approved to meet overall rate stabilization objectives for all Yukon
3 customers in response to likely annual hydro generation fluctuations related to water
4 availability. As shown in Board Order 2015-01, there is no apparent reasonable basis for
5 refusing to proceed with the DCF due to issues related to the ERA, i.e., the ERA
6 determinations must flow from GRA determinations (including adoption of LTA hydro
7 forecasts and the related DCF) and not vice versa.

1 **TOPIC: YECSIM Model**

2
3 **REFERENCE:**

4
5 “The structure of the YECSIM model was custom-made by KGS Group
6 to **take into account all significant factors that affect the operation**
7 **of the YEC power system** including complex rules of operation and
8 regulatory demands on YEC.”
9

10 *YEC response to AEY-YEC-1-1(b), ERA Part 1 Application*
11

12 **PREAMBLE:**

13
14 **QUESTION:**

- 15
16 a) Please confirm that YECSIM does not take into consideration instantaneous
17 demand or load location.
18
19 b) Please confirm that YEC believes instantaneous demand is not a significant factor
20 affecting the operation of the power system.
21
22 c) Please discuss response to (b). In your discussion, please include the following:
23 i. Please explain what is the maximum hydro generation capacity.
24 ii. Please explain how a load that is higher than the maximum hydro
25 generation capacity would be served with generation.
26
27 d) Please confirm that YEC believes load location is not a significant factor affecting
28 the operation of the power system.
29
30 e) Please discuss response to (d).
31
32 f) Please provide all costs that YEC has paid in relation to YECSIM since its
33 inception, by year and by party.
34
35 g) Other than YECSIM, has YEC considered the use of any hydro generation grid
36 software or is it aware of any such software, whether developed or conceptual? If

1 so, please list such software. If not, please discuss how KGS Group was selected
2 to provide YECSIM.

3

4 **ANSWER:**

5

6 **(a)**

7

8 YECSIM uses weekly duration curves to calculate peak loads within a week. For detailed
9 explanation please refer to Section 6.1.5 of the User Manual. YECSIM does not take into
10 consideration the load location.

11

12 **(b)**

13

14 Considering that YECSIM uses weekly duration curves to calculate peak loads within a
15 week, maximum weekly loads impact the model outputs.

16

17 **(c)**

18

19 The importance of maximum weekly loads is captured by using weekly duration curves as
20 discussed in the response to AEY-YEC-2-4(b).

21

22 **i.**

23

24 For the details on how the model calculates hydro generation please refer to
25 Sections 6.1.6 and 6.1.7 of the User Manual. Please note that the total discharge
26 through the power house is limited by technical and environmental constraints.

27

28 **ii.**

29

30 The load that is higher than the maximum hydro generation is served by thermal
31 generation. For the details please refer to Sections 6.1.11 to 6.1.15 of the User
32 Manual.

33

34 **(d)**

35

36 YECSIM does not take into consideration load location.

1 **(e)**

2
3 Considering the objective of the model and the fact that it is not intended to be a model
4 used for operational purposes, it is considered that adding the load location would not
5 materially improve the outputs. For the details on the objective of the model please refer
6 to Section 1.2 of the User Manual.

7
8 **(f)**

9
10 As previously described, the YECSIM model was developed by KGS Group Consulting
11 Engineers based in Winnipeg, MB. The cost to develop YECSIM over 2007 and 2008 was
12 \$370,000 (\$278,000 in 2007; balance in early 2008). Subsequently, KGS was consulted
13 periodically on specific issues with the models on various projects between 2009 and now.

14
15 **(g)**

16
17 YEC has been considering improving modelling capabilities by introducing other model(s).
18 At this point in time, the final decision has not been made on the particular model.

**City of Whitehorse
(CW)**

1 **TOPIC: 2017 Actual Results**

2
3 **REFERENCE:** ERA Two Part Filing, page 2-3

4
5 **PREAMBLE:** On page 2-3, YEC states:

6
7 **Revenue requirements:** Fuel and purchase power costs forecast of
8 \$2.381 million and \$2.407 million in 2017 and 2018 respectively,
9 including approval to assume that LTA thermal generation
10 requirements (separate from thermal generation maintenance activity
11 requirements) are supplied with a combination of 90% LNG and 10%
12 diesel generation.

13
14 CW requires information to understand the requested costs.

15
16 **QUESTION:**

- 17
18 a) Please provide a detailed analysis in Excel format that compares forecast 2017
19 costs to actual 2017 costs. In the response, please explain all variances.
20
21 b) Please provide a detailed analysis in Excel format of the 2017 actual thermal
22 generation, compared to the LTA with an explanation of all variances.
23
24 c) Please fully explain how the 2017 actual results would impact the 2018 forecast.
25

26 **ANSWER:**

27
28 **(a) and (b)**

29
30 Detailed analysis as requested is provided in Tables 1 to 3 and Attachment 1 to this
31 response. Table 1 and Table 2 provide the GRA Forecast [as filed in June 2017]¹; the

¹ Table 2.1, 2.2 and 3.2 in the GRA application filing provides the initial forecast sales, generation, LTA thermal, and forecast fuel costs (which included LTA firm thermal generation requirements plus forecast maintenance requirements, but excluded forecast capital thermal generation requirements).

1 updated forecast as provided in response to YUB-YEC-1-3² [filed September 22, 2017]
2 and preliminary actuals.

3 In order to properly respond to the impact on costs, YEC must first review changes in
4 generation. Table 1 below provides the prior sales and total generation forecasts for
5 2017 and preliminary actuals for 2017 (see UCG-YEC-2-28(a) for revised Table 2.1).
6 Overall firm sales are 5.5% higher than the updated forecast (21.55 GW.h), and firm
7 load generation is 4.8% higher the updated forecast. Firm wholesales account for 66%
8 of this sale increase, and industrial for 24%. Lower than expected winter temperatures
9 were an important factor for sales increases well above forecast. Overall losses at 8.1%
10 of sales were lower than the 8.8% forecast. Secondary sales were lower than forecast
11 due to Whitehorse hospital boiler maintenance and lower than expected water at Mayo.

² The response to YUB-YEC-1-3 [filed September 22, 2017] provided a revised Table 2.1 to reflect the AEY Compliance Firm Wholesale forecast for 2017 and related revised LTA thermal generation and fuel cost forecasts.

Table 1: Yukon Energy Sales & Total Generation - 2017
GRA Forecast, Updated Forecast, and Preliminary Actuals
[GRA Forecast as filed June 2017; Update as per YUB-YEC-1-3]

Line No.	Description	GRA Forecast	Updated Forecast	Preliminary Actuals
		2017	2017	2017
1	Sales (MW.h)			
2				
3	Residential	13,622	13,622	14,965
4	General Service	25,318	25,318	26,132
5	Industrial	38,219	38,219	43,419
6	Stree Lights	225	225	228
7	Space Lights	12	12	12
8				
9	Total Firm Retail & Industrial	77,395	77,395	84,756
10				
11	Firm Wholesale Sales	309,000	314,234	328,426
12				
13	Total Company-Firm	386,395	391,629	413,182
14				
15	Secondary Sales	11,464	11,464	8,385
16				
17	Total Company Sales	397,859	403,093	421,567
18				
19	Losses & Generation (MW.h)			
20	Losses - MWh	35,012	35,472	33,987
21	Losses - %	8.8%	8.8%	8.1%
22	Total Generation	432,871	438,565	455,554
23				
24	Secondary Sales Related Generation (incl. losses)	12,473	12,473	9,097
25				
26	Firm Load Generation	420,398	426,093	446,458

1. 2017 Preliminary Actuals are unaudited actuals based on preliminary results and subject to change.

2

3 Table 2 below provides the break out of generation by sources for prior forecasts and
4 preliminary actuals for 2017 (see UCG-YEC-2-39 for 2017 DCF Annual Report). In
5 addition to the increase in firm sales and required firm generation, the following factors
6 affecting actual generation in 2017 are noted:

7

- 8 • AEY Fish Lake hydro generation was below expected due to maintenance at one
- 9 of AEY's units.

- 1 • A combination of colder than expected weather and lower than expected water at
2 Mayo increased actual diesel and LNG generation more than might otherwise be
3 expected.
4
- 5 • Wind generation was well below expected due to the turbines being shut down
6 for the majority of the year due to required repairs.
7
- 8 • The DCF transfer was all LNG generation due to the high level of actual diesel
9 generation, i.e., the maximum allowed share of LNG was included in the
10 estimated preliminary DCF transfer per the GRA proposals in Appendix 3.4 of the
11 GRA. As a result, LNG share of final total LTA thermal generation was 86.5%
12 rather than 90% as assumed in the GRA forecasts.

Table 2: Yukon Energy Capital, Maintenance & Firm Generation - 2017

[GRA Forecast as filed June 2017; Update as per YUB-YEC-1-3]

Line No.	Description	GRA Forecast	Updated Forecast	Preliminary Actuals
		2017 MW.h	2017 MW.h	2017 MW.h
1	Firm Load Generation (YEC)	420,398	426,093	446,458
2	YECL Fish Lake Hydro	8,536	8,536	7,103
3	Total Grid ex. Secondary Sales	428,934	434,629	453,561
4				
5	Capital & RFID Generation			
6	Diesel	596	596	766
7	LNG	0	0	158
8	Total	596	596	924
9	Maintenance Generation			
10	Diesel	313	313	229
11	LNG	133	133	60
12	Total	446	446	288
13				
14	Actual Firm Generation Source (ex Capital, RFID and Maintenance)			
15	YECL Fish Lake	8,536	8,536	7,103
16	YEC Hydro	418,688	424,155	433,164
17	Wind	580	580	33
18	Diesel	113	136	3,623
19	LNG	1,017	1,222	9,638
20	Total	428,934	434,629	453,561
21				
22	LTA Generation (for firm sales)			
23	YECL Fish Lake	8,536	8,536	8,536
24	YEC Hydro	405,672	408,514	417,640
25	Wind	580	580	580
26	Thermal [see note]	14,146	16,999	26,806
27	Total LTA	428,934	434,629	453,561
28				
29	DCF Transfer (Thermal)			
30	Diesel	1,302	1,564	-
31	LNG [see note]	11,715	14,077	13,545
32	Total	13,016	15,641	13,545
33				
34	Mix of LTA Thermal Generation			
35	Diesel	1,415	1,700	3,623
36	LNG	12,732	15,299	23,183
37	Total	14,146	16,999	26,806

*Note: Line 26 determined based on DCF Term Sheet Table 3.4-1 in GRA.

Line 31 = 90% x Line 26-line 19, subject to limit that Line 31 cannot > line 32.

In summary, as shown in Table 2, expected LTA thermal generation was almost double the initial GRA forecast (26.8 GW.h actual versus 14.2 GW.h in the GRA forecast and 17.0 GW.h in the updated forecast) due to total firm grid generation load being 23.6

GW.h higher than forecast (453.6 GW.h actual versus 428.9 GW.h forecast). The increased firm grid load was mainly the result of lower than normal winter temperature in the latter part of 2017. Due to the high levels of actual diesel generation, in part reflecting lower than expected water at Mayo, the DCF transfer is 100% LNG and the final LTA fuel mix for 2017 is 86.5% LNG and 13.5% diesel.

Forecast 2017 costs (GRA) are compared to preliminary actual 2017 costs for fuel and purchase power as provided in Table 3 below. The fuel costs include LTA thermal generation plus maintenance fuel requirements (see Table 2), and assume fuel prices and efficiencies as per the GRA forecasts (actual diesel generation fuel costs reflect actual mix of plant generation sources).

Table 3: YEC Fuel & Purchase Power Costs for 2017
[GRA Forecast as filed June 2017]

(\$000)	Proposed 2017 GRA	Preliminary 2017 Actuals
Fuel (Actual generation - firm Load & Maintenance)		
Diesel	\$ 112	\$ 988
LNG	\$ 169	\$ 1,422
Total	\$ 281	\$ 2,411
DCF Transfer		
Diesel	343	0
LNG	1,718	1,987
Total	2,061	1,987
Purchased Power	39	49
Total Fuel and Purchased Power	\$ 2,381	\$ 4,446

1. 2017 Preliminary Actuals are unaudited actuals based on preliminary results and subject to change.

The above tables are provided in excel format as CW-YEC-2-1(a and b) Attachment 1. It is noted that 2017 Preliminary Actuals are unaudited actuals based on preliminary results and subject to change.

1 **(c)**

2

3 2017 actual thermal generation results do not impact 2018 thermal generation forecasts.

4 However, 2017 actual water/snow levels would impact 2018 forecasts.

1 **TOPIC: Update to the DCF and LTA**

2
3 **REFERENCE:** ERA Two Part Filing, page 2-4

4
5 **PREAMBLE:** On page 2-4, YEC states:

6
7 **Update to the DCF and LTA:** Approval of Yukon Energy's Revised
8 DCF Term Sheet provided in Attachment 3.4-1 of Appendix 3.4 of the
9 GRA necessary for determination of annual expected LTA hydro and
10 thermal generation requirements and fuel costs, including proposed
11 updates to the DCF for the following:

- 12 o Updated table for "Expected YEC Thermal; Generation with
- 13 LTA YEC Hydro Generation" to reflect updated information on
- 14 LTA wind and hydro generation (YEC and AEY); and
- 15 o Updates for incorporating LNG fuel and generation
- 16 facilities into DCF cost determinations.

17
18 Appendix 3.4 of the GRA also provided updates on the following:

- 19
- 20 o Potential Thermal Generation Variability (GW.h/yr) Depending
- 21 on Water Conditions (35 years) – Range of Grid Loads from 380
- 22 to 450 GW.h/yr (Attachment 3.4.2);
- 23 o Information on YECSIM Model (Attachment 3.4.3); and
- 24 o DCF Cap Option Assessment (Attachment 3.4.4).

25 No proposal regarding the Rate Schedule 42 ERA was provided in the
26 2017-18 GRA application as the ERA was at that time the subject of an
27 appeal to the Court from Board Order 2015-06. Yukon Energy noted
28 that at such time as the Court's decision is provided, it would review the
29 ERA and provide the Board with a filing on this matter. Subsequent to
30 the Court of Appeal judgment in September 2017, and after receiving
31 comments from parties in the GRA proceeding, the Board issued Order
32 2017-08 on October 18, 2017:

- 33 • Part 1 of this ERA Application addresses the outstanding
- 34 matters with regard to the ERA prior to 2017, including a
- 35 proposed amended Rate Schedule 42 wholesale rate effective
- 36 January 1, 2012; and

- Appendix 2.2 of this ERA Application provides the short-term (“ST”) hydro-electric alternative GRA forecast (the “ST Alternative GRA Forecast”) for the test period as directed in Board Order 2017-08 so that this alternative can be included in the Part 2 assessments as directed by this same Board Order.

QUESTION:

- a) Please confirm that the only changes to the GRA are discussed in the last to bullets of the referenced quote. If not confirmed, please fully explain all changes proposed for the GRA.

ANSWER:

(a)

Yukon Energy is not proposing changes to the GRA as filed in June 2017. Specifically, Yukon Energy is continuing to seek Board approval of a revenue requirement based on LTA hydro generation forecasts.

The referenced quote summarizes YEC’s current GRA as filed in June 2017, which has not been changed. The last part of the referenced quote reviews ERA related matters, noting why no proposal on the ERA was included in the GRA filing, and reviewing subsequent events regarding the Court decision and the ERA Application.

The information discussed in the last two bullets noted above relate to information the Board directed Yukon Energy to file pursuant to Board Order 2017-08. With regard to the first bullet, the Part 1 ERA Application is being addressed via a separate written process as directed in Order 2018-01. With regard to the second bullet, the Board in Order 2017-08 directed Yukon Energy to provide an alternative forecast revenue requirement for YEC’s 2017-18 General Rate Application using a short-term hydro-electric forecast for the test period and noting any consequent changes to the thermal generation forecast, removing any DCF references in that alternative forecast. Appendix 2.2 of the Two Part ERA Application was provided to comply with this Board direction, so that this alternative can be included in the assessments for the period 2017 forward as part of the current GRA process. However, Yukon Energy has not altered the requested approvals outlined in its Application filed in June 2017.

1 **TOPIC:** Outcomes and Concerns

2
3 **REFERENCE:** ERA Two Part Filing, page 2-5

4
5 **PREAMBLE:** On page 2-5, YEC states:

6
7 In summary, the Board in Order 2015-01 and Order 2015-06
8 confirmed the need for a mechanism that effectively protects
9 ratepayers from thermal generation cost impacts caused by
10 fluctuation of hydro generation due to water conditions or
11 changes in wind conditions, the use of LTA hydro forecasts for
12 the 2012-13 GRA, the need for and justification of the DCF as
13 currently modified, and the use of the YECSIM model to
14 determine the 2012-13 GRA LTA hydro forecasts and DCF
15 Term Sheet table determinations. YEC's 2017-18 GRA
16 reflected these prior Board decisions with the proposed LTA
17 hydro forecasts and updated DCF mechanisms based on the
18 updated YECSIM model.

19
20 **QUESTION:**

- 21
22 a) Please provide references to the specific place/s in Board Orders 2015-01 and
23 2015-06 or the Appendices thereto where the Board required the specific solution
24 recommended by YEC.
- 25 b) Please confirm that the proposed DCF term sheet, using the LTA only recovers
26 actual out of pocket costs of YEC, and does not in any way contribute to additional
27 earnings of YEC. If not confirmed, please provide a detailed analysis of all
28 incremental earnings.

29
30 **ANSWER:**

31
32 **(a)**

33
34 Board Order 2015-01 approved the DCF subject to the directions set out in the Reasons
35 for Decision (Appendix A of the Order), and directed YEC to commence quarterly reports
36 regarding the balance in the DCF account effective March 31, 2015.

1 Appendix A of Board Order 2015-01 noted as follows in this regard:

- 2 • With regard to need for a mechanism that effectively protects ratepayers from
3 thermal generation cost impacts caused by fluctuation of hydro generation due to
4 water conditions, the Board stated as follows:

5 “The Board notes that all Parties to this proceeding agree that there is a
6 need for a mechanism that effectively protects ratepayers from diesel
7 generation cost impacts caused by fluctuation of hydro generation due to
8 water conditions or changes in wind conditions. The question before the
9 Board is: How is this best accomplished?” [Page 11, omits footnotes]

10 In this regard the Board also noted as follows:

11 “Therefore, although the Board has noted the other parties concerns
12 regarding the YECSIM model, and is aware that the YECSIM model has
13 not been tested before the Board, the Board accepts the DCF as proposed
14 by YEC because it is a fund for customers to smooth rate impacts for those
15 occasions when hydro generation is less than LTA or to build up the fund
16 when hydro generation is greater than LTA. The Board approves the DCF
17 as proposed by YEC. However, the Board directs that the DCF fund is to
18 be used only for variations from LTA water availability. Any application to
19 utilize the fund in some other fashion will require the closing of the fund,
20 the refunding of any balances to customers, and the direction for YEC to
21 use short-term forecasts for its hydro generation for future GRAs.” [Page
22 14, omits footnotes].

- 23 • With regard to use of LTA hydro generation, the Board noted that it “has previously
24 accepted LTA hydro generation as the basis for YEC GRA forecasts.” [Page 14,
25 omits footnotes].
- 26 • With regard to the use of the YECSIM model to determine the 2012-13 GRA LTA
27 forecasts and the DCF Term Sheet table determinations, the Board also noted that
28 “the 2012-13 LTA forecast was provided by means of YEC’s YECSIM model and
29 was not contested at that time. Moreover, no evidence has been presented in this
30 proceeding that the YECSIM model does not operate as it is intended, or that there
31 would be any harm to customers if the model is used in a consistent fashion for
32 DCF purposes.” [Page 14].

1 In Appendix A of Order 2015-06 the Board noted that it “approved the DCF as proposed
2 by YEC including the DCF cap of +/- \$8 million.” [Page 4, omits footnote referencing Board
3 Order 2015-01, Page 15].

4 In Appendix A of Order 2015-06 the Board also noted as follows regarding the requested
5 approvals related to the DCF [Page 10]:

- 6 • “The Board approves the Revised DCF Term Sheet as set out in Attachment 1 of
7 YEC’s April 7, 2015 Compliance Application.”
- 8 • “The Board approves the DCF amounts as provided in Table A1 of Appendix A for
9 2012 and 2013 as final and for 2014 as preliminary.”
- 10 • “The Board approves a DCF Rider rate schedule (Rider E) as shown in response
11 to YUB-YEC-1-006, Table 1, applied to consumption effective September 1, 2015
12 and until or on March 31, 2016, with a rebate of 0.68 cents/kW.h for all firm kW.h
13 retail and major industrial sales in Yukon of YEC and YECL.”

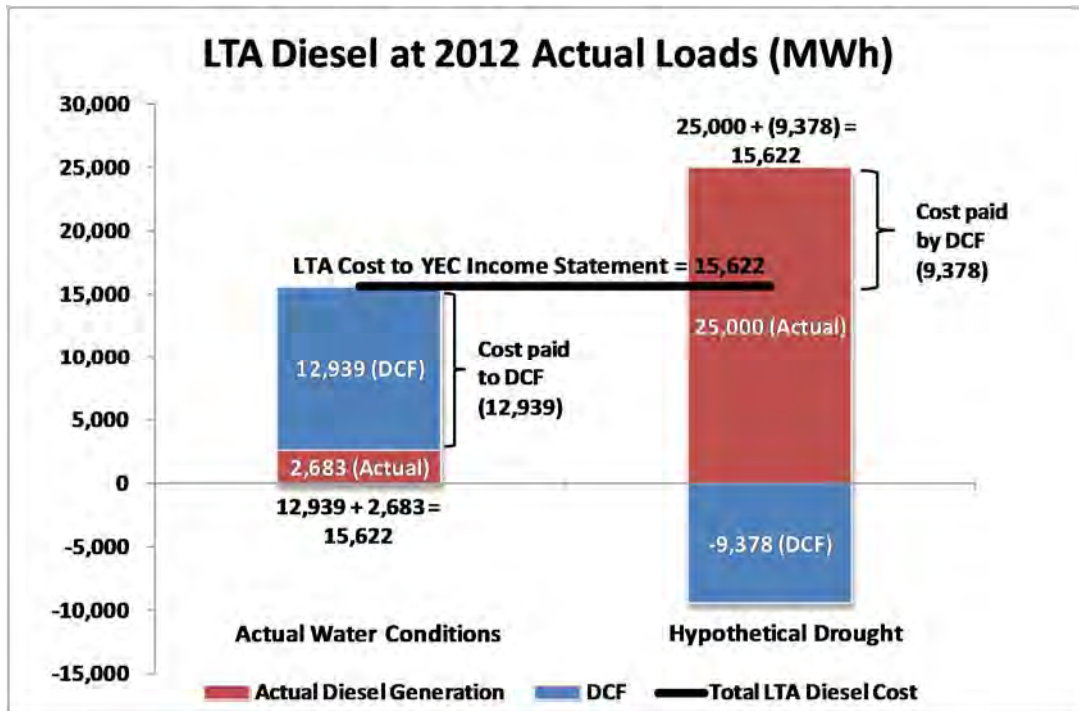
14 **(b)**
15

16 The proposed DCF Term Sheet, using the LTA, results in YEC’s costs for thermal
17 generation being based on LTA hydro generation (per the approved DCF Term Sheet
18 table) as applicable to the actual firm grid load each year. As a result, YEC does not secure
19 additional earnings when water conditions are better than LTA, and YEC’s earnings are
20 not reduced when water conditions are worse than LTA.

21 This principle is summarized in Figure 1 below. Figure 1 sets out LTA diesel generation
22 for 2012 based on 2012 actual total generation. It demonstrates that the LTA diesel
23 generation and cost to YEC remain unchanged, even when water conditions are changed
24 from the actual 2012 water conditions, or actual diesel generation operated by YEC (net
25 of capital projects and RFID diesel generation) vary based on water conditions.

1

Figure 1: LTA Diesel at 2012 Actual Loads (MW.h)



2

3 In summary, although payments into or out of the DCF fund in any year can potentially be
 4 affected by items other than changes in forecast water levels (including activities such as
 5 enhancing winter storage and changes due to actual system operations), such items do
 6 not affect the final LTA diesel generation amount for the year (as estimated using the
 7 approved DCF Term Sheet and the total actual generation load for the year) – and
 8 therefore such items do not affect YEC earnings.

1 **TOPIC: Risks**

2
3 **REFERENCE:** ERA Two Part Filing, page 2-13

4
5 **PREAMBLE:** On page 2-13, YEC states:

6
7 Considerable separate risk is related to water conditions, i.e., there is
8 the potential material risk that water conditions will deteriorate, and very
9 little possibility that water conditions could be better than assumed in
10 the ST forecast for the 2017-18 GRA.

11
12 **QUESTION:**

13
14 a) Please provide all analysis or research in support of the statement: "Considerable
15 separate risk is related to water conditions."

16
17 **ANSWER:**

18
19 **(a)**

20
21 No specific analysis or additional research has been undertaken in support of this specific
22 statement outside of analysis and assessments included in the 2017/18 GRA [see
23 Appendix 3.4, and specifically detailed assessments provided in Attachment 3.4.2 and
24 Attachment 3.4.4] and in the Two Part ERA Application.

25 With regard to the specific statement noted, please see response to YUB-YEC-2-15 which
26 also reviews the limitations in this regard of a ST hydro forecast and the forecast included
27 in Appendix 2.2 of the Two Part ERA Application.

1 **TOPIC: ST Forecasts**

2

3 **REFERENCE:** ERA Two Part Filing, page A2.2-2

4

5 **PREAMBLE:** On page A2.2-2, YEC states that the ST forecast was not prepared for
6 the purpose of setting GRA revenue requirement.

7 **QUESTION:**

8

9 a) Please fully explain the purpose of the ST forecast, and what it is used for.

10

11 **ANSWER:**

12

13 **(a)**

14

15 Short-term thermal forecasts are used by YEC for operational purposes and to assist with
16 financial planning. Operations uses it by assessing water availability and forecast loads to
17 determine the need for thermal and the optimal allocation of generation sourcing. Finance
18 uses the short-term thermal forecasts to determine the expected short-term fuel costs for
19 forecasting cash flows.

1 **TOPIC:** YECSIM MODEL

2
3 **REFERENCE:** ERA Two Part Filing, page 2.4-1

4
5 **PREAMBLE:** On page 2.4-1, YEC states:

- 6
7 1) **Constraints** - In the case of YECSIM, constraints are related to
8 the physical state of the system, such as maximum and
9 minimum lake elevations, storage elevation curves of the lakes,
10 and physical characteristics of power generation plants.
11 Constraints are also related to environmental requirements such
12 as, for example, minimum fish flows and meeting the electricity
13 load.

14
15 **QUESTION:**

- 16
17 a) Please provide list of all constraints considered in the development of the model.
18 In the response, please fully discuss each constraint, including the limiting factors
19 for each constraint, the maximum or minimum value for each constraint, and any
20 operating policy limits that may be different than the physical limit. As an
21 example, discuss whether YEC has an operating policy for minimum reservoir
22 levels that may be different than the physical limit, which may be different than
23 the engineering design limit.
24
25 b) Please fully discuss how the YECSIM model accounts for any systematic biases
26 in data and models arising from using an LTA that may occur as a result of things
27 such as climate change. As an example, if climate change is impacting weather,
28 and water levels, how has the YECSIM model been designed to account for such
29 biases?

30
31 **ANSWER:**

32
33 **(a)**

34
35 For details on the model constraints, operating policies and rules that supersede the
36 physical limits please refer to Sections 6.1.1 to 6.1.16 of the User Manual inclusive, as
37 well as Appendices D and E of the User Manual.

1 For example, physical limits of elevations in the lakes are superseded by min/max
2 elevations prescribed in water use licenses that are presented in Appendix E.

3
4 **(b)**

5
6 The model uses the input data provided by the user. The model neither creates nor
7 modifies the input data, such as, for example, inflows to the lakes or loads. To eliminate
8 potential biases arising from the potentially inadequate input data, such as for example
9 climate change impact on the inflows to the lakes, the input data need to be addressed.

10 No changes to the model inputs have been made with regard to climate change, given
11 the lack of any clear basis for undertaking specific changes. Climate change impacts are
12 understood to involve long timelines. As such, these impacts will not affect GRA test
13 year assessments.

1 **TOPIC: Risks**

2
3 **REFERENCE:** Table A2.1-1

4
5 **PREAMBLE:** In Table A2.1-1, YEC discusses the allocation of traditional sharing of
6 regulatory risk for diesel generation.

7
8 **QUESTION:**

9
10 a) Please fully discuss each risk, and how the allocation of risk may have changed
11 as a result of Part 2 of this application.

12
13 b) Please fully discuss each risk, and how the total level of risk may have changed
14 as a result of Part 2 of this application.

15
16 **ANSWER:**

17
18 **(a) and (b)**

19
20 Please see response to AEY-YEC-2-1 for discussion of specific risks noted in this table.

21 As reviewed in response to CW-YEC-2-2, YEC has not changed its GRA as filed in June
22 2017. The ERA Application, Part 2, addresses matters as directed by the Board in Order
23 2017-08, including the provision of a ST Alternative GRA Forecast. The implications of
24 adopting a ST versus LTA GRA forecast are addressed in the ERA Application, including
25 the increased risk of rate instability related to water variability.

26 In the final analysis, the ERA Application notes that thermal generation cost risks related
27 to water variability continue to be borne by ratepayers rather than the utility, regardless
28 as to whether a ST or LTA forecast is adopted for GRA purposes, and the appropriate
29 contingency fund mechanisms are required in either event (see Figure 2-1, page 2-8 of
30 ERA Application).

1 **TOPIC: Portable Diesel Generators**

2
3 **REFERENCE:**

4
5 **PREAMBLE:** The City of Whitehorse is aware of four trailers that appear to house
6 diesel turbines. The City of Whitehorse also is aware of external fuel
7 tanks. Late last fall, the City of Whitehorse received notification from
8 YEC that due to water levels at Mayo dam, that Secondary Power sales
9 were immediately ended, including the system at the City's multiplex
10 which has secondary power system controlled by YEC's SCADA
11 system. The City of Whitehorse requires information to assess the
12 facilities.
13

14 **QUESTION:**

- 15
16 a) Please provide a full explanation of the facilities referred to in the preamble. In the
17 response, please provide references to the initial approvals for the facilities and
18 any updates to the facilities. In the response please indicate if the facilities are
19 permanent or temporary, and discuss the long term strategy for the facilities.
20
21 b) Please provide a full analysis of the use of the generation from the facilities for
22 2014, 2015, 2016, 2017 and forecast for 2018. In the response, please indicate
23 the portion of the supply from these facilities used to supply communities and
24 customers north of Whitehorse, such as Stewart, Pelly and Dawson as well as the
25 City of Whitehorse, in arriving at total generation.
26

27 **ANSWER:**

28
29 **(a)**

30
31 There are four 2 MW diesel rental units installed at the Whitehorse Rapids generating
32 facility. These units were installed in late November 2017 to provide 8 MW of additional
33 short-term dependable capacity in response to the forecast dependable capacity shortfall
34 of 7.6 MW for 2017 (see GRA, page 2-15).

35 Each trailer mounted generator has an associated pad mount transformer with cabling
36 from the generator to the transformer and from the transformer to the S150 substation.

1 Fuel is supplied from a common 61,000 liter tank. There is a separate station service
2 supply to each unit for heat and ancillary supply.

3 The rental units are temporary. YEC currently plans to use mobile diesel units again for
4 the winter of 2018-19, at which time the Third LNG Engine will also provide added
5 permanent dependable capacity for the Yukon Integrated System.

6

7 **(b)**

8

9 The rental installation was not completed until December 2017. There has been no
10 generation of the rentals from installation until the end of February 2018 other than
11 monthly run-ups for maintenance.

12 If the rental units were used for generation, YEC would not be able to estimate the portion
13 supplied to specific communities as Yukon is an integrated grid.

John Maissan
(JM)

TOPIC: Section 1 Introduction

REFERENCE: Page 1-3 L20-26 Re. YDC Contributions "...with \$18.3 million used to offset the capital costs of the Whitehorse Diesel Natural-Gas Conversion Project (LNG Project) added to rate base in 2015..."
And CBC radio media coverage on March 13 at approximately 7:20 AM in which Mr. Brad Cathers (the then Minister responsible for the Yukon Development Corporation and the Yukon Energy Corporation) is heard to say that the \$18.3 million was YDC's equity contribution to the LNG project as the Yukon Utilities Board requires Yukon Energy to have a 60:40 debt equity ratio.

QUESTION:

- a) Was the \$18.3 million given to YEC by YDC intended to be YEC's equity portion of the project?
- b) If so, does the balance of the LNG Project costs of \$23.633 million (\$41.933 million less \$18.3 million) attract debt cost only as opposed to a mixture of debt and equity?
- c) If the answer to (a) is no, please explain the apparent discrepancy between the referenced two pieces of information and provide documentation to support YEC's position.

ANSWER:

(a) (b) and (c)

No. The \$18.3 million given to YEC by YDC was not intended to be YEC's equity portion of the project. YEC received \$22.4 million of construction financing that was converted to a capital contribution, with \$18.3 million of this specified as the capital contribution allocated to the LNG plant. The balance was added to utility rate base and therefore attracts debt and equity in accordance with approved capital policy.

YEC cannot comment on the media reports.

1 **TOPIC:** **Section 2 Sales and Generation**

2
3 **REFERENCE:** Various media coverage involving contact with YEC, has indicated that
4 YEC is experiencing lower than long term average (LTA) water flows
5 available for generation due to low water levels in Mayo Lake.
6

7 **PREAMBLE:**

8
9 **QUESTION:**

- 10
11 a) What flow volume and generation is available from the Mayo Hydro system this
12 2017-2018 winter and what are the long term winter averages for this system?
13
14 b) Are the flows and generation available from Whitehorse Rapids and the Aishihik
15 generating stations this winter at LTAs?
16
17 c) If not, please provide the actual flow and generation available from these two
18 plants and what are the LTAs?
19
20 d) Please provide a forecast for the winter of 2017-2018 (assuming spring flows will
21 be at LTA) of the shortfall in hydro generation (requiring additional thermal
22 generation) compared to LTA.
23
24 e) What will this the cost of this generation be, and will this come out of the DCF?

25
26 **ANSWER:**

27
28 **(a), (b) and (c)**

29
30 The current analysis uses actual flows measured at the YEC hydro facilities.¹

31 Table 1 presents, for each of the three hydro facilities, a comparison of actual average
32 flows for the 2017-2018 winter (assumed to be November to March) and LTA flows

¹ At this time, reservoir level and flow data from Water Survey of Canada for 2017 and 2018 used to calculate inflows are not available. Consequently, the response uses actual flow records measured at the YEC hydro generating stations and are presented for illustration purposes.

obtained from YECSIM as per the GRA with total generation adjusted to match the actual production observed over the same period.

Table 1. Comparison of Actual & LTA Flows: YEC Hydro Facilities: Winter 2017-18

Hydro Facility (Nov-March)	Actual Avg. Flows [m ³ /s]	LTA Avg. Flows [m ³ /s]
Mayo	12.26	24.72
Aishihik	18.37	18.20
Whitehorse	155.14	137.15

Table 2 presents, for each of the three hydro facilities, a comparison of actual generation for the 2017-2018 winter and LTA hydro generation obtained from YECSIM.

Table 2. Comparison of Actual & LTA Hydro Generation: Winter 2017-18

Hydro Facility (Nov-March)	Actual Hydro Generation [GWh]	LTA Hydro Generation [GWh]
Mayo	18.37	31.64
Aishihik	105.75	86.20
Whitehorse	86.08	88.31

A higher Aishihik Lake level at the beginning of the winter period allowed YEC to generate more power out of Aishihik GS to deal with higher than forecasted loads and to compensate for the low water conditions at Mayo GS.

In comparison, Marsh Lake levels at the start of the winter were lower than long-term average. Higher generation at the beginning of the winter period out of Whitehorse GS was also required to meet the greater loads and to compensate for the low water conditions at Mayo GS. The higher generation combined with water levels falling below historical range led YEC to reduce generation in the latter part of the winter at Whitehorse GS. Consequently, actual hydro generation out of Whitehorse GS is slightly less than LTA hydro generation calculated by YECSIM for a similar grid load.

1 **(d) and (e)**

2

3 The response above provides actual generation for the winter of 2017-2018 – there is no
4 basis for providing the requested forecast for this same winter assuming spring flows at
5 LTA.

6 Please see response to JM-YEC-2-3 regarding ST hydro forecast updates for 2018. YEC
7 costs for thermal generation fuel for 2018 will be determined by LTA as at year end, and
8 will not be affected by actual water conditions and hydro generation.

1 **TOPIC: Short-term Hydro Alternative GRA Forecast (Appendix 2.2 to two-**
2 **part ERA application December 6, 2017)**

3
4 **REFERENCE:** Page A-2.2-1

5
6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Given the below LTA hydro experienced so far this winter, would the ST hydro
11 forecast be any different if it was being run today compared to when it was run for
12 this application?
13

14 **ANSWER:**

15
16 **(a)**

17
18 A ST hydro forecast for 2018 run today, based on reservoir levels last November, yields
19 lower forecast thermal generation for 2018 than was forecast for the December 2017 ERA
20 Application. Each forecast excludes thermal generation for capital and unit maintenance.
21

22 The ST hydro and thermal generation forecast for 2018, as filed in the December 2017
23 ERA Application, was prepared based on actual reservoir levels as at Nov 29, 2016 and
24 assumed LTA inflows thereafter, assuming GRA forecast loads and wind generation at
25 approximately 0.5 GW.h/year. The 2018 forecast was the second year in the ST
26 assessment, and reflected lower reservoir levels forecast for November 2017 based on
27 LTA inflows and the forecast grid load. The resulting initial ST thermal generation forecast
28 for 2018 was 8,226 MW.h.
29

30 An updated ST hydro and thermal generation forecast for 2018 has been prepared based
31 on actual reservoir levels as at Nov. 19, 2017 and assumed LTA inflows thereafter, as well
32 as GRA forecast loads and wind generation at approximately 0.5 GW.h/year. The resulting
33 updated ST thermal generation forecast for 2018 is 2,795 MW.h. It is much lower than the
34 earlier ST forecast for 2018, reflecting that 2018 is now the first year in the ST forecast.

- 1 The difference between the 2018 forecast resulting from second year of simulation (8,226
2 MWh) vs 2018 run with updated water information and as first year of the simulation (2,795
3 MWh) is caused by two factors:
4
- 5 1) Higher initial water levels – actual water levels were higher than forecast in the 2
6 year simulation; and
7
 - 8 2) When run as the first year of a simulation, the model more aggressively dispatches
9 hydro resources, thereby reducing the thermal requirement.

1 **TOPIC:** **Short-term Hydro Alternative GRA Forecast (Appendix 2.2 to two-**
2 **part ERA application December 6, 2017)**

3
4 **REFERENCE:** Page A2.2-3 top bullets re diesel-LNG allocation

5
6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Whether LTA or ST hydro is assumed for forecasting thermal generation
11 requirements, the actual thermal requirements in any year will be the same. How
12 then can actual LNG-diesel allocation be 60:40 with ST forecasting and 90:10
13 when using LTA forecasting?

14
15 b) Why would the actual operational practice of running LNG or diesel be any
16 different if the actual requirement is the same (the forecast method cannot
17 change the actual hydro availability)?

18
19 **ANSWER:**

20
21 **(a) and (b)**

22
23 The LTA and ST forecasts address totally different time periods for assessing the LNG-
24 diesel allocation. As a result, the allocations used for LTA forecasts differ materially from
25 the allocations used for ST forecasts. The forecast related to diesel or LNG usage will
26 change depending on whether a short term or a long term average perspective is taken.
27 Overall, the forecast for 2017/18 and high water provide a solid basis for a ST LNG:
28 diesel split that is very different than the LTA LNG: diesel split for the same load.

29 As noted in the ERA Two Part Application, Appendix 2.2, page A2.3-3, the 60/40
30 LNG/diesel allocation of forecast short term generation specifically for expected
31 favourable water conditions in the 2017 and 2018 test years reflects the tendency for

1 diesel generation to dominate smaller and shorter duration thermal generation¹, and the
2 lack of any useful additional assessments as to a forecast allocation for each test year.

3 In contrast, the 90/10 LNG/diesel allocation for LTA forecast thermal reflects an
4 assessment that considers a long term perspective over all 35 water years; it
5 acknowledges that some years will have below average water levels and that the
6 majority of thermal generation would occur within these years; while other years will
7 have minimal thermal generation, e.g., at grid load of 420 GWh/year 75% of thermal
8 generation requirement over 35 years would occur in 20% of the water years and less
9 than 1% of this thermal generation would occur in 46% of water years. The basis for the
10 90/10 LNG/diesel allocation for LTA generation was reviewed in detail in Appendix 3.4 of
11 the 2017/18 GRA Application and in the following IR responses: YUB-YEC-1-25;
12 JM-YEC-1-13; YUB-YEC-1-42; YUB-YEC-1-43; YUB-YEC-1-36 and YUB-YEC-1-39.

13 Please also see response to YUB-YEC-2-19 and YUB-YEC-2-21.

¹ Please see YUB-YEC-2-6 ((c) at page 5) and YUB-YEC-1-38 for review of information from Appendix 3.4 of the GRA on the tendency for diesel generation to dominate smaller and shorter duration thermal generation requirements under these forecast test year conditions.

1 **TOPIC:** **Short-term Hydro Alternative GRA Forecast (Appendix 2.2 to two-**
2 **part ERA application December 6, 2017)**

3
4 **REFERENCE:** Page A2.2-5 Item 3b

5
6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Is this section essentially saying that rates will be more volatile using a ST
11 forecasting method; i.e. they will vary with water availability?

12
13 b) Does YEC have a preference for one forecasting method or the other?

14
15 **ANSWER:**

16
17 **(a) and (b)**

18
19 Yes. Appendix 2.2 notes that the Board has previously approved LTA hydro forecasts as
20 the basis for setting revenue requirements in order to provide greater long-term rate
21 stability for ratepayers than is provided by ST hydro forecasts. Specifically, short-term
22 hydro forecasts for the current test years reflect current very favourable water conditions
23 and would move rates below the LTA revenue requirement levels required for long term
24 rate stability for ratepayers. Please see response to YUB-YEC-2-3(c) for review of
25 history regarding ST versus LTA forecast use in the 1990s, and YUB-YEC-2-12
26 regarding the ST alternative in the current proceeding. Related impact issues regarding
27 the DCF cap are addressed in response to YUB-YEC-2-11(c and d).

28 Yukon Energy supports use of long term average generation forecasts that provide for
29 greater rate stability over time.

1 **TOPIC: YECSIM Model**

2
3 **REFERENCE:** At the YECSIM workshop February 12, 2018 it was explained that
4 YECSIM could not model the benefits of the diurnal variations in
5 intermittent energy supply options such as solar PV and wind power.
6 Solar power only being available in the day time when electrical loads
7 are higher and wind power which is higher in the afternoons when
8 electrical loads are higher and lower in early mornings when electrical
9 loads are typically lower.

10
11 **PREAMBLE:**

12
13 **QUESTION:**

- 14
15 a) Please describe how YEC would or does assess the added value of such beneficial
16 diurnal patterns when assessing such supply options.
17
18 b) Can the YESIM [sic] model adequately assess the value of uprates to the existing
19 hydro plants and changes to the storage ranges of hydro reservoirs?
20
21 c) Can the YECSIM model adequately assess smaller run-of-river hydro plants that
22 may be considered in future?
23
24 d) When YEC installs the proposed short-term battery energy storage project,
25 would/could the YECSIM model be updated to include it being operated as
26 intended?
27

28 **ANSWER:**

29
30 **(a)**

31
32 Considering that YECSIM provides outputs at the weekly time step, YECSIM has not been
33 designed to address diurnal patterns of intermittent resources. YECSIM can introduce
34 intermittent resources as averaged non-dispatchable resources. The nuances of diurnal
35 variations of those resources are lost in the averaging though.

1 **(b)**

2
3 Yes.

4
5 **(c)**

6
7 To adequately assess run-of-river hydro plants YECSIM will need to be adapted.

8
9 **(d)**

10
11 If YEC installs the proposed energy storage, YEC will assess the modelling needs and
12 either upgrade YECSIM or introduce a more advanced model to address the impact
13 caused by the energy storage.

Utilities Consumers' Group (UCG)

1 **TOPIC:**

2
3 **REFERENCE:** *Reference: YECSIM Model in GRA Presentation, February 12, 2018,*
4 *page 5“Water-Related & Thermal Generation Forecasts”*

5
6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Please explain how the YECSIM model incorporates the benefits of other
11 renewable sources of generation like solar and options such as battery storage.

12
13 b) If the YECSIM model does not include the benefits of solar generation, please
14 explain how the model can be updated.

15
16 **ANSWER:**

17
18 **(a)**

19
20 Considering the weekly time step YECSIM provides outputs for, YECSIM is not specifically
21 designed to incorporate intermittent resources, such as solar and wind, that can vary their
22 generation within a day or week. However, YECSIM can incorporate intermittent resources
23 such as solar and wind by averaging them over the time step and considering them as
24 non-dispatchable resources. The daily and weekly variations of those resources are lost
25 in the averaging.

26
27 YECSIM has not been designed to incorporate battery storage.

28
29 See also response to JM-YEC-2-6.

30
31 **(b)**

32
33 A model with a higher resolution in terms of the time step would be more beneficial to
34 address intermittent resources such as solar.

1 **TOPIC:**

2
3 **REFERENCE:** YECSIM Model in GRA Presentation, February 12, 2018, page
4 **6** *“Change in water from GRA forecast is a ratepayer risk”*
5

6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Please explain why YEC does not accept any of the forecast risk related to hydro
11 generation to ensure that YEC is motivated to optimize its forecast model and the
12 use of generation assets.
13

14 **ANSWER:**

15
16 **(a)**

17
18 Based on normal regulatory principles, risks related to water variance are not borne by the
19 utility.
20

21 Please see response to YUB-YEC-2-2(c) for detailed review of relevant GRA filings and
22 Board Orders regarding the principle that risk of low water conditions variance relative to
23 GRA forecasts, as regards added cost of thermal generation, is borne by customers of the
24 utility. See response to YUB-YEC-2-9(e) and YUB-YEC-2-31(c) and (d) regarding
25 contingency fund approaches used with regard to water-related hydro generation
26 variances in other Canadian jurisdictions.

1 **TOPIC:**

2
3 **REFERENCE:** YECSIM Model in GRA Presentation, February 12, 2018, page 8
4 *“Regardless of forecast used, need consistent implementation in*
5 *GRA and for determining diesel generation costs at each year*
6 *end.”*

7
8 December 18, 2017 Alternative GRA Forecast Submission, page 3
9 *“The current level of existing firm rates result in a \$3.320 million*
10 *rate revenue shortfall in 2017, and a \$5.881 million rate revenue*
11 *shortfall in 2018 compared to revenue requirements set out in Tab*
12 *3. These shortfalls, which are outlined in Table 1 below, form the*
13 *basis for the proposed rate increases in this Application.”*

14
15 **PREAMBLE:**

16
17 **QUESTION:**

- 18
19 a) Please confirm that, from YEC’s perspective, it doesn’t actually matter whether you
20 use a short-term forecast or a long-term average forecast as long as there is
21 consistency with forecast and year-end reconciliations.
22
23 b) Please confirm that the forecast revenue shortfalls have been reduced by \$2.03
24 million and \$0.7 million in 2017 and 2018 respectively as a result of using the short-
25 term hydro generation forecast.
26
27 c) Please provide specific details of all costs that have been reduced as a result of
28 using the short-term hydro generation forecast.
29

30 **ANSWER:**

31
32 **(a)**

33
34 Not confirmed. Specifically, Yukon Energy is not requesting approval of a ST hydro
35 forecast for the 2017/18 GRA and is seeking approval of a LTA hydro generation forecast
36 [as applied for in the June 2017 GRA Filing]. As noted in YEC’s December 6, 2017 letter,
37 and in Section 2.2 and 2.5 and Appendix 2.2 of the ERA Application Part 2 Filing, Yukon

1 Energy does not consider the ST Alternative GRA Forecast to be appropriate for rate
2 setting at this time, and YEC is not applying for and does not support the ST Alternative
3 GRA Forecast.

4
5 The basis for adopting a LTA forecast instead of a ST forecast are outlined in detail in the
6 Two Part ERA Filing at pages 2-11 to 2-15. The following is summarized at page 2-14 of
7 the Two Part ERA Filing regarding why use of the LTA forecast for hydro generation is
8 being sought and is considered better than use of the ST forecast:

- 9
- 10 • Discontinuing for the 2017 period forward a DCF based on LTA water conditions
11 (and instead relying on short-term water conditions forecasts and a related ST DCF
12 or contingency fund mechanism) would:
13
 - 14 o Increase rate instability for ratepayers;
 - 15 o Mask rather than display the expected long term cost of power; and
 - 16 o Frustrate rather than facilitate intergenerational equity and fair treatment
17 related to the benefits provided by hydro generation over its long term
18 economic life.
 - 19
20 • Retaining LTA forecasts for hydro generation for the 2017 period forward, as
21 provided for in the current GRA, adopts the approach that the Board has previously
22 approved, and what YEC has applied for in the current GRA, in order to address
23 rate stability objectives and appropriate LTA price signals to ratepayers.
- 24

25 The sentence in the preamble relates in part to Figure 2-1 of the ERA Two Part Application
26 which outlines the linear nature of the key inter-relationships between LTA hydro
27 generation, the DCF and the ERA. The key point outlined in Figure 2-1 and outlined in
28 the reference quotation from the YECSIM Model GRA Presentation is that the forecast
29 approach adopted in the GRA [whether LTA or ST] must be consistently used for
30 contingency fund implementation (post GRA) and for determining final utility costs for each
31 fiscal year (in particular ERA determinations). Simply put, both steps are needed (i.e., the
32 GRA forecast and the subsequent contingency fund implementation) whether a ST or LT
33 forecast is adopted, and the same forecast methodology must be used at each step.

1 **(b) and (c)**

2
3 Not confirmed. Yukon Energy is not requesting approval of a ST hydro forecast for the
4 2017/18 GRA and is seeking approval of a LTA hydro generation forecast [as applied for
5 in the June 2017 GRA Filing]. As such, the forecast revenue shortfalls in Yukon Energy's
6 Application have not been reduced.

7
8 The referenced document provided by Yukon Energy on December 18, 2017, was
9 provided in response to the Board's direction in Order 2017-08 to provide an alternative
10 GRA forecast using a short-term hydro-electric forecast. Appendix 2.2 of the Two Part
11 ERA Application outlines the key differences and specific details of all costs that are
12 changed in the ST Alternative Forecast compared to the LTA forecast that Yukon Energy
13 is seeking approval for in its GRA.

1 **TOPIC:**

2
3 **REFERENCE:** YECSIM Model in GRA Presentation, February 12, 2018, page 9
4 *“History Leading to YECSIM in 2017/18 GRA”*
5

6 **PREAMBLE:**

7
8 **QUESTION:**
9

- 10 a) Please confirm that the mechanisms in place during the 1990s were the result of
11 a negotiated settlement.
12
13 b) Please confirm that there was abundant hydro generation available in the 1998-
14 2011 time period which resulted in the suspension of the DCF.
15
16 c) Please provide a chronological history of the DCF noting the drivers and purposes
17 for additions and withdrawals to the DCF. Please provide explanations for
18 differences in drivers and purposes.
19
20 d) Please provide a schedule showing demand as a percentage of hydro generation
21 available for the years 1997 through 2017.
22
23 e) Please confirm that natural load growth has more than made up for the load lost
24 when the Faro mine ceased operations.
25

26 **ANSWER:**

27
28 **(a)**
29

30 Not confirmed. See response to YUB-YEC-2-2(c-d) and YUB-YEC-2-3(b-d). The DCF was
31 approved following a negotiated settlement that occurred for the 1996/97 GRA. The earlier
32 Low Water Reserve Fund was approved as part of the 1991/92 GRA and the 1993/94
33 GRA and did not involve a negotiated settlement.
34

35 **(b)**
36

37 Confirmed as a general statement of load relative to LTA hydro.

1 The DCF was effectively suspended in 1998 after the closure of the Faro mine resulted in
2 a material surplus of hydro generation on the WAF system at LTA and diesel no longer
3 being considered on the margin.

4
5 However, it is noted that in 1999 pursuant to the DCF rules then in place, the DCF was
6 used to pay for the costs of baseload generation using diesel due to extremely low water
7 conditions. See response to YUB-YEC-2-3(b, c and d).

8
9 **(c)**

10
11 Attachment 1 to this response provides the continuity schedule for the years 1996-2013
12 filed as part of the 2014 DCF/ERA proceeding in response to UCG-YEC-1-6(b). Appendix
13 3.5 of the 2017-18 GRA provides DCF continuity from 2012 to 2016.

14
15 Attachment 2 to this response provides an excerpt of the response to UCG-YEC-1-2(a)
16 filed as part of the 2014 DCF/ERA proceeding. This reviews the Board Orders related to
17 the DCF [additions/ deletions etc.] between 1997 and 2011. See response to YUB-YEC-
18 2-3(d), and the related attachment, for detailed review of DCF operation, drivers and
19 changes during the period through to end of 1998 when the DCF was last active.

20
21 **(d)**

22
23 Please see Table 1 below for the requested information. It includes total YEC load
24 (including secondary sales) and hydro generation on all systems, i.e., prior to new
25 transmission connections the load includes Dawson City and Mayo hydro as well as WAF.

Table 1: Total YEC Load and Hydro Generation for 1997-2017 Years

	Total Load, GW.h	Hydro, GW.h	% Hydro of Total Load
1997	349	253	72.5%
1998	287	264	92.3%
1999	270	243	89.8%
2000	269	252	93.9%
2001	273	257	94.1%
2002	280	262	93.8%
2003	295	282	95.8%
2004	303	301	99.3%
2005	309	308	99.5%
2006	327	325	99.3%
2007	333	331	99.5%
2008	344	342	99.4%
2009	374	371	99.2%
2010	382	377	98.6%
2011	401	384	95.9%
2012	427	423	99.2%
2013	423	421	99.5%
2014	402	400	99.5%
2015	418	413	98.7%
2016	418	411	98.4%
2017	456	441	96.8%

(e)

Not confirmed, assuming “natural growth” references non-industrial firm loads.

The Faro mine’s last full year (1996) showed a mine load of 178 GW.h; with losses, this accounted for 191 GW.h of YEC generation. By 1997, the last year of Faro operation, its generation load had declined to about 83 GW.h.

Non-industrial firm load growth since 1996 for all YEC systems (i.e., not only WAF) was about 72 GW.h by 2016 and 104 GW.h by 2017. If measured since 1997 (when non-

- 1 industrial load was about 30 GW.h lower than in 1996), non-industrial firm load growth for
2 all YEC systems was about 102 GW.h by 2016 and 134 GW.h by 2017.¹
3
4 In short, “natural growth” since 1996 or 1997 has been well below the total load lost when
5 the Faro mine ceased full operations.

¹ Non-mine total YEC generation firm load in 1996 (all systems) was about 296 GW.h; in 1997, this load had declined to about 266 GW.h; in 2016, this load was about 368 GW.h; in 2017, this load was about 400 GW.h.

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

**YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE**

FOR THE YEAR			
1996	Opening balance	500,000.00	
	YUB approved deposits	3,540,046.00	4,040,046.00
	YEC withdrawals - Fuel	(942,817.87)	
	YEC withdrawals - O&M	(189,048.95)	(1,131,866.82)
	YECL withdrawals		(325,803.92)
	Interest Income/Service Fees		188,741.49
	Ending Balance		2,771,116.75
1997	Opening balance		2,771,116.75
	YUB 1997/7 Drawdown		(346,275.62)
	YEC Whitehorse Hydro Plant Fire		516,167.23
	YEC drawdown - Fuel	(11,039.59)	
	YEC drawdown - O&M	(2,213.61)	(13,253.20)
	YECL withdrawals		(177,878.50)
	Interest Income/Service Fees		85,132.72
	Ending Balance		2,835,009.38
1998	Opening balance		2,835,009.38
	DCF Rider Drawdown		(1,283,018.76)
	YEC Forest Fire - Transfer impact to RFID		58,182.00
	YEC buildup - Fuel	399,743.47	
	YEC buildup - O&M	80,154.48	479,897.95
	YECL Net withdrawals		(12,958.18)
	Interest Income/Service Fees		158,646.58
	Ending Balance		2,235,758.97
1999	Opening balance		2,235,758.97
	DCF Rider Drawdown		(1,173,011.23)
	YEC buildup - Fuel	(943,298.36)	
	YEC buildup - O&M	(189,145.28)	(1,132,443.64)
	YECL Net withdrawals		-
	YEC Whitehorse Hydro Plant Fire		674,413.21
	Interest Income/Service Fees		43,291.97
	Ending Balance		648,009.28
2000	Opening balance		648,009.28
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		34,712.64
	Ending Balance		682,721.92

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
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Yukon Energy Corporation
UCG-1-6(b) Attachment 1

**YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE**

FOR THE YEAR		
2001	Opening balance	682,721.92
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	32,510.57
	Ending Balance	<u>715,232.49</u>
2002	Opening balance	715,232.49
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	19,135.69
	Ending Balance	<u>734,368.18</u>
2003	Opening balance	734,368.18
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	21,056.11
	Ending Balance	<u>755,424.29</u>
2004	Opening balance	755,424.29
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	16,296.98
	Ending Balance	<u>771,721.27</u>
2005	Opening balance	771,721.27
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	19,184.49
	Ending Balance	<u>790,905.76</u>

Application to Revise the
Diesel Contingency Fund ("DCF")
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Yukon Energy Corporation
UCG-1-6(b) Attachment 1

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR		
2006	Opening balance	790,905.76
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	29,701.89
	Ending Balance	<u>820,607.65</u>
2007	Opening balance	820,607.65
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	35,413.19
	Ending Balance	<u>856,020.84</u>
2008	Opening balance	856,020.84
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	26,672.56
	Ending Balance	<u>882,693.40</u>
2009	Opening balance	882,693.40
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	3,967.40
	Ending Balance	<u>886,660.80</u>
2010	Opening balance	886,660.80
	DCF Rider Drawdown	-
	YEC buildup - Fuel	-
	YEC buildup - O&M	-
	YECL Net withdrawals	-
	Interest Income/Service Fees	4,443.48
	Ending Balance	<u>891,104.28</u>

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

**YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE**

FOR THE YEAR			
2011	Opening balance		891,104.28
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		10,752.27
	Ending Balance		<u>901,856.55</u>
2012	Opening balance		901,856.55
	DCF Rider Drawdown		-
	YEC buildup - Fuel	3,714,782.34	
	YEC buildup - O&M	-	3,714,782.34
	YECL Net withdrawals		-
	Interest Income/Service Fees		9,970.59
	Ending Balance		<u>4,626,609.48</u>
2013	Opening balance		4,626,609.48
	DCF Rider Drawdown		-
	YEC buildup - Fuel	3,517,981.67	
	YEC buildup - O&M		3,517,981.67
	YECL Net withdrawals		-
	Interest Income/Service Fees		52,410.15
	Ending Balance		<u>8,197,001.30</u>

Application to Revise the
Diesel Contingency Fund ("DCF")
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Yukon Energy Corporation
UCG-1-6(b) Attachment 1

1996 DCF CALCULATIONS - REVISED															
TABLE 1: YUKON ENERGY CORPORATION - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1996 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
Actual generation - KWh															
Hydro	1	Manual Input	30,465,457	32,454,966	32,760,654	29,982,564	27,039,651	23,572,986	25,817,964	28,198,591	28,573,048	27,038,103	23,736,101	29,701,916	339,342,001
Wind	1a	Manual Input	(40)	28,080	39,790	13,110	17,210	18,730	6,960	11,380	27,270	12,000	25,560	30,120	230,170
Diesel	2	Manual Input	17,177,760	7,209,330	5,989,070	5,977,420	7,005,540	7,243,322	4,933,088	3,162,720	3,625,320	10,750,230	16,753,380	14,727,960	104,555,340
Total	3	Line 1 + Line 2	47,643,177	39,692,376	38,789,514	35,975,094	34,062,401	30,835,038	30,758,012	31,372,691	32,225,838	37,800,333	40,515,041	44,459,996	444,127,511
Forecast Generation - KWh															
Hydro	4	Manual Input	29,406,071	26,221,576	26,492,008	26,018,859	24,202,463	30,159,783	31,072,278	30,772,277	31,299,877	32,502,304	33,164,963	29,775,270	351,087,729
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	13,546,393	12,303,651	12,307,032	9,070,912	9,656,998	1,921,573	920,630	1,321,175	1,857,321	3,507,206	5,491,645	11,938,380	83,859,916
Total	6	Line 4 + Line 5	42,982,464	38,570,227	38,827,040	35,114,771	33,883,461	32,096,356	32,007,908	32,113,452	33,182,198	36,039,510	38,686,608	41,743,650	435,247,645
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	1,029,346	6,233,470	6,280,436	3,951,815	2,830,398	(6,583,067)	(5,262,354)	(2,582,306)	(2,724,559)	(5,482,201)	(9,433,302)	(73,234)	(11,815,558)
Diesel	8	Line 2 - Line 5	3,631,367	(5,111,321)	(6,317,962)	(3,093,492)	(2,651,458)	5,321,749	4,012,458	1,841,545	1,768,199	7,243,024	11,261,735	2,789,580	20,695,424
Total (favourable)	9	Line 3 - Line 6	4,660,713	1,122,149	(37,526)	858,323	178,940	(1,261,318)	(1,249,896)	(740,761)	(956,360)	1,760,823	1,828,433	2,716,346	8,879,866
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	1	1	1	1	1	1	1	1	1	1	1	1	1
YEC generation requirement at long term average Hydro capability															
Forecast generation	11	Line 5	13,546,393	12,303,651	12,307,032	9,070,912	9,656,998	1,921,573	920,630	1,321,175	1,857,321	3,507,206	5,491,645	11,938,380	83,859,916
Total variance	12	Line 9	4,660,713	1,122,149	(37,526)	858,323	178,940	(1,261,318)	(1,249,896)	(740,761)	(956,360)	1,760,823	1,828,433	2,716,346	8,879,866
Line 11 + Line 12	13	Line 11 + Line 12	18,207,106	13,442,800	12,269,506	9,929,235	9,835,938	660,255	(329,266)	580,414	900,961	5,268,029	7,320,078	14,654,726	92,739,781
Expected generation	14	Line 13 if Line 10=1, other=0	18,207,106	13,442,800	12,269,506	9,929,235	9,835,938	660,255	(329,266)	580,414	900,961	5,268,029	7,320,078	14,654,726	92,739,781
Maximum savings available	14a	Line 5	13,546,393	12,303,651	12,307,032	9,070,912	9,656,998	1,921,573	920,630	1,321,175	1,857,321	3,507,206	5,491,645	11,938,380	83,859,916
Actual diesel generation	15	Line 2	17,177,760	7,209,330	5,989,070	5,977,420	7,005,540	7,243,322	4,933,088	3,162,720	3,625,320	10,750,230	16,753,380	14,727,960	104,555,340
Diesel savings (excess) (KWh)															
Line 14-Line 15 (max line 14a)	16	Line 14-Line 15 (max line 14a)	1,029,346	6,233,470	6,280,436	3,951,815	2,830,398	(6,583,067)	(5,262,354)	(2,582,306)	(2,724,559)	(5,482,201)	(9,433,302)	(73,234)	(11,815,558)
Standard efficiency(wh/h)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard times - 600 times	18	Line 16-Line 17	277,452	1,680,181	1,692,840	1,065,179	762,910	(1,774,412)	(1,418,424)	(696,039)	(734,382)	(1,477,682)	(2,542,668)	(18,740)	(3,184,786.66)
Standard price(\$ per litre)	19	Manual Input	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038
Reserve Buildup (drawdown)															
YEC Variable O&M costs(\$ per litre)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	82,136.23	497,397.32	501,144.94	315,333.49	225,850.47	(525,293.26)	(419,907.47)	(206,054.11)	(217,405.09)	(437,450.08)	(752,726.42)	(5,843.69)	(942,817.87)
YEC Variable O&M costs	22	Line 20 x Line 16	16,469.63	99,735.52	100,486.98	63,229.03	45,286.36	(105,329.07)	(84,197.66)	(41,316.90)	(43,592.84)	(87,115.22)	(150,932.83)	(1,171.75)	(189,048.95)
YEC buildup (drawdown)	23	Line 21+22	98,605.78	597,132.84	601,631.92	378,562.52	271,136.83	(630,622.33)	(504,105.13)	(247,371.01)	(260,998.03)	(525,165.30)	(903,659.45)	(7,015.44)	(1,131,866.82)
YECIL buildup (drawdown)	24	See Table 2	(27,891.82)	(29,143.30)	(18,263.55)	(25,293.64)	(14,055.96)	(17,859.11)	(35,245.08)	(40,349.39)	(13,599.28)	(33,417.17)	(33,950.46)	(25,803.92)	(325,803.92)
Total buildup (drawdown)	25	Line 23 +24	70,714.14	567,989.51	583,368.37	353,268.88	257,080.87	(646,481.44)	(543,348.21)	(287,720.40)	(274,597.31)	(556,582.47)	(937,609.91)	(41,752.77)	(1,457,670.74)
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26		0.00	4,110,760.14	4,678,749.65	5,262,118.02	5,615,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.94	2,624,128.03	
Reserve Buildup (drawdown)	27	Line 25	70,714.14	567,989.51	583,368.37	353,268.88	257,080.87	(646,481.44)	(543,348.21)	(287,720.40)	(274,597.31)	(556,582.47)	(937,609.91)	(41,752.77)	(1,457,670.74)
Transfer LWRP balance	28		500,000.00												500,000.00
YUB approved deposits	29		3,540,046.00												3,540,046.00
Ending reserve balance	30	Line 26+27+28+29	4,110,760.14	4,678,749.65	5,262,118.02	5,615,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.94	2,624,128.03	2,582,375.26	
Interest Calculation:															
Monthly interest rate	31		4.109%	4.109%	4.109%	4.109%	4.109%	4.220%	4.220%	4.220%	4.220%	4.287%	4.407%	4.407%	
Monthly interest earned	32	(Beg-End)/2 * rate * (days/365)	14,222.49	13,875.00	17,395.00	18,445.00	20,157.00	19,390.00	17,935.00	16,478.00	15,000.00	14,260.00	11,506.00	10,078.00	188,741.49
Service fees	33		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net interest earned	34	Line 32+33	14,222.49	13,875.00	17,395.00	18,445.00	20,157.00	19,390.00	17,935.00	16,478.00	15,000.00	14,260.00	11,506.00	10,078.00	188,741.49
Cumulative net interest earned	35		14,222.49	28,097.49	45,492.49	63,937.49	84,094.49	103,484.49	121,419.49	137,897.49	152,897.49	167,157.49	178,663.49	188,741.49	
Ending reserve balance including interest	36	Line 30+35	4,124,982.63	4,706,847.14	5,307,610.51	5,679,324.39	5,956,562.26	5,327,470.82	4,802,057.61	4,530,815.21	4,271,217.90	3,728,895.43	2,802,791.52	2,771,116.75	
Interest Calculation															
Interest earned			14,222.49	28,097.49	45,492.49	63,937.49	84,094.49	103,484.49	121,419.49	137,897.49	152,897.49	167,157.49	178,663.49	188,741.49	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net interest earned			14,222.49	28,097.49	45,492.49	63,937.49	84,094.49	103,484.49	121,419.49	137,897.49	152,897.49	167,157.49	178,663.49	188,741.49	
Ending reserve balance			4,110,760.14	4,678,749.65	5,262,118.02	5,615,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.94	2,624,128.03	2,582,375.26	
Ending reserve balance			4,124,982.63	4,706,847.14	5,307,610.51	5,679,324.39	5,956,562.26	5,327,470.82	4,802,057.61	4,530,815.21	4,271,217.90	3,728,895.43	2,802,791.52	2,771,116.75	
TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1996 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line #	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
Actual generation - Mwh															
Hydro	1	Manual Input	565,901	546,130	602,950	555,560	651,514	651,865	425,938	454,234	723,343	519,936	465,090	478,320	6,640,781
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	815,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(291,160)	(304,226)	(190,653)	(264,039)	(146,729)	(186,431)	(409,660)	(421,207)	(141,962)	(327,963)	(354,409)	(362,624)	(3,401,063)
Purchased power savings (loss) - Mwh															
Line 18 if diesel on margin (see Table 1, line 10)	4		(291,160)	(304,226)	(190,653)	(264,039)	(146,729)	(186,431)	(409,660)	(421,207)	(141,962)	(327,963)	(354,409)	(362,624)	(3,401,063)
Standard efficiency			3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard times	17	YEC - Line 17	(78,480)	(82,002)	(51,389)	(71,170)	(39,550)	(50,251)	(110,420)	(113,533)	(39,265)	(88,400)	(95,530)	(97,742)	(916,772)
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - \$000															
Line 18 x Line 19	20		(24,258.06)	(24,275.71)	(15,213.10)	(27,069.02)	(11,708.30)	(14,876.21)	(32,688.52)	(33,610.08)	(11,327.89)	(26,167.76)	(28,279.92)	(28,935.35)	(271,381.38)
Variable O&M costs - \$000	21	YEC Line 21 x Line 4	(6,233.06)	(4,878.74)	(6,262.62)	(3,050.45)	(4,224.62)	(2,347.66)	(2,982.80)	(6,554.56)	(6,739.31)	(2,271.39)	(5,247.43)	(6,754.51)	(80,308.98)
Reserve buildup (drawdown) - \$000	22	Line 20 x Line 21	(27,891.82)	(29,143.30)	(18,263.55)	(25,293.64)	(14,055.96)	(17,859.11)	(35,245.08)	(40,349.39)	(13,599.28)	(33,417.17)	(33,950.46)	(25,803.92)	(325,803.92)
Opening reserve															
Line 25 prior period	23		(325,803.92)	(62,960.12)	(57,360.47)	(70,524.30)	(100,917.94)	(114,973.97)	(132,833.03)	(172,076.09)	(212,425.49)	(226,024.76)	(257,441.93)	(291,392.39)	

August 19, 2014
April 6, 2018

6 of 20
Page A-6

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

1999 DCF CALCULATIONS															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1998 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	36,039,040	21,433,141	22,326,425	18,580,593	18,161,991	18,545,167	16,106,899	18,101,121	18,145,949	20,640,506	22,898,681	24,840,153	253,819,666
Wind	1a	Manual Input	14,600	31,080	26,080	31,570	32,370	13,280	17,600	22,260	21,790	23,130	10,310	14,520	258,590
Diesel	2	Manual Input	6,505,130	-	19,320	1,680	2,478	607,362	2,940	420	4,200	34,440	17,160	17,600	7,199,130
Total	3	Line 1 + Line 2	42,562,770	21,464,221	22,371,825	18,612,163	18,196,041	18,560,925	16,731,861	18,126,321	18,168,159	20,667,836	22,943,431	24,871,833	261,277,386
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,892	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	5,617,017	(6,285,493)	(4,667,665)	(5,231,335)	(6,531,857)	(14,416,485)	(14,662,457)	(12,768,449)	(13,656,876)	(11,869,040)	(7,886,235)	(4,950,465)	(97,309,340)
Diesel	8	Line 2 - Line 5	(5,330,316)	(10,561,268)	(11,938,273)	(11,564,239)	(9,500,641)	(1,200,532)	(738,692)	(1,347,572)	(1,442,255)	(3,607,565)	(7,960,791)	(11,834,048)	(77,006,192)
Total (favourable)	9	Line 3 - Line 6	286,701	(16,846,761)	(16,585,938)	(16,795,574)	(16,032,498)	(15,617,017)	(15,401,149)	(14,116,021)	(15,099,131)	(15,476,605)	(15,847,026)	(16,784,513)	(174,315,532)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	1	-	-	-	-	-	-	-	-	-	-	-	-
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	286,701	(16,846,761)	(16,585,938)	(16,795,574)	(16,032,498)	(15,617,017)	(15,401,149)	(14,116,021)	(15,099,131)	(15,476,605)	(15,847,026)	(16,784,513)	(174,315,532.00)
Expected generation	13	Line 11 + Line 12	12,126,147	(6,285,493)	(4,648,345)	(5,231,335)	(6,530,177)	(14,414,007)	(14,055,095)	(12,765,509)	(13,656,456)	(11,864,840)	(7,851,795)	(4,933,305)	(90,110,210.00)
Maximum savings available	14	Line 13 if Line 10=1, other=0	12,126,147	-	-	-	-	-	-	-	-	-	-	-	12,126,147.00
Actual diesel generation	15	Line 2	6,505,130	-	19,320	-	1,680	2,478	607,362	2,940	420	4,200	34,440	17,160	7,199,130.00
Diesel savings (excess) (KWh)															
Standard efficiency (kWh/litre)	16	Line 14-Line 15(max line 14a)	5,617,017	-	-	-	-	-	(607,362)	-	-	-	-	-	5,009,655.00
Standard litres - 000 litres	17	Manual Input	3.71	-	3.71	-	3.71	-	3.71	-	3.71	-	3.71	-	3.71
Standard price (¢ per litre)	18	Line 16/Line 17	1,514,021	-	-	-	-	-	(163,709)	-	-	-	-	-	1,350,311.32
Standard price (¢ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve buildup (drawdown)															
YEC Variable O&M costs (¢ per litre)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	448,207.68	-	-	-	-	-	(48,464.21)	-	-	-	-	-	399,743.47
YEC Variable O&M costs	22	Line 20 x Line 16	89,872.27	-	-	-	-	-	(9,717.79)	-	-	-	-	-	80,154.48
YEC buildup (drawdown)	23	Line 21+22	538,079.95	-	-	-	-	-	(58,182.00)	-	-	-	-	-	479,897.95
YECCL buildup (drawdown)	24	See Table 2	(12,958.18)	-	-	-	-	-	-	-	-	-	-	-	(12,958.18)
Total buildup (drawdown)	25	Line 23 +24	525,121.77	-	-	-	-	-	(58,182.00)	-	-	-	-	-	466,939.77
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	2,835,009.38	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,058,128.35	2,759,812.50	2,422,325.99	-
Reserve Buildup (drawdown)	27	Line 25	525,121.77	-	-	-	-	-	(58,182.00)	-	-	(302,002.80)	(298,315.85)	(337,486.51)	(345,213.60)
Rider drawdown	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,058,128.35	2,759,812.50	2,422,325.99	2,077,112.39	-
Interest Calculation															
Monthly interest rate	31	-	4.78%	4.92%	5.01%	5.11%	5.13%	5.13%	5.03%	4.49%	6.16%	5.83%	5.80%	5.56%	-
Monthly interest earned	32	(Beg+End)/2 * rate * (days/365)	12,586.00	12,694.00	14,342.00	14,184.00	14,738.00	14,307.00	14,509.00	12,987.00	16,506.00	14,710.00	12,676.00	10,966.00	165,205.00
Service fees	33	-	(1,850.89)	0.00	0.00	(1,780.51)	0.00	0.00	(1,466.09)	0.00	(1,466.97)	0.00	0.00	0.00	(6,558.42)
Net interest earned	34	Line 32+33	10,735.11	12,694.00	14,342.00	12,403.49	14,738.00	14,307.00	13,042.95	12,987.00	15,039.00	13,243.03	12,676.00	10,966.00	158,646.58
Cumulative net interest earned	35	-	10,735.11	23,429.11	37,771.11	50,174.60	64,912.60	79,219.60	92,268.55	105,255.55	121,761.55	135,004.58	147,680.58	158,646.58	-
Ending reserve balance including interest	36	Line 30+35	3,370,866.26	3,383,560.26	3,397,902.26	3,410,305.75	3,425,043.75	3,439,350.75	3,452,399.70	3,465,386.70	3,179,889.90	2,894,817.08	2,570,006.57	2,235,738.97	-
Interest Calculation															
Interest earned	-	-	12,586.00	12,694.00	14,342.00	14,184.00	14,738.00	14,307.00	14,509.00	12,987.00	16,506.00	14,710.00	12,676.00	10,966.00	165,205.00
Account fees	-	-	(1,850.89)	(1,850.89)	(1,850.89)	(0,631.40)	(3,631.40)	(3,631.40)	(5,091.49)	(5,091.49)	(6,558.42)	(6,558.42)	(6,558.42)	(6,558.42)	-
Net interest earned	-	-	10,735.11	12,694.00	14,342.00	12,403.49	14,738.00	14,307.00	13,042.95	12,987.00	15,039.00	13,243.03	12,676.00	10,966.00	158,646.58
Ending reserve balance	-	-	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,058,128.35	2,759,812.50	2,422,325.99	2,077,112.39	-
Ending reserve balance	-	-	3,370,866.26	3,383,560.26	3,397,902.26	3,410,305.75	3,425,043.75	3,439,350.75	3,452,399.70	3,465,386.70	3,179,889.90	2,894,817.08	2,570,006.57	2,235,738.97	-
TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1998 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	721,790	560,440	665,200	667,690	557,790	360,150	390,080	363,280	279,960	255,230	271,820	467,800	5,561,230
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh	3	Line 1 - Line 2	(135,271)	(289,916)	(128,403)	(151,909)	(240,453)	(478,146)	(445,518)	(512,161)	(585,345)	(592,669)	(547,679)	(373,144)	(4,480,614)
Purchased power savings (loss) - Mwh															
Hydro	4	Line 3 if diesel on margin (see Table 1, line 10)	(135,271)	-	-	-	-	-	-	-	-	-	-	-	(135,271.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	(36,461)	-	-	-	-	-	-	-	-	-	-	-	(36,461.19)
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - \$000	20	Line 18 x Line 19	(10,793.84)	-	-	-	-	-	-	-	-	-	-	-	(10,793.84)
Variable O&M costs - \$000	21	YEC Line 21 x Line 4	(2,164.34)	-	-	-	-	-	-	-	-	-	-	-	(2,164.34)
Reserve buildup (drawdown) - \$000	22	Line 20 x Line 21	(12,958.18)	-	-	-	-	-	-	-	-	-	-	-	(12,958.18)
Opening reserve															
Cumulative net interest earned - \$000	-	-	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

Schedule 5: REVISED 1999 DCF CALCULATIONS															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	24,703,222	19,755,439	21,697,737	17,173,732	16,385,634	16,648,649	16,902,905	17,048,595	17,532,436	19,765,543	21,390,108	24,120,830	233,124,830
Wind	1a	Manual Input	20,180	22,530	29,220	26,670	19,650	14,760	20,550	12,570	29,500	27,130	10,830	34,050	267,640
Diesel	2	Manual Input	3,952,140	3,088,060	139,860	1,942,780	2,063,550	13,370	3,150	99,330	183,540	73,080	488,770	266,280	12,333,910
Total	3	Line 1 + Line 2	28,675,542	22,866,029	21,866,817	19,143,182	18,468,834	16,676,779	16,926,605	17,160,495	17,745,476	19,865,753	21,889,708	24,421,160	245,726,380
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,992	30,771,956	30,871,839	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(5,713,221)	(7,971,745)	(5,293,213)	(6,643,096)	(8,320,934)	(14,311,523)	(13,863,501)	(13,830,665)	(14,262,679)	(12,740,003)	(9,394,288)	(5,650,258)	(117,995,126)
Diesel	8	Line 2 - Line 5	(7,887,306)	(7,473,208)	(11,797,793)	(6,621,469)	(7,418,771)	(1,189,640)	(1,342,904)	(1,251,182)	(1,259,135)	(3,538,685)	(7,506,461)	(11,584,928)	(71,871,412)
Total (favourable)	9	Line 3 - Line 6	(13,600,527)	(15,444,953)	(17,090,946)	(16,264,555)	(15,739,705)	(15,501,163)	(15,206,405)	(15,081,847)	(15,521,814)	(16,278,688)	(16,900,749)	(17,235,186)	(189,866,538)
Expected diesel generation - KWh															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total variance	12	Line 9	(13,600,527)	(15,444,953)	(17,090,946)	(16,264,555)	(15,739,705)	(15,501,163)	(15,206,405)	(15,081,847)	(15,521,814)	(16,278,688)	(16,900,749)	(17,235,186)	(189,866,538)
Expected generation	13	Line 11 + Line 12	(1,761,081)	(4,883,685)	(5,153,353)	(4,700,316)	(6,237,384)	(14,298,153)	(13,860,351)	(13,731,335)	(14,079,139)	(12,666,923)	(8,905,518)	(5,383,978)	(105,661,216)
Actual generation	14	Line 13 if Line 10=1, other=0	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Actual diesel generation	15	Line 2	3,952,140	3,088,060	139,860	1,942,780	2,063,550	13,370	3,150	99,330	183,540	73,080	488,770	266,280	12,333,910
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	(3,952,140)	(3,088,060)	-	(1,942,780)	(2,063,550)	-	-	-	-	-	(488,770)	(266,280)	(11,821,580)
Standard efficiency (bwt#)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard tires - 000 tires	18	Line 16a, line 17	(1,065,267)	(832,361)	-	(523,660)	(561,604)	-	-	-	-	-	(131,744)	(71,774)	(3,186,409)
Standard price(\$ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs(\$ per kWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	(315,359.47)	(246,410.54)	-	(155,023.37)	(166,256.06)	-	-	-	-	-	(39,001.21)	(21,247.71)	(943,298.36)
YEC Variable O&M costs	22	Line 20 x Line 16	(63,234.24)	(49,408.96)	-	(31,084.48)	(33,336.80)	-	-	-	-	-	(7,820.32)	(4,260.48)	(189,145.28)
YEC buildup (drawdown)	23	Line 21+22	(378,593.71)	(295,819.50)	-	(186,107.85)	(199,592.86)	-	-	-	-	-	(46,821.53)	(25,508.19)	(1,132,443.64)
YECUL buildup (drawdown)	24	See Table 2													
Total buildup (drawdown)	25	Line 23 +24	(378,593.71)	(295,819.50)	-	(186,107.85)	(199,592.86)	-	-	-	-	-	(46,821.53)	(25,508.19)	(1,132,443.64)
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	2,225,798.97	1,803,928.15	1,416,812.57	1,063,222.38	877,388.24	677,511.83	677,408.68	677,400.16	677,397.99	677,307.47	677,307.47	630,338.71	630,338.71
Reserve Buildup (drawdown)	27	Line 25	(378,593.71)	(295,819.50)	-	(186,107.85)	(199,592.86)	-	-	-	-	-	-	(46,821.53)	(25,508.19)
Rider drawdown	28		(431,830.82)	(387,115.58)	(353,590.19)	273.71	(283.55)	(103.15)	(8.52)	(2.17)	(90.52)	-	(147.23)	(113.21)	(1,173,011.23)
YEC Fire Impact	29		378,593.71	295,819.50	-	-	-	-	-	-	-	-	-	-	674,413.21
Ending reserve balance	30	Line 26+27+28+29	1,803,928.15	1,416,812.57	1,063,222.38	877,388.24	677,511.83	677,408.68	677,400.16	677,397.99	677,307.47	677,307.47	630,338.71	604,717.31	604,717.31
Interest Calculation:															
Monthly interest rate	31		5.49%	5.30%	5.31%	5.22%	4.97%	4.93%	4.98%	4.90%	4.97%	5.05%	5.08%	5.22%	
Monthly interest earned	32	(Beg+End)/2 * rate * (days/365)	9,781.00	6,581.00	5,109.00	3,963.00	3,052.00	2,659.00	2,699.00	2,660.00	2,711.00	2,761.00	2,694.00	2,638.00	47,308.00
Service fees	33		(1,389.12)	0.00	0.00	(1,062.86)	0.00	0.00	(905.02)	0.00	0.00	(659.03)	0.00	0.00	(4,016.03)
Net interest earned	34	Line 32+33	8,391.88	6,581.00	5,109.00	2,900.14	3,052.00	2,659.00	1,793.98	2,660.00	2,711.00	2,101.97	2,694.00	2,638.00	43,291.97
Cumulative net interest earned	35		8,391.88	14,972.88	20,081.88	22,982.02	26,034.02	28,693.02	30,487.00	33,147.00	35,858.00	37,959.97	40,653.97	43,291.97	
Ending reserve balance including interest	36	Line 30+35	1,812,320.03	1,431,795.45	1,083,304.26	900,370.26	703,545.85	706,101.70	707,887.16	710,544.99	713,165.47	715,267.44	670,992.68	648,009.28	
Interest Calculation:															
Interest earned			9,781.00	16,362.00	21,471.00	25,434.00	28,486.00	31,145.00	33,844.00	36,504.00	39,215.00	41,976.00	44,676.00	47,308.00	
Account fees			(1,389.12)	(1,389.12)	(1,389.12)	(2,451.98)	(2,451.98)	(2,451.98)	(3,357.00)	(3,357.00)	(3,357.00)	(4,016.03)	(4,016.03)	(4,016.03)	
Net interest earned			8,391.88	14,972.88	20,081.88	22,982.02	26,034.02	28,693.02	30,487.00	33,147.00	35,858.00	37,959.97	40,653.97	43,291.97	
Ending reserve balance			1,803,928.15	1,416,812.57	1,063,222.38	877,388.24	677,511.83	677,408.68	677,400.16	677,397.99	677,307.47	677,307.47	630,338.71	604,717.31	
Ending reserve balance			1,812,320.03	1,431,795.45	1,083,304.26	900,370.26	703,545.85	706,101.70	707,887.16	710,544.99	713,165.47	715,267.44	670,992.68	648,009.28	
TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh															
Line 3 if diesel on margin (see Table 1, line 10)	4		-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard tires	18	YEC - Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - \$000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - \$000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - \$000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative reserve balance - \$000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

Schedule 6: REVISED 2000 DCF CALCULATIONS															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31															
Continuity schedule, year ending Dec. 31, 2000 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
Actual generation - KWh															
Hydro	1	Manual Input	26,029,914	20,740,492	21,350,804	19,133,603	17,353,100	18,498,005	16,760,308	17,325,286	18,029,052	20,663,163	20,131,232	26,949,285	242,964,244
Wind	1a	Manual Input	21,080	14,940	31,070	25,830	13,070	9,950	16,400	19,690	21,160	31,890	307,725	80,739	393,544
Diesel	2	Manual Input	109,390	0	1,580	5,800	38,850	320	6,300	3,150	5,600	3,360	545,240	7,990	728,170
Total	3	Line 1 + Line 2	26,160,374	20,755,432	21,383,454	19,165,233	17,405,020	18,508,275	16,783,608	17,348,126	18,055,812	20,698,413	20,784,197	27,038,014	244,085,958
Forecast Generation - KWh															
Hydro	4a	Manual Input	30,406,623	27,721,714	26,962,170	23,816,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(4,385,629)	(6,994,282)	(5,638,296)	(4,684,065)	(7,360,048)	(12,466,977)	(14,010,248)	(13,546,854)	(13,774,403)	(11,837,623)	(10,556,269)	(2,775,114)	(108,029,808)
Diesel	8	Line 2 - Line 5	(11,730,066)	(10,561,268)	(11,936,013)	(11,558,439)	(9,463,471)	(1,202,690)	(1,339,154)	(1,347,362)	(1,437,079)	(3,608,405)	(7,449,991)	(11,843,218)	(83,477,152)
Total (favourable)	9	Line 3 - Line 6	(16,115,695)	(17,555,550)	(17,574,309)	(16,242,504)	(16,823,519)	(13,669,667)	(15,349,402)	(14,894,216)	(15,211,478)	(15,446,028)	(18,006,260)	(14,618,332)	(191,506,960)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total variance	12	Line 9	(16,115,695)	(17,555,550)	(17,574,309)	(16,242,504)	(16,823,519)	(13,669,667)	(15,349,402)	(14,894,216)	(15,211,478)	(15,446,028)	(18,006,260)	(14,618,332)	(191,506,960)
Expected generation	13	Line 11 + Line 12	(4,276,249)	(6,994,282)	(5,638,296)	(4,678,265)	(7,321,198)	(12,466,657)	(14,003,348)	(13,543,704)	(13,768,803)	(11,834,263)	(10,011,029)	(2,767,124)	(107,301,638)
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Actual diesel generation	15	Line 2	109,380	-	1,580	5,800	38,850	320	6,300	3,150	5,600	3,360	545,240	7,990	728,170
Diesel savings (excess) (KWh)															
Line 14-Line 15(max line 14a)	16		-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(yield/h)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price(\$ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs(\$ per kWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29		-	-	-	-	-	-	-	-	-	-	-	-	0.00
Ending reserve balance	30	Line 26+27+28+29	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28
Interest Calculation:															
Monthly interest rate	31	Investment Rate	5.28%	5.38%	5.49%	5.57%	5.75%	5.96%	6.02%	6.02%	6.00%	6.03%	6.03%	6.03%	
Monthly interest earned	32	(Beg+End)/2 * rate * (days/365)	3,003.00	2,686.00	2,752.00	2,801.00	2,905.00	3,020.00	3,068.00	3,083.00	3,085.00	3,115.00	3,128.00	3,141.00	35,787.00
Service fees	33		0.00	(640.99)	0.00	(630.00)	0.00	0.00	(1.70)	0.00	0.00	(1.67)	0.00	0.00	(1,074.56)
Net interest earned	34	Line 32+33	3,003.00	2,145.01	2,752.00	2,271.00	2,905.00	3,020.00	3,066.30	3,083.00	3,085.00	3,113.33	3,128.00	3,141.00	34,712.64
Cumulative net interest earned	35		3,003.00	5,148.01	7,900.01	10,171.01	13,076.01	16,096.01	19,162.31	22,245.31	25,330.31	28,443.64	31,571.64	34,712.64	
Ending reserve balance including interest	36	Line 30+35	651,012.28	653,157.29	655,909.29	658,180.29	661,085.29	664,105.29	667,171.59	670,254.59	673,339.59	676,452.92	679,580.92	682,721.92	
TD Prime Rate for Borrowing			6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation:															
Interest earned			3,003.00	5,689.00	8,441.00	11,242.00	14,147.00	17,167.00	20,235.00	23,318.00	26,403.00	29,518.00	32,646.00	35,787.00	
Account fees			0.00	(640.99)	(640.99)	(1,070.99)	(1,070.99)	(1,070.99)	(1,070.99)	(1,070.99)	(1,070.99)	(1,070.99)	(1,070.99)	(1,070.99)	
Net interest earned			3,003.00	5,148.01	7,900.01	10,171.01	13,076.01	16,096.01	19,162.31	22,245.31	25,330.31	28,443.64	31,571.64	34,712.64	
Ending reserve balance			648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	
Ending reserve balance			651,012.28	653,157.29	655,909.29	658,180.29	661,085.29	664,105.29	667,171.59	670,254.59	673,339.59	676,452.92	679,580.92	682,721.92	
TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line #	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
Actual generation - Mwh															
Hydro	1	Manual Input	-	-	-	-	-	-	-	-	-	-	-	0	
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh															
Line 3 if diesel on margin (see Table 1, line 10)	4		-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - \$000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - \$000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - \$000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative reserve balance - \$000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2001 DCF Calculations															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2001															
Continuity schedule, year ending Dec. 31, 2001 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	23,662,418	22,112,517	22,732,857	19,759,754	18,950,295	17,196,549	16,870,180	17,074,052	17,767,661	21,116,042	23,317,346	28,005,227	248,554,898
Wind	1a	Manual Input	192,757	43,981	166,748	104,171	134,867	68,644	60,814	74,786	156,429	54,297	43,477	11,940	1,112,511
Diesel	2	Manual Input	2,520	15,150	2,730	0	24,390	1,680	7,660	7,980	9,360	70,660	38,140	50,880	230,550
Total	3	Line 1 + Line 2	23,847,695	22,171,248	22,902,335	19,863,925	19,109,552	17,266,873	16,938,654	17,156,818	17,933,450	21,240,399	23,398,963	28,068,047	249,897,959
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,832	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(6,591,448)	(5,593,610)	(4,120,565)	(3,979,573)	(5,641,056)	(13,709,739)	(13,855,962)	(13,742,992)	(13,900,525)	(11,362,337)	(7,434,403)	(1,787,971)	(101,720,187)
Diesel	8	Line 2 - Line 5	(11,839,920)	(10,546,118)	(11,934,863)	(11,564,239)	(9,477,931)	(1,201,330)	(1,338,394)	(1,342,532)	(1,433,315)	(3,641,705)	(7,957,091)	(11,800,328)	(63,974,772)
Total (favourable)	9	Line 3 - Line 6	(18,428,374)	(16,139,734)	(16,055,428)	(15,543,812)	(15,118,987)	(14,911,069)	(15,194,356)	(15,085,524)	(15,333,840)	(14,904,042)	(15,391,494)	(13,588,299)	(165,694,959)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total variance	12	Line 9	(18,428,374)	(16,139,734)	(16,055,428)	(15,543,812)	(15,118,987)	(14,911,069)	(15,194,356)	(15,085,524)	(15,333,840)	(14,904,042)	(15,391,494)	(13,588,299)	(165,694,958)
Expected generation	13	Line 11 + Line 12	(6,588,928)	(5,578,466)	(4,117,835)	(3,979,573)	(5,616,666)	(13,708,059)	(13,848,302)	(13,735,012)	(13,891,165)	(11,292,277)	(7,396,263)	(1,737,091)	(101,489,638)
Maximum savings available	14	Line 13 if Line 10=1; other=0	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Actual diesel generation	15	Line 2	2,520	15,150	2,730	-	24,390	1,680	7,660	7,980	9,360	70,660	38,140	50,880	230,550
Diesel savings (excess) (KWh)															
Standard efficiency (w/w)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard litres - 000 litres	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard price(\$ per litre)	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price(\$ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs(\$ per kWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92
Interest Calculation:															
Monthly interest rate	31	Investment Rate	5.91%	5.73%	5.54%	5.26%	4.95%	4.75%	4.57%	4.48%	4.26%	4.91%	2.85%	2.64%	
Monthly interest earned	32	(Beg+End)/2 * rate * (days/365)	3,515.00	3,019.00	3,241.00	2,993.00	2,923.00	2,726.00	2,721.00	2,681.00	2,475.00	2,954.00	1,665.00	1,603.00	32,516.00
Service fees	33	-	(1.77)	0.00	0.00	(1.82)	0.00	0.00	(1.85)	0.00	0.00	0.00	0.00	0.00	(5.44)
Net interest earned	34	Line 32+33	3,513.23	3,019.00	3,241.00	2,991.18	2,923.00	2,726.00	2,719.15	2,681.00	2,475.00	2,954.00	1,665.00	1,603.00	32,510.56
Cumulative net interest earned	35	-	3,513.23	6,532.23	9,773.23	12,764.41	15,687.41	18,413.41	21,132.56	23,813.56	26,288.56	29,242.56	30,907.56	32,510.56	
Ending reserve balance including interest	36	Line 30+35	686,235.15	689,254.15	692,495.15	695,486.33	698,409.33	701,135.33	703,854.48	706,535.48	709,010.48	711,964.48	713,629.48	715,232.48	
TD Prime Rate for Borrowing			6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation:															
Interest earned			3,515.00	6,534.00	9,775.00	12,768.00	15,691.00	18,417.00	21,138.00	23,819.00	26,294.00	29,248.00	30,913.00	32,516.00	
Account fees			(1.77)	(1.77)	(1.77)	(1.82)	(1.85)	(1.85)	(1.85)	(1.85)	(1.85)	(1.85)	(1.85)	(1.85)	
Net interest earned			3,513.23	6,532.23	9,773.23	12,764.41	15,687.41	18,413.41	21,132.56	23,813.56	26,288.56	29,242.56	30,907.56	32,510.56	
Ending reserve balance			682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	
Ending reserve balance			686,235.15	689,254.15	692,495.15	695,486.33	698,409.33	701,135.33	703,854.48	706,535.48	709,010.48	711,964.48	713,629.48	715,232.48	
TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh															
Line 3 if diesel on margin (see Table 1, line 10)	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - \$000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - \$000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - \$000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative reserve balance - \$000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2002 DCF Calculations															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2002															
Continuity schedule, year ending Dec. 31, 2002 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	26,227,887	22,698,415	24,005,137	21,001,751	19,272,298	17,679,499	16,660,103	18,834,243	19,067,528	21,750,274	21,395,011	26,736,615	255,328,761
Wind	1a	Manual Input	10,210	9,250	102,500	111,940	95,140	114,930	77,838	134,572	92,790	162,290	112,127	63,520	1,087,107
Diesel	2	Manual Input	7,300	1,050	14,880	16,410	3,360	1,290	21,420	9,870	2,100	11,480	103,900	517,960	710,990
Total	3	Line 1 + Line 2	26,245,397	22,708,715	24,127,517	21,130,101	19,370,798	17,795,689	16,759,361	18,978,685	19,162,418	21,924,044	21,611,038	27,318,095	257,126,858
Forecast Generation - KWh															
Hydro	4a	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596
Wind	4	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(4,198,526)	(5,042,049)	(2,912,533)	(2,729,807)	(5,358,780)	(13,180,503)	(14,049,015)	(11,923,015)	(12,664,297)	(10,620,112)	(9,288,088)	(3,005,003)	(94,971,728)
Diesel	8	Line 2 - Line 5	(11,832,146)	(10,560,218)	(11,922,713)	(11,547,829)	(9,498,961)	(1,201,750)	(1,324,634)	(1,340,642)	(1,440,575)	(3,600,285)	(7,891,331)	(11,333,248)	(83,494,332)
Total (favourable)	9	Line 3 - Line 6	(16,030,672)	(15,602,267)	(14,835,246)	(14,277,636)	(14,857,741)	(14,382,253)	(15,373,649)	(13,263,657)	(14,104,872)	(14,220,397)	(17,179,419)	(14,338,251)	(178,466,060)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total variance	12	Line 9	(16,030,672)	(15,602,267)	(14,835,246)	(14,277,636)	(14,857,741)	(14,382,253)	(15,373,649)	(13,263,657)	(14,104,872)	(14,220,397)	(17,179,419)	(14,338,251)	(178,466,060)
Expected generation	13	Line 11 + Line 12	(4,191,226)	(5,040,999)	(2,897,653)	(2,713,397)	(5,355,420)	(13,179,243)	(14,027,595)	(11,913,145)	(12,662,197)	(10,608,632)	(9,184,188)	(2,487,043)	(94,260,738)
Maximum savings available	14	Line 13 if Line 10=1; other=0	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Actual diesel generation	15	Line 2	7,300	1,050	14,880	16,410	3,360	1,290	21,420	9,870	2,100	11,480	103,900	517,960	710,990
Diesel savings (excess) (KWh)															
Standard efficiency (w/w)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard litres - 000 litres	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard price(\$ per litre)	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price(\$ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs(\$ per kWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48
Interest Calculation:															
Monthly interest rate	31	Investment Rate	2.39%	2.21%	2.27%	2.30%	2.50%	2.70%	3.18%	2.92%	2.99%	2.97%	2.99%	2.96%	
Monthly interest earned	32	(Beg+End)/2 * rate * (days/365)	1,485.00	1,217.00	1,362.00	1,361.00	1,530.00	1,604.00	1,957.00	1,799.00	1,786.00	1,837.00	1,796.00	1,844.00	19,598.00
Service fees	33	(1.91)	(1.91)	(1.91)	(1.91)	(1.91)	(1.91)	(1.91)	(34.77)	(38.61)	(38.61)	(462.30)	(462.30)	(462.30)	(462.30)
Net interest earned	34	Line 32+33	1,483.09	1,215.09	1,360.09	1,359.09	1,530.00	1,604.00	1,922.23	1,799.00	1,786.00	1,413.30	1,333.70	1,381.70	19,135.69
Cumulative net interest earned	35	-	1,483.09	2,700.09	4,062.09	5,441.16	6,971.16	8,575.16	10,497.39	12,296.39	14,082.39	15,495.69	17,291.69	19,135.69	
Ending reserve balance including interest	36	Line 30+35	716,715.57	717,932.57	719,314.57	720,673.64	722,203.64	723,807.64	725,729.87	727,528.87	729,314.87	730,728.17	732,524.17	734,368.17	
TD Prime Rate for Borrowing			6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation:															
Interest earned			1,485.00	2,702.00	4,084.00	5,445.00	6,975.00	8,579.00	10,536.00	12,335.00	14,121.00	15,958.00	17,754.00	19,598.00	
Account fees			(1.91)	(1.91)	(1.91)	(1.91)	(1.91)	(1.91)	(38.61)	(38.61)	(462.31)	(462.31)	(462.31)	(462.31)	
Net interest earned			1,483.09	2,700.09	4,082.09	5,441.16	6,971.16	8,575.16	10,497.39	12,296.39	14,082.39	15,495.69	17,291.69	19,135.69	
Ending reserve balance			715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	
Ending reserve balance			716,715.57	717,932.57	719,314.57	720,673.64	722,203.64	723,807.64	725,729.87	727,528.87	729,314.87	730,728.17	732,524.17	734,368.17	
TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh															
Hydro	4	Line 3 if diesel on margin (see Table 1, line 10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - \$000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - \$000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - \$000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative reserve balance - \$000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-

August 19, 2014
April 6, 2018

12 of 20
Page A-12

August 19, 2014
April 6, 2018

13 of 20
Page A-13

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2005 DCF Calculations															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2005															
Continuity schedule, year ending Dec. 31, 2005 - Diesel Contingency Fund Calculations - WAF System (8000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	30,399,843	24,913,292	24,977,934	21,371,476	19,949,512	19,825,242	21,464,488	20,256,220	20,797,996	23,946,179	26,613,225	28,124,327	282,639,734
Wind	1a	Manual Input	-	138,361	113,439	59,534	74,087	58,492	45,373	100,587	121,513	104,890	-	73,552	899,828
Diesel	2	Manual Input	46,660	20,310	4,230	840	1,680	-	-	14,750	1,920	7,920	9,980	114,670	-
Total	3	Line 1 + Line 2	30,446,503	25,071,963	25,095,603	21,431,850	20,025,279	19,883,734	21,509,861	20,371,557	20,921,429	24,058,989	26,621,805	28,205,859	283,644,232
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	41,656,346	43,592,918	-
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(36,780)	(2,698,061)	(1,928,797)	(2,412,488)	(4,702,619)	(11,091,198)	(9,277,095)	(10,535,023)	(10,905,106)	(8,481,607)	(4,182,001)	(1,607,259)	(67,858,034)
Diesel	8	Line 2 - Line 5	(11,782,786)	(10,540,958)	(11,933,363)	(11,563,399)	(9,500,641)	(1,203,010)	(1,346,054)	(1,335,762)	(1,440,755)	(3,603,845)	(7,986,851)	(11,843,228)	(84,090,652)
Total (favourable)	9	Line 3 - Line 6	(11,829,566)	(13,239,019)	(13,862,160)	(13,975,887)	(14,203,260)	(12,294,208)	(10,623,149)	(11,870,785)	(12,345,861)	(12,085,452)	(12,168,852)	(13,450,487)	(151,948,686)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total variance	12	Line 9	(11,829,566)	(13,239,019)	(13,862,160)	(13,975,887)	(14,203,260)	(12,294,208)	(10,623,149)	(11,870,785)	(12,345,861)	(12,085,452)	(12,168,852)	(13,450,487)	(151,948,686)
Line 11 + Line 12	13		9,880	(2,677,751)	(1,924,567)	(2,411,648)	(4,700,939)	(11,091,198)	(9,277,095)	(10,520,273)	(10,903,186)	(8,473,887)	(4,173,621)	(1,599,279)	(67,743,364)
Expected generation															
Line 13 if Line 10=1, other=0	13														
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Actual diesel generation	15	Line 2	46,660	20,310	4,230	840	1,680	-	-	14,750	1,920	7,920	9,980	114,670	-
Diesel savings (excess) (KWh)															
Line 14-Line 15(max line 14a)	16		-	-	-	-	-	-	-	-	-	-	-	-	-
Manual Input	17		3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Line 16-Line 17	18		-	-	-	-	-	-	-	-	-	-	-	-	-
Manual Input	19		0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M cost(\$ per KWh)	20	Manual Input	0.016	-	0.016	-	0.016	-	0.016	-	0.016	-	0.016	-	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Ending reserve balance	30	Line 26+27+28+29	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monthly interest earned	32	(Beg+End)/2 * rate * (days/365)	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	19,184.49
Service fees	33	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Net interest earned	34	Line 32+33	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	19,184.49
Cumulative net interest earned	35	-	1,598.71	3,197.42	4,796.12	6,394.83	7,993.54	9,592.25	11,190.95	12,789.66	14,388.37	15,987.08	17,585.78	19,184.49	-
Ending reserve balance including interest	36	Line 30+35	773,319.98	774,918.69	776,517.39	778,116.10	779,714.81	781,313.52	782,912.22	784,510.93	786,109.64	787,708.35	789,307.05	790,905.76	-
TD Prime Rate for Borrowing															
Interest Calculation															
Interest earned			1,598.71	3,197.42	4,796.12	6,394.83	7,993.54	9,592.25	11,190.95	12,789.66	14,388.37	15,987.08	17,585.78	19,184.49	-
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned			1,598.71	3,197.42	4,796.12	6,394.83	7,993.54	9,592.25	11,190.95	12,789.66	14,388.37	15,987.08	17,585.78	19,184.49	-
Ending reserve balance			771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	-
Ending reserve balance			773,319.98	774,918.69	776,517.39	778,116.10	779,714.81	781,313.52	782,912.22	784,510.93	786,109.64	787,708.35	789,307.05	790,905.76	-

August 19, 2014
April 6, 2018

15 of 20
Page A-15

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2007 DCF Calculations															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2007															
Continuity schedule, year ending Dec. 31, 2007 - Diesel Contingency Fund Calculations - WAF System (8000)															
	Line#		Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	31,118,560	29,508,210	29,440,856	24,946,910	22,167,550	19,697,579	21,029,184	19,912,911	22,184,575	22,982,038	28,621,981	32,920,848	304,531,202
Wind	1a	Manual Input	0	0	0	111,240	86,430	41,640	42,280	0	62,970	0	0	17,120	361,680
Diesel	2	Manual Input	78,155	82,275	7,245	11,545	54,570	2,520	80	61,007	101,930	20,626	33,038	16,273	469,264
Total	3	Line 1 + Line 2	31,196,715	29,590,485	29,448,101	25,069,695	22,308,550	19,741,739	21,071,544	19,973,918	22,349,475	23,002,664	28,655,019	32,954,241	305,362,146
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,967,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,467	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	681,937	1,758,496	2,420,686	1,214,652	(2,472,238)	(11,235,713)	(9,715,492)	(10,978,919)	(9,577,070)	(9,550,638)	(2,173,245)	3,132,830	(46,494,714)
Diesel	8	Line 2 - Line 5	(11,761,291)	(10,478,993)	(11,930,348)	(11,552,694)	(9,447,751)	(1,200,490)	(1,345,974)	(1,289,505)	(1,340,745)	(3,591,139)	(7,962,193)	(11,834,935)	(83,736,056)
Total (favourable)	9	Line 3 - Line 6	(11,079,354)	(8,720,497)	(9,509,662)	(10,338,042)	(11,919,989)	(12,436,203)	(11,061,466)	(12,268,424)	(10,917,815)	(13,141,777)	(10,135,438)	(8,702,105)	(130,230,772)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(11,079,354)	(8,720,497)	(9,509,662)	(10,338,042)	(11,919,989)	(12,436,203)	(11,061,466)	(12,268,424)	(10,917,815)	(13,141,777)	(10,135,438)	(8,702,105)	(130,230,772.00)
Expected generation	13	Line 11 + Line 12	760,092	1,840,771	2,427,931	1,226,197	(2,417,668)	(11,233,193)	(9,715,412)	(10,917,912)	(9,475,140)	(9,530,012)	(2,140,207)	3,149,103	(46,025,450.00)
Line 13 if Line 10=1, other 0	14		-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	78,155	82,275	7,245	11,545	54,570	2,520	80	61,007	101,930	20,626	33,038	16,273	469,264.00
Diesel savings (excess) (KWh)															
Line 14-Line 15 (max line 14a)	16		-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(yeah)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - QOQ lines	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price(\$ per litre)	19	Manual Input	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641
Reserve Buildup (drawdown)															
YEC Variable O&M cost(\$ per kWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21-22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29		-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monthly interest earned	32	Re-invested interest	3,191.81	2,716.53	2,924.93	3,034.47	3,045.69	2,878.56	3,248.64	3,257.69	3,115.46	3,803.26	3,407.90	3,405.72	38,030.66
Service fees	33	Investment Fees	0.00	(639.24)	0.00	(645.63)	0.00	0.00	(659.26)	0.00	0.00	(673.34)	0.00	0.00	(2,617.47)
Net interest earned	34	Line 32+33	3,191.81	2,077.29	2,924.93	2,388.84	3,045.69	2,878.56	2,589.38	3,257.69	3,115.46	3,129.92	3,407.90	3,405.72	35,413.19
Cumulative net interest earned	35		3,191.81	5,269.10	8,194.03	10,582.87	13,628.56	16,507.12	19,096.50	22,354.19	25,469.65	28,599.57	32,007.47	35,413.19	
Ending reserve balance including interest	36	Line 30+35	823,799.46	825,876.75	828,801.68	831,190.52	834,236.21	837,114.77	839,704.15	842,961.84	846,077.30	849,207.22	852,615.12	856,030.84	859,444.00
		TD Prime Rate for Borrowing	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%
Interest Calculation:															
Interest earned			3,191.81	5,268.34	8,833.27	11,867.74	14,913.43	17,791.99	21,040.63	24,298.32	27,413.78	31,217.04	34,624.94	38,030.66	
Account fees			0.00	(639.24)	(639.24)	(1,284.87)	(1,284.87)	(1,284.87)	(1,944.13)	(1,944.13)	(1,944.13)	(2,617.47)	(2,617.47)	(2,617.47)	
Net interest earned			3,191.81	5,269.10	8,194.03	10,582.87	13,628.56	16,507.12	19,096.50	22,354.19	25,469.65	28,599.57	32,007.47	35,413.19	
Ending reserve balance			820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	
Ending reserve balance			823,799.46	825,876.75	828,801.68	831,190.52	834,236.21	837,114.77	839,704.15	842,961.84	846,077.30	849,207.22	852,615.12	856,030.84	

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2008 DCF Calculations														
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2008														
Continuity schedule, year ending Dec. 31, 2008 - Diesel Contingency Fund Calculations - WAF System (\$000)														
	Line#	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL
Actual generation - KWh														
Hydro	1	Manual Input	33,165,928	29,610,041	26,877,857	23,666,146	21,345,165	21,790,016	21,745,269	22,940,550	22,307,493	25,080,823	29,832,970	35,466,058
Wind	1a	Manual Input	0	0	25,100	0	174,790	39,760	70,500	18,900	0	0	101,390	436,890
Diesel	2	Manual Input	37,323	76,111	0	0	186,358	9	0	840	0	218,668	31,256	663,618
Total	3	Line 1 + Line 2	33,203,251	29,686,152	26,902,957	23,666,146	21,706,313	21,829,776	21,815,769	22,960,290	22,307,493	25,299,491	29,965,616	36,016,136
Forecast Generation - KWh														
Hydro	4	Manual Input	30,406,623	27,722,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	351,087,596
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	435,952,918
Variance - KWh														
Hydro and wind	7	Line 1 - Line 4	2,729,305	1,860,327	(117,213)	(177,352)	(3,206,263)	(9,145,156)	(8,971,187)	(7,932,380)	(9,517,122)	(7,451,853)	(860,866)	5,547,380
Diesel	8	Line 2 - Line 5	(11,802,123)	(10,495,157)	(11,937,593)	(11,564,239)	(9,315,963)	(1,203,010)	(1,346,054)	(1,349,672)	(1,442,675)	(3,393,097)	(7,963,975)	(11,187,590)
Total (favourable)	9	Line 3 - Line 6	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)
Expected diesel generation - KWh:														
Greater of (savings to a maximum of forecast diesel):														
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-
(YEC generation requirement at long term average Hydro capability)														
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208
Total variance	12	Line 9	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)
Expected generation	13	Line 11 + Line 12	2,766,628	1,936,438	(117,213)	(177,352)	(3,019,905)	(9,145,156)	(8,971,187)	(7,931,540)	(9,517,122)	(7,233,185)	(629,610)	6,210,998
Line 13 if Line 10=1, other=0	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208
Maximum savings available	15	Line 2	37,323	76,111	-	-	186,358	-	-	840	-	218,668	31,256	663,618
Diesel savings (excess) (KWh)														
Line 14-Line 15(max line 14a)	16	-	-	-	-	-	-	-	-	-	-	-	-	0.00
Standard efficiency(yeah)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - QSO lines	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-
Standard price(\$ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)														
YEC Variable O&M cost(\$ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)														
Beginning reserve	26	Line 36 prior period	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28	-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29	-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84
Interest Calculation:														
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monthly interest earned	32	Re-invested interest	3,297.73	2,870.19	2,843.68	2,521.04	2,428.57	2,383.06	2,347.38	2,172.81	2,378.75	2,339.90	1,925.31	1,881.01
Service fees	33	Investment Fees	(674.43)	0.00	0.00	(672.62)	0.00	0.00	(678.64)	0.00	0.00	(691.20)	0.00	0.00
Net interest earned	34	Line 32+33	2,623.32	2,870.19	2,843.68	1,848.42	2,428.57	2,383.06	1,668.74	2,172.81	2,378.75	1,648.70	1,925.31	1,881.01
Cumulative net interest earned	35	-	2,623.32	5,493.51	8,337.19	10,185.61	12,614.18	14,997.24	16,665.98	18,838.79	21,217.54	22,866.24	24,791.55	26,672.56
Ending reserve balance including interest	36	Line 30+35	858,644.16	861,514.35	864,358.03	866,206.45	868,635.02	871,018.08	872,686.82	874,859.63	877,238.38	879,887.08	880,812.39	882,693.40
TD Prime Rate for Borrowing	-	-	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%
Interest Calculation:														
Interest earned	-	-	3,297.73	6,167.92	9,011.60	11,532.64	13,961.21	16,344.27	18,691.65	20,864.46	23,243.21	25,583.11	27,508.42	29,389.49
Account fees	-	-	(674.43)	(674.43)	(674.43)	(1,347.03)	(1,347.03)	(1,347.03)	(2,025.67)	(2,025.67)	(2,716.87)	(2,716.87)	(2,716.87)	(2,716.87)
Net interest earned	-	-	2,623.32	5,493.51	8,337.19	10,185.61	12,614.18	14,997.24	16,665.98	18,838.79	21,217.54	22,866.24	24,791.55	26,672.56
Ending reserve balance	-	-	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84
Ending reserve balance	-	-	861,514.16	861,514.35	864,358.03	866,206.45	868,635.02	871,018.08	872,686.82	874,859.63	877,238.38	879,887.08	880,812.39	882,693.40

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2009 DCF Calculations															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2009															
Continuity schedule, year ending Dec. 31, 2009 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	TOTAL	
Actual generation - KWh															
Hydro	1	Manual Input	35,059,529	34,611,029	29,833,376	27,458,873	26,017,518	22,490,698	23,256,545	23,083,041	25,052,353	27,473,179	32,834,809	35,284,055	342,455,005
Wind	1a	Manual Input	0	0	32,860	28,520	51,680	50,250	45,763	21,200	7,950	0	0	0	238,223
Diesel	2	Manual Input	700,879	104,704	2,520	34,800	156,211	7,140	247,875	198,140	85,553	85,860	65,304	446,173	2,135,159
Total	3	Line 1 + Line 2	35,760,408	34,715,733	29,868,756	27,522,193	26,225,409	22,548,088	23,550,183	23,302,381	25,145,856	27,559,039	32,900,113	35,730,228	344,828,387
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	4,622,906	6,861,315	2,844,066	3,643,895	1,342,980	(8,433,984)	(7,484,648)	(7,787,589)	(6,764,312)	(5,059,497)	2,039,583	5,478,917	(8,694,368)
Diesel	8	Line 2 - Line 5	(11,138,567)	(10,456,564)	(11,935,078)	(11,529,439)	(9,346,110)	(1,195,870)	(1,098,179)	(1,152,372)	(1,357,122)	(3,525,905)	(7,929,927)	(11,405,035)	(82,070,163)
Total (favourable)	9	Line 3 - Line 6	(6,515,661)	(3,595,249)	(9,089,007)	(7,885,544)	(8,003,130)	(9,629,854)	(8,582,827)	(8,939,961)	(8,121,434)	(8,585,402)	(5,890,344)	(5,926,118)	(90,764,531)
Expected diesel generation - KWh															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total variance	12	Line 9	(6,515,661)	(3,595,249)	(9,089,007)	(7,885,544)	(8,003,130)	(9,629,854)	(8,582,827)	(8,939,961)	(8,121,434)	(8,585,402)	(5,890,344)	(5,926,118)	(90,764,531)
Expected generation	13	Line 11 + Line 12	5,323,785	6,966,019	2,848,586	3,678,695	1,499,191	(8,426,844)	(7,236,773)	(7,589,449)	(6,678,759)	(4,973,637)	2,104,887	5,925,090	(6,559,209)
Line 13 if Line 10=1, other=0	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Maximum savings available	15	Line 2	700,879	104,704	2,520	34,800	156,211	7,140	247,875	198,140	85,553	85,860	65,304	446,173	2,135,159
Actual diesel generation															
Line 14-Line 15(max line 14a)	16		0.00	-	-	-	-	-	-	-	-	-	-	-	0.00
Standard efficiency(yeah)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - QOO litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price(\$ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M cost(\$ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21-22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	-
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29		-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	-
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monthly interest earned	32	Re-invested interest	1,381.22	1,043.93	876.69	608.66	458.68	419.43	332.24	305.44	260.37	369.32	369.13	369.29	6,794.40
Service fees	33	Investment Fees	(696.06)	0.00	0.00	(696.26)	0.00	0.00	(695.36)	0.00	0.00	(749.32)	0.00	0.00	(2,827.00)
Net interest earned	34	Line 32+33	685.16	1,043.93	876.69	(77.60)	458.68	419.43	(363.12)	305.44	260.37	(380.00)	369.13	369.29	3,967.40
Cumulative net interest earned	35		685.16	1,729.09	2,605.78	2,528.18	2,986.86	3,406.29	3,043.17	3,348.61	3,608.98	3,228.98	3,598.11	3,967.40	-
Ending reserve balance including interest	36	Line 30+35	883,378.56	884,422.49	885,299.18	885,221.58	885,680.26	886,099.69	885,736.57	886,042.01	886,302.38	885,922.38	886,291.51	886,660.80	-
TD Prime Rate for Borrowing			6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%	-
Interest Calculation															
Interest earned			1,381.22	2,425.15	3,301.84	3,010.50	4,369.18	4,788.61	5,120.85	5,426.29	5,688.66	6,055.96	6,425.11	6,794.40	-
Account fees			(696.06)	(696.06)	(696.06)	(1,382.32)	(1,382.32)	(1,382.32)	(2,077.68)	(2,077.68)	(2,077.68)	(2,827.00)	(2,827.00)	(2,827.00)	-
Net interest earned			685.16	1,729.09	2,605.78	2,528.18	2,986.86	3,406.29	3,043.17	3,348.61	3,608.98	3,228.98	3,598.11	3,967.40	-
Ending reserve balance			882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	-
Ending reserve balance			883,378.56	884,422.49	885,299.18	885,221.58	885,680.26	886,099.69	885,736.57	886,042.01	886,302.38	885,922.38	886,291.51	886,660.80	-

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2010 DCF Calculations															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2010															
Continuity schedule, year ending Dec. 31, 2010 - Diesel Contingency Fund Calculations - WAF System (\$000)															
	Line#	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	TOTAL	
Actual generation - KWh															
Hydro	1	Manual Input	33,496,889	32,873,530	30,347,614	27,628,959	26,849,221	23,023,763	23,925,698	25,441,685	25,150,469	26,171,764	33,310,658	37,295,582	345,515,832
Wind	1a	Manual Input	0	0	0.00	0.00	3,360.00	7,480.00	14,590.00	1,040.00	37,010.00	0.00	0.00	21,140.00	84,640.00
Diesel	2	Manual Input	145,300	38,033	10,500	7,950	18,608	23,195	276,392	235,640	33,182	169,351	72,954	1,657,978	2,689,083
Total	3	Line 1 + Line 2	33,642,189	32,911,563	30,358,114	27,636,909	26,871,189	23,054,438	24,216,680	25,678,365	25,220,661	26,341,115	33,383,612	38,974,720	348,289,555
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	3,060,266	5,123,816	3,327,444	3,785,461	2,126,363	(7,943,689)	(6,846,668)	(5,449,105)	(6,637,136)	(6,360,912)	2,515,432	7,511,604	(5,787,124)
Diesel	8	Line 2 - Line 5	(11,694,146)	(10,523,235)	(11,927,093)	(11,556,289)	(9,483,713)	(1,179,815)	(1,069,662)	(1,114,872)	(1,409,493)	(3,442,414)	(7,922,277)	(10,193,230)	(81,516,239)
Total (favourable)	9	Line 3 - Line 6	(8,633,880)	(5,399,419)	(8,599,649)	(7,770,828)	(7,357,350)	(9,123,504)	(7,916,330)	(6,563,977)	(8,046,629)	(9,803,326)	(5,406,845)	(2,681,626)	(87,303,363)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(8,633,880)	(5,399,419)	(8,599,649)	(7,770,828)	(7,357,350)	(9,123,504)	(7,916,330)	(6,563,977)	(8,046,629)	(9,803,326)	(5,406,845)	(2,681,626)	(87,303,363.00)
Expected generation	13	Line 11 + Line 12	3,205,566	5,161,849	3,337,944	3,793,411	2,144,971	(7,920,494)	(6,570,276)	(5,213,465)	(6,603,954)	(6,191,561)	2,588,386	9,169,582	(3,098,041.00)
Line 13 if Line 10=1, other=0	13	Line 13 if Line 10=1, other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	145,300	38,033	10,500	7,950	18,608	23,195	276,392	235,640	33,182	169,351	72,954	1,657,978	2,689,083.00
Diesel savings (excess) (KWh)															
Line 14-Line 15(max line 14a)	16	Line 14-Line 15(max line 14a)	0.00	-	-	-	-	-	0.00	-	-	-	-	0.00	-
Manual Input	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Line 16/Line 17	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Manual Input	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M cost(\$ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monthly interest earned	32	Re-invested interest	369.44	369.60	369.75	369.90	370.06	370.21	370.37	370.52	370.68	370.83	370.98	371.14	4,443.48
Service fees	33	Investment Fees	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned	34	Line 32+33	369.44	369.60	369.75	369.90	370.06	370.21	370.37	370.52	370.68	370.83	370.98	371.14	4,443.48
Cumulative net interest earned	35	-	369.44	739.04	1,108.79	1,478.69	1,848.75	2,218.96	2,589.33	2,959.85	3,330.53	3,701.36	4,072.34	4,443.48	
Ending reserve balance including interest	36	Line 30+35	887,030.24	887,399.84	887,769.59	888,139.49	888,509.55	888,879.76	889,250.13	889,620.65	889,991.33	890,362.16	890,733.14	891,104.25	891,475.25
TD Prime Rate for Borrowing			6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%	
Interest Calculation															
Interest earned			369.44	739.04	1,108.79	1,478.69	1,848.75	2,218.96	2,589.33	2,959.85	3,330.53	3,701.36	4,072.34	4,443.48	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned			369.44	739.04	1,108.79	1,478.69	1,848.75	2,218.96	2,589.33	2,959.85	3,330.53	3,701.36	4,072.34	4,443.48	
Ending reserve balance			886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80
Ending reserve balance			887,030.24	887,399.84	887,769.59	888,139.49	888,509.55	888,879.76	889,250.13	889,620.65	889,991.33	890,362.16	890,733.14	891,104.25	891,475.25

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
UCG-1-6(b) Attachment 1

2011 DCF Calculations															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2011															
Continuity schedule, year ending Dec. 31, 2011 - Diesel Contingency Fund Calculations - WAF System (8000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	36,438,071	32,147,410	32,867,587	26,794,885	26,547,340	24,022,422	27,642,331	27,444,233	29,055,103	29,517,879	37,529,736	33,834,311	363,841,308
Wind	1a	Manual Input	0	0	0	0	0	31,979	40,248	93,752	149,610	86,500	0	0	402,089
Diesel	2	Manual Input	1,085,689	669,811	1,815,515	120,755	186,157	877,809	141,946	244,090	297,923	2,437,457	306,219	41,940	8,225,311
Total	3	Line 1 + Line 2	37,523,760	32,817,221	34,683,102	26,915,640	26,733,497	24,932,210	27,824,525	27,782,075	29,502,636	32,041,836	37,835,955	33,876,251	372,468,708
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	6,001,448	4,397,696	5,847,417	2,951,387	1,821,122	(6,920,531)	(3,104,377)	(3,353,845)	(2,619,902)	(2,928,297)	6,734,510	4,029,173	12,855,801
Diesel	8	Line 2 - Line 5	(10,753,757)	(8,891,457)	(10,122,078)	(11,443,484)	(9,316,164)	(325,201)	(1,204,108)	(1,106,422)	(1,144,752)	(1,174,308)	(7,689,012)	(11,809,268)	(75,980,011)
Total (favourable)	9	Line 3 - Line 6	(4,752,309)	(5,493,761)	(4,274,661)	(8,492,097)	(7,495,042)	(7,245,732)	(4,308,485)	(4,460,267)	(3,764,654)	(4,102,605)	(954,502)	(7,780,095)	(63,124,210)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Total variance	12	Line 9	(4,752,309)	(5,493,761)	(4,274,661)	(8,492,097)	(7,495,042)	(7,245,732)	(4,308,485)	(4,460,267)	(3,764,654)	(4,102,605)	(954,502)	(7,780,095)	(63,124,210)
Line 11 + Line 12	13		7,087,137	5,067,507	7,662,932	3,072,142	2,007,279	(6,042,722)	(2,962,431)	(3,109,755)	(2,321,997)	(490,840)	7,040,729	4,071,113	21,081,112
Expected generation	14	Line 13 if Line 10=1, other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322
Actual diesel generation	15	Line 2	1,085,689	669,811	1,815,515	120,755	186,157	877,809	141,946	244,090	297,923	2,437,457	306,219	41,940	8,225,311
Diesel savings (excess) (KWh)															
Line 14-Line 15(max line 14a)	16		0.00	0.00	0.00	-	-	0.00	-	-	0.00	0.00	0.00	-	-
Standard efficiency(ywh/)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - QSO litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price(\$ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M cost(\$ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECCL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29		-	-	-	-	-	-	-	-	-	-	-	-	-
Ending reserve balance	30	Line 26+27+28+29	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	0
Interest Calculation:															
Monthly interest rate	31	Investment Rate	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
Monthly interest earned	32	(Beg+End)/2 * rate * (days/365)	891.10	892.00	892.89	893.78	894.67	895.57	896.46	897.36	898.26	899.16	900.06	900.96	10,752.27
Service fees	33		-	-	-	-	-	-	-	-	-	-	-	-	0
Net interest earned	34	Line 32+33	891.10	892.00	892.89	893.78	894.67	895.57	896.46	897.36	898.26	899.16	900.06	900.96	10,752.27
Cumulative net interest earned	35		891.10	1,783.10	2,675.99	3,569.77	4,464.44	5,360.01	6,256.47	7,153.83	8,052.09	8,951.25	9,851.31	10,752.27	
Ending reserve balance including interest	36	Line 30+35	891,995.38	892,887.38	893,780.27	894,674.05	895,568.72	896,464.29	897,360.75	898,256.11	899,156.37	900,055.53	900,955.59	901,856.55	
TD Prime Rate for Borrowing															
Interest Calculation															
Interest earned			891.10	1,783.10	2,675.99	3,569.77	4,464.44	5,360.01	6,256.47	7,153.83	8,052.09	8,951.25	9,851.31	10,752.27	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned			891.10	1,783.10	2,675.99	3,569.77	4,464.44	5,360.01	6,256.47	7,153.83	8,052.09	8,951.25	9,851.31	10,752.27	
Ending reserve balance			891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	
Ending reserve balance			891,995.38	892,887.38	893,780.27	894,674.05	895,568.72	896,464.29	897,360.75	898,256.11	899,156.37	900,055.53	900,955.59	901,856.55	

ATTACHMENT 2: DIESEL CONTINGENCY FUND (“DCF”)

1996/97 GRA Negotiated Settlement [Orders 1996-6 and 1996-7]

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/62_boardorder1996_6.pdf

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/63_boardorder1996_7.pdf

The 1996/97 GRA consisted of a workshop negotiated settlement process and public hearing in March 1996. A negotiated settlement was reached on most, but not all issues, and included the establishment of a Diesel Contingency Fund (in place of the proposed Rate Stabilization Fund). The settlement was considered by the Board at an oral public hearing commencing March 18, 1996. The Board heard submissions regarding the Settlement from proponents of the Settlement. Parties that did not agree with certain aspects of the Settlement were allowed to present evidence and cross-examine witnesses. UCG dissented on certain aspects of the Settlement, including the ROE.

Order 1996-6 approved the revenue requirements for the companies as set out in Exhibit 148. Written reasons were provided in Order 1996-7 which included review of the Diesel Contingency Fund included in the Negotiated Settlement package. The Negotiated Settlement set out the following rules for operation of the DCF [attached to Order 1996-7]:

This fund is to replace the proposed rate stabilization fund. The fund will operate to smooth customer rate changes and offset forecast diesel costs. Rates and the fund will be determined using the long term average water expected to be available for generation (105+246 GWh). The initial funding will be determined based upon the funds available as at December 31, 1995. If additional funding becomes available due to other determinations with respect to diesel costs or other utility costs in 1995, the fund will be adjusted. The fund is only to be used for the purposes of stabilizing customer rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates.

The cap on the fund is set at the initial contribution level. If the fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider to customers over the following two years. If the fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and negative cap levels. The fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.

The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund. The annual report to the Board will also include a forecast of available water for the following year.

Order 1996-9 – UCG Complaint

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/65_boardorder1996_9.pdf

UCG filed a complaint with the Board May 2, 1995, alleging that YECL and YEC mismanaged the storage of the Aishihik Reservoir in 1993 and 1994. Specifically, UCG alleged that the Companies wasted approximately two feet of water in Aishihik Lake in 1993 and 1994 and estimated the loss to be approximately \$3 million.

The YUB retained BC Hydro International Limited to provide a preliminary opinion and assistance in determining what information is required regarding the complaint filed by UCG against YEC alleging negligence in its management of its water resources at Aishihik Lake.

The Board heard the complaint in conjunction with the hearing for the 1996/97 GRA filed by YEC and YECL. Specifically, at the March 1996 hearing, the Board heard testimony related to the Water Complaint. The Board determined that:

- YECL and YEC did not act imprudently with respect to the management of the storage of water in Aishihik Reservoir as alleged in the complaint.
- The quality of information and decision support tools used by YECL and YEC for making water management decisions was inadequate to maximize the management of stored water for the customers' benefit.

Mr. Kerslake committed YEC/YECL to the development of a plan to implement hydraulic forecasting and decision support systems and to report that plan to the Board by November of 1996. The Board accepted this commitment and ordered the plan to be filed by November 30, 1996. The Board ordered YECL and YEC to file by November 30 1996, for approval a plan to address the inadequacies identified in the Reasons for Decision attached as Appendix A to Order 1996-9.

Order 1996-11

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/57_boardorder1996_11.pdf

Order 1996-11 addressed the method for recovering from ratepayers' revenue flowing from an appeal of the YEC/ YECL 1993/94 General Rate Application.

The Board invited the Companies and intervenors to comment on the alternatives for recovery proposed by the companies; Anvil Range Mine (ARM) and the City of Whitehorse, indicated a preference for reducing the DCF by the amount of the appeal impact, while UCG submitted that the recovery should not be made by way of a reduction in the DCF but rather by a rate rider surcharge in 1997.

The Board noted Decision 1996-7 wherein it accepted a settlement package entered into by the Companies and intervenors respecting rate increases effective January 1, 1996 and January 1, 1997. Order 1996-11 notes, the terms of the settlement stipulated that with respect to the DCF “the fund is only to be used for the purposes of stabilizing rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates.”

The Board considered that the amount of \$1,952,912 should be recovered from customers by way of a rider on all billings rendered on or after January 1, 1997 until such time as the amount of \$1,952,912 is attained. The Board also notes in Order 1996-11, “this method to be fair, in the public interest and consistent with the terms of the settlement package previously accepted by the Board”.

Order 1997-4 – Appeal of Order 1996-11

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/73_boardorder1997_4.pdf

Appeal by Anvil Range Mine to Order 1996-11. The Board re-affirmed its decision, noting regarding the DCF (page 8):

Based on the submissions of the parties, the Settlement Package and the transcripts of evidence from the GRA, the Board finds as a matter of fact that the purpose of the Fund was to offset costs when the Utilities had to rely on diesel generation. It was not intended to pay for costs incurred in the past. In fact, the Diesel Contingency Fund was established before the Court of Appeal decision had been rendered. The Board is of the view that the parties to the 1996/97 GRA did not anticipate the Fund to be used to recover the Appeal revenue.

Order 1997-7

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/76_boardorder1997_7.pdf

On May 26, 1997, the YUB issued Order 1997-6 to YEC and YECL directing that (at page 1) “An interim refundable general rider surcharge of 20% be applied to the base rates for all customer classes of service effective for billings issued on or after June 1, 1997, and continuing thereafter until such time as the Faro mine resumes as a Rate Schedule 39 customer of YEC, or until the Board determines final rates for 1997.”

The Commissioner in Executive Council, pursuant to Section 17(1) of the PUA issued a direction to the Board.¹

The Commissioner in Executive council directs the Yukon Utilities Board to determine and order by July 1, 1997 a method for providing rate stabilization from the Diesel Contingency Fund established by the Board in Decision 1996-7 in the form of a minimum 25 per cent reduction for all customers in the general rider surcharge approved by the Board in Decision 1997-6. The method determined by the Board shall provide that the rate stabilization be effective on June 1, 1997 and shall continue until such time as the surcharge is removed.

The Board ordered a credit of 25% to be applied to the interim refundable general rider surcharge approved in Order 1997-6 for all customer classes of service effective for billings issued on or after June 1, 1997, and continuing thereafter until such time as the Faro mine resumes as a Rate Schedule 39 customer of YEC, or until the Board determines the final rates for 1997; and the operation of the Diesel Contingency Fund established by the Board in Order 1996-7 shall be amended to allow the recovery of the above credit from the amounts in the fund.

Order 1998-5

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/85_boardorder1998_5.pdf

The Revised Application requested an order approving the establishment of a Rate Adjustment and Stabilization Fund on a pilot basis, including a method for providing rate stabilization from the Diesel Contingency Fund (DCF). This provided for a 50% reduction for all residential and commercial customers in the proposed rider surcharge until January 31, 1999, with reduced reductions thereafter, and with provisions for replenishing the Fund.

In Appendix A to its decision, the Board notes (at page 9):

The Diesel Contingency Fund was created from the Low Water Reserve Fund, and excess customer revenues received in relation to the Faro mine. It is used to smooth rate adjustments caused by diesel generation cost instabilities due to fluctuations in hydro generation from long-term average capabilities and currently has a balance in excess of \$2.2 million (Exhibit 19, page 20).

The Board requested submissions on its jurisdiction and general consensus was that there is nothing in the Act or the OICs that limits or restricts the jurisdiction of the Board to utilize the DCF.

¹ See OIC 1997-090 on the Board's website at the following link:
http://yukonutilitiesboard.yk.ca/pdf/OICs/447_oic1997_090.pdf

The Board did not approve the establishment of a Rate Adjustment and Stabilization Fund, but directed that the balance in the DCF be used to make contributions to all eligible customers to offset 100% of the net rider increase over the next 12 months.

Order 1998-9

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/89_boardorder1998_9.pdf

By letter dated January 15, 1997, UCG made two applications to the Board (at page 1).

1. The first was an application for a review and variance of Board Order 1996-7 pursuant to s. 62 and a request for a Board investigation pursuant to s. 48 of the *Public Utilities Act*.
2. The second was a complaint regarding the Low Water Reserve Fund pursuant to ss. 44, 45 and 46 of the Act.

UCG requested an investigation as to whether the Companies saved money by using less diesel generation than forecast in 1995 and, if so, why those savings were not placed in the Low Water Reserve Fund. The Board reviewed all previous Orders with respect to the Low Water Reserve Fund and the Diesel Contingency Fund and requested additional information from the Companies and denied the request for an investigation with respect to the LWRF.

Order 1998-10 – UCG Complaint

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/80_boardorder1998_10.pdf

By letter dated June 30, 1998, the UCG filed a complaint with the Board pursuant to s. 44(1)(c) of the *Public Utilities Act* and a request for a Board investigation of the Complaint pursuant to s. 46 of the Act. UCG alleged that information in the Company's filing of the 1997 annual forecast with the Yukon Territorial Water Board (YTWB) and transcript excerpts from the 1996/97 GRA hearing provided evidence that the Companies had a secret internal policy to keep Aishihik two feet above the licensed water level, consciously misleading intervenors and the Board.

The complaint was rooted in the May 2, 1995 complaint in which UCG alleged that the decision by utility management to make early releases of water in 1993 and 1994 was imprudent and cost ratepayers \$3 million. The Board addressed the issue as part of the General Rate Application and heard extensive testimony at the March 1996 hearing. Subsequently, the Board issued Order 1996-9 which noted that the early releases were made to avoid high water levels and subsequent shoreline erosion in Aishihik Lake, to calibrate the release valves and to compensate for restrictions at the Whitehorse Rapids Plant. The Reasons for Decision (at page 2) stated that the issues to be considered were:

1. Were the forecasts of water inflow and load requirements reasonable at the time? (the Board accepted that the shortfall could not have been reasonably forecast).
2. Were the non-power producing objectives reasonable? (the Board believed that the objectives were not unreasonable).
3. Did YEC/YECL unreasonably restrict the operation of WH#4? (the Board found that the restrictions were forced outages).

The complaint was served on the utilities and their reply was received. The Board reviewed the complaint, supporting arguments and related documents and dismissed the complaint.

The Board reiterated that the Companies did not act in an imprudent manner during the water releases and no penalties are appropriate. Issues of regulatory risk and pre-approvals of utility actions were fully discussed in the 1996 UCG Submission and no new material had been presented. With respect to the complaint's reference to the value of water, this was also fully canvassed in the hearing. While the Board agreed that, in hindsight, the water had value, it took note of the uncertainties, stated that management's actions were not imprudent, and that, therefore, issues regarding the precise quantities and cost of the water were not relevant.

Order 1999-3 [Diesel Contingency Fund Reports] [Pages 1-2]

http://yukonutilitiesboard.yk.ca/pdf/Board_Order_1999-3.pdf

The terms of the 1996/97 Negotiated Settlement approved by Board Order 1996-6 provided for the creation of a Diesel Contingency Fund to smooth customer rate changes and offset forecast diesel costs. The terms also provided that an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board is to direct the companies on the additions and deletions to the fund.

On June 6, 1999 YEC filed a report, detailing the changes to the DCF in 1998, together with revised reports for 1996 and 1997. The filing also included, for convenience, copies of relevant DCF tables for YECL. On July 4, 1999 UCG responded with some preliminary concerns and requested a full review of this report with a similar process to rate hearings; interrogatories and responses to/from the Companies to the various intervenor concerns.

The Board forwarded the UCG concerns to the Companies but noted that the Board had the ultimate jurisdiction over the DCF. On October 7, 1999 YEC provided comments on the submission from UCG and additional information to assist the Board review. The Board [has] reviewed the material and finds that the approval of the report was [is] in the public interest. The Board approved [s] the additions and deletions to the DCF or 1996 to 1998 as filed.

Order 2000-1 [UCG Applications to Review and Vary Board Orders 1999-3 and 1999-5]

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/437_Board%20Order%202000-1.pdf

By letters dated December 3, 1999 and December 10, 1999 UCG made two applications to the Board to review and vary Board Orders 1999-3 and Board Orders 1999-5 respectively. The Applications for review and variance of Board Orders 1999-3 and 1999-5 were dismissed.

With regard to Order 1999-3 UCG (at page 3 of Order 2000-1) alleged that the Board made an error in jurisdiction “by not acting in the public interest by not holding a full public review and debate on the Diesel Contingency Fund”. Order 2000-1 notes as follows (at page 4):

- On June 6, 1999 Yukon Energy Corporation (“YEC”) filed a report, detailing the changes to the Diesel Contingency Fund in 1998, together with revised reports for 1996 and 1997. The filing also included for convenience copies of relevant DCF tables for the Yukon Electrical Company Limited (“YECL”). The Board found that approval of the report was in the public interest, and issued Board Order 1999-3 approving the additions and deletions to the Diesel Contingency Fund for 1996 to 1998 as filed.
- After receiving the DCF report filed by YEC, the Board distributed copies of the report to interested parties for comment. On July 4, 1999 the Utilities Consumers’ Group responded with some preliminary concerns and requested a full review of this report with a similar process similar to rate hearings; interrogatories and responses to/from Companies to various intervenor concerns. No other comments were received. The Board forwarded the UCG concerns to the Companies but noted that the Board had ultimate jurisdiction over the DCF. On October 7, 1999 Yukon Energy Corporation provided comments on the submission from the Utilities Consumers’ Group and additional information to assist the Board in its review. On October 10, 1999 UCG again argued for a “public review”, in part because the “1996/97 Settlement Agreement was very general in terms of reference for the operation.” The Board considered that it had provided for a sufficient public review and Order 1999-3 was signed on November 3, 1999 after its review of all the material received.

The Board notes in its reasons (at page 5) for decision that:

- Board Order 1999-3 simply approved the additions and deletions to the Diesel Contingency Fund for 1996 to 1998 as filed.
- The report prepared by the Yukon Energy Corporation was filed in accordance with the Board’s directions under Board Orders 1996-6, 1997-7 and 1998-5. UCG appears to be taking issue with the provisions of the latter two orders, to the extent that they amend the operation of the DCF. As well, the UCG January 31, 2000 Rebuttal points to Board Orders 1996-11 and 1997-4 as supporting its position.

The Board reviewed in detail its reasons for decision in 1996-11, 1997-4, 1997-7 and 1998-5:

- With regard to **1996-11** – The Board determined (at page 5) that “Board Order 1996-11 did not preclude the use of the DCF for stabilizing rates at another time.”
- With regard to **1997-4** - The Board determined (at page 7) that “in deciding that the DCF should not be used to recover the Appeal revenue, it did not preclude its later use to smooth rate changes.”
- With regard to **1997-7** – The Board summarized (at page 7) “that it complied with the Order-in-Council and Board Order 1997-7 amended the operation of the Diesel Contingency Fund to allow the recovery of the above credit from the amounts in the fund. No request for variance of this order was received.”
- With regard to **1998-5** – The Board concluded (at page 8) that “the purpose of the July 1998 hearing was to see what could be done to deal with the fact that the Faro mine had shut down and was not expected to return in the foreseeable future. The hearing established that there was nothing in the Act or Orders-in-Council that limited or restricted the jurisdiction of the board to utilize the DCF to help stabilize rates and mitigate the impact of what would have been a rate increase of almost 30%.”

Order 2002-3

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/100_boardorder2002_3.pdf

On April 26, 2002, YEC reported that it had reached a settlement with its insurance companies and filed a final report on the impacts relating to the fire at the Whitehorse Rapids Generating Station (“Fire Report”). YEC requested an Order that, with the filing of the Fire Report, it has complied with the reporting requirements directed by the Board and that an insurance gain of \$744,000 be placed into a deferral account for the benefit of ratepayers pending further direction of the Board. YEC also requested an Order approving that the December 31, 2000 DCF balance be changed as outlined in Section IV of the Fire Report.

On May 27, 2002 the Board provided interested parties with an opportunity to comment. After a series of information requests to YEC the Utilities Consumers’ Group and The Yukon Electrical Company Limited provided their comments, to which YEC replied on September 3, 2002.

The Board reviewed the material and noted as follows (at page 3):

- “YEC has complied with the reporting requirements directed by the Board relating to the October 1997 fire.”

- “The insurance gain of \$744,000 realized as part of the settlement of the insurance claim arising for the fire is to be placed into a deferral account as an offset to rate base for the benefit of ratepayers pending further direction of the Board.”
- “The additions and deletions to the Diesel Contingency Fund for 1999 and 2000 are approved as filed, except that the December 31, 2000 balance is to be changed from (\$61,744.29) to \$681,721.92 as outlined in section IV of the Fire Report.”

Order 2011-15 (and Appendix A)

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1306_Board%20Order%202011-15.pdf

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1307_Board%20Order%202011-15%20Appendix%20A%20Reasons%20for%20Decision.pdf

The Order and Appendix A to the Order notes [at pages 8-9]:

In further response to DCF issues, the Companies submitted that diesel was not forecast to be “on the margin”. Also, changes in operating rules are required for the DCF and those changes require Board review and approval. Furthermore, any DCF transactions are at the GRA-approved fuel price thus have no impact on the DFPVA, and that there is no interrelationship between the administration of the DFPVA and the DCF.

YEC committed to addressing DCF issues and any changes in the operating rules for the DCF in its next GRA.

As noted above, the Policy was filed in response to a direction in Board Order 2010-13.

At the time the direction was given, the Board did not contemplate issues respecting Rider D and the DCF. To strengthen the record in this proceeding, the Board issued Order 2011-12. Appendix A of that Order directed the Companies to provide adequate responses to certain information requests of LE and UCG.

Through Appendix B of Order 2011-12, the Board asked further information requests regarding the detailed calculations for the DFPVA, company risk, historical regulatory process, and the DCF. The information was needed to clarify the issues pertaining to the DCF.

The Board is satisfied with the responses of the Companies. The Board accepts the commitment of YEC to address all DCF issues in the next GRA and directs YEC to address any changes necessary in the operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA. Also, the Board requires that YEC provide a specific definition of the term “diesel on the margin”. The Board directs that YEC complete its review

and bring the necessary changes before the Board at the earliest of its next GRA or July 1, 2012.

Based on the evidence presently available to the Board, the Board accepts the submissions of the Companies that there is no interrelationship between the DFPVA and the DCF and no interrelationship between the DFPVA and Rider D.

1 **TOPIC:**

2
3 **REFERENCE:** YECSIM Model in GRA Presentation, February 12, 2018,
4 page 13 *“Fundamentals of YECSIM – Model Overview”*
5

6 **PREAMBLE:**

7
8 **QUESTION:**
9

- 10 a) Please provide an analysis for 2002 – 2017 comparing the YECSIM estimates for
11 hydro and thermal generation with actual levels of hydro and thermal generation.
12
13 b) Please identify and changes that have been made to the YECSIM model since it
14 was developed by the KGS Group in 2008.
15

16 **ANSWER:**

17
18 **(a)**
19

20 YECSIM simulation provides a long-term average based on available water year records
21 [35 years for the current GRA proposed DCF Term Sheet Table] for a given load. As
22 reviewed in response to UCG-YEC-2-8(d), YECSIM input files have not been updated to
23 include water records for 2016 and 2017.
24

25 YECSIM is used to derive the DCF Term Sheet Table, e.g., the Table 3.4 included in
26 Appendix 3.4 of the YEC 2017-18 GRA. A DCF Term Sheet Table relevant for a specific
27 GRA period is then used for the purpose of determining the volume (KWh) of LTA diesel
28 generation for any given load.
29

30 Table 1 below provides comparison of LTA hydro and thermal generation from the relevant
31 DCF Term Sheet to actuals for 2012-2017 years. The DCF Term Sheet determinations
32 noted in Table 1 are based on the DCF Term Sheet Table relevant for the particular time
33 period.

- For the years 2012-16 the DCF Term Sheet Table approved following the 2012/13 GRA [see Order 2015-01 and 2015-06] is relevant for determining thermal generation requirements.
- For the period 2017 forward the DCF Term Sheet Table included in Appendix 3.4 of the 2017/18 GRA is relevant [however, it is noted that this is subject to approval by the Board as part of the 2017/18 GRA].

**Table 1: Long-term Average Hydro and Thermal Generation based on
DCF Term Sheet Table Compared to Actuals**

GW.h	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Preliminary Actuals
YEC Grid load [excl. Fish Lake and secondary load]	424.5	419.2	396.5	410.3	412.8	439.4
DCF Term Sheet Table						
LTA hydro	409	406	391	400	402	412
LTA thermal	15.6	13.3	5.3	10.0	10.5	26.8
Wind	0.24	0.24	0.24	0.24	0.24	0.58
Actuals						
Hydro	421	417	395	405	406	426
Thermal	3.1	1.9	1.6	4.9	6.1	13.26
Wind	0.45	0.28	0.34	0.65	0.51	0.033

(b)

Major modifications to the YECSIM model since 2008 include the following:

- Interconnection of WAF and MD grids.
- Addition of Mayo B, and subsequent Mayo GS winter outflow restrictions and Mayo Lake outlet channel sediment restrictions.
- Addition of Aishihik 3rd turbine.
- Additional water years of record.
- Expanded simulation period.

1 **TOPIC:**

2
3 **REFERENCE:** YECSIM Model in GRA Presentation, February 12, 2018, page 16
4 *“Fundamentals of YECSIM – User Manual Status.”*

5 **PREAMBLE:**

6
7 **QUESTION:**

- 8
9 a) Please explain why wind generation is removed from load used for YECSIM
10 simulation.
11
12 b) Please confirm that while the YECSIM model does not separate diesel vs. LNG
13 thermal generation, YEC still separates diesel from LNG to alter the model output.
14
15 c) Please explain why the YECSIM model cannot be programmed to separate the
16 types of thermal generation.
17

18 **ANSWER:**

19
20 **(a)**

21
22 The YECSIM simulation is run based on firm load net of wind. The software is intended to
23 simulate hydro generation based on water availability. It is not intended to simulate wind
24 generation.
25

26 **(b) and (c)**

27
28 The current version of the YECSIM model has not been modified to provide a breakdown
29 of LNG and diesel. Separation of LNG and diesel within the model would require
30 consideration of factors not currently addressed in the model, including the constraints
31 with the current LNG unit operation [i.e., it is not efficient to use LNG for the loads below
32 2.6 MW or for short duration loads] and use of lower cost LNG to enhance winter storage
33 during drought periods.
34

35 YEC does not “alter” the model output. YECSIM simply generates a thermal energy value
36 (in KWh); YEC then allocates that generation number between our two available thermal
37 options (using factors as noted in the 2017-18 GRA, Appendix 3.4).

1 **TOPIC:**

2
3 **REFERENCE: YECSIM Model in GRA Presentation, February 12, 2018, page 25**
4 ***“Fundamentals of YECSIM – Methodology.”***

5
6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Please provide detailed analysis of why abandoning the first 5 load years and the
11 8th load year results in a more accurate forecast.

12
13 b) Please provide details of who developed this abandoning method.

14
15 **ANSWER:**

16
17 **(a) and (b)**

18
19 Please see the YECSIM User Manual provided as Appendix 2.4 of the Two Part ERA
20 Application. The length of the simulation period and the use of only certain years for
21 determining the simulation of results as adopted in the original model as developed by
22 KGS Group is reviewed at pages 108-09 of the User Manual. The need to remove certain
23 years is understood to be a normal element for hydro planning simulation models (see
24 discussion below from the User Manual).

25
26 The following are specifically noted for clarification:

- 27
- 28 • The YECSIM User Manual references a series of 8 years with a constant load
29 demand each year [in practice today there are 20 load years used];
 - 30
31 • The YECSIM User Manual notes that 8 years are needed so that certain “edge
32 effects” can be eliminated as summarized below:
33 “The effects of starting the reservoirs at a full stage on Jan 1 of the first load
34 year. This is unrealistic. Although it could be resolved by choosing a lower
35 starting water level that could be representative for comparative purposes
36 between simulations, it was considered more effective for the initial effects
37 to be eliminated by several years of operation. The end of the fifth year,

1 was found for all cases addressed, to have reservoir levels that were
2 identical. So the first five years are now considered as a “start-up phase”
3 that leads to the sixth and seventh years, which can be used to generate
4 system operation statistics that are not arbitrarily affected by the start-up
5 conditions in the first year.
6

7 The effects of the computation of the reservoir rule curves that protect
8 against the drawdown of water levels under existing licensed limits. The
9 rule curves are described in more detail below, but the point is that they
10 allow the reservoir to draw down to the lowest limit on Dec.31 of the last
11 load year. The backwards calculation from that point in time determines the
12 rule curve. This arbitrary assignment of the lowest reservoir level would
13 affect the simulations in an unrealistic way if not corrected. The means to
14 eliminate such effects were selected to consist of allowing one additional
15 years after the sixth and seventh years (i.e. Year 8) so that the last year
16 would not unrealistically influence the statistics in the two previous years.
17 This is a similar, but inverted, correction described in the bullet above.
18

- 19 • While the User Manual description above indicates that only two years are used to
20 determine model results [years 6 and 7], the workshop discussion indicated that
21 13 years are used today to determine model results. The first 6 load year
22 simulations [years 1-6] and the last load year simulation [Year 20] are removed
23 today from the averaging for LTAs.
24

25 As noted at page 1 of the User Manual – the model and methods used to determine model
26 results were developed by KGS Group. See response to YUB-YEC-1-3(a) from the 2014
27 DCF/ERA proceeding which notes that KGS Group staff has been actively involved in
28 understanding and applying similar models used for similar purposes in other hydro-
29 thermal electric power systems.

1 **TOPIC:**

2
3 **REFERENCE:** YECSIM Model in GRA Presentation, February 12, 2018, page 29
4 *“Fundamentals of YECSIM – Major Inputs for 2017/2018 GRA”*
5

6 **PREAMBLE:**

7
8 **QUESTION:**
9

10 a) Please explain why 35 years is the optimal number if historic inflows to use in the
11 YECSIM model.
12

13 b) Please provide details of any analysis undertaken to determine if more years of
14 inflow will add to or diminish the accuracy of the model.
15

16 c) Please provide analysis that the 35 years of inflows reflects the current trend in
17 climate change impacts.
18

19 d) Please update the YECSIM model results and resulting forecasts using inflows
20 from 1981 – 2017 and 1998 - 2017.
21

22 e) Please provide details of who developed this abandoning method.
23

24 **ANSWER:**
25

26 **(a), (b) and (c)**
27

28 The 35 water years are the years (1981 to 2015) for which relevant water data was
29 available when YECSIM was run for the current GRA forecasts, i.e., it is not asserted to
30 be an “optimal” number.
31

32 YECSIM and other similar models are run using the number of years of reliable water data
33 that are then available (the number of such years expands over time).
34

35 The data reflects what was recorded over the 35 years, including any climate change
36 impacts relevant to those years.

1 **(d)**

2
3 The YECSIM input files have not been updated to include water records for 2016 and
4 2017. The latest available input file uses water records from 1981-2015. Therefore, the
5 requested information with 1981-2017 or 1998-2017 inflows cannot be provided.

6
7 Table 1 below provides, for illustration purposes, the long-term average thermal
8 generation using average for 1981-2015 water years as used in the 2017-18 GRA, Table
9 2-2 compared to average of thermal generation for 1998-2015 water years.

LTA Thermal based on 1981-2015 Water Years [GRA Table 2.2, for 2018]	Average for 1998-2015 Water Years for illustrative comparison purposes
14,480 MW.h	12,022 MW.h

11
12 **(e)**

13
14 See response to UCG-YEC-2-7(a-b) which asked this same question.

1 **TOPIC:**

2
3 **REFERENCE:** YECSIM Model in GRA Presentation, February 12, 2018, page 32
4 *“Fundamentals of YECSIM – Major Outputs - 2017/2018 GRA”*

5
6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Please explain with analysis why 13 years of load simulations are used for
11 determining long-term averages.

12
13 b) Please provide details of the YECSIM thermal generation split between diesel and
14 LNG for the last 10 years.

15
16 **ANSWER:**

17
18 **(a)**

19
20 Please see response to UCG-YEC-2-7.

21
22 **(b)**

23
24 Please see response to UCG-YEC-2-6. YECSIM does not provide a split between diesel
25 and LNG.

1 **TOPIC:**

2
3 **REFERENCE: December 6, 2017 Application, page 2-2**

4
5 *“The ERA was established in 1993, when ST hydro generation*
6 *forecasts were still being adopted for GRA purposes, as a*
7 *retrospective payment calculation integrated into the wholesale rate*
8 *(RS 42), designed to ensure that YECL received a full pass-through*
9 *of all incremental costs or savings of diesel generation attributable*
10 *to higher or lower than forecast wholesale demand. As with the*
11 *DCF and its precedent fund (the LWRF), the ERA was only active*
12 *during the 1990s when the Faro Mine was in operation which*
13 *resulted in diesel generation accounting for 100% of any generation*
14 *change due to firm load changes. The basic requirement for the*
15 *ERA reflected the material variance per kW.h of wholesale in YEC*
16 *thermal generation costs (fuel plus variable O&M) versus the RS 42*
17 *Energy Charge. Given this variance, YEC required (when the Faro*
18 *Mine was operating) an ERA mechanism in order to recover a*
19 *material portion of its incremental diesel generation costs related*
20 *to an increase in wholesales above GRA forecasts; the ERA*
21 *mechanism also rebated to YECL the net savings that YEC*
22 *recovered when wholesales were less than GRA forecasts.”*

23
24 **PREAMBLE:**

25
26 **QUESTION:**

- 27
28 a) Please confirm that the ERA was designed assuming that all incremental costs
29 or savings related to diesel generation that are passed-through to YECL (now
30 AEY) would be passed through to YECL's customers. Please explain how
31 these costs or savings are to be passed-through to end-use customers.
32
33 b) Please explain what variable O&M costs would be included in thermal
34 generation costs. Please provide a breakdown of actuals levels of these costs
35 for the most recent year available.
36
37 c) Please confirm that the ERA was not designed to allow YEC to recover a

1 material portion of its incremental diesel generation costs related to an
2 increase in wholesales above GRA forecasts but rather all of the incremental
3 costs.

4
5 d) Please confirm that there is no way for YEC to double-recover variable O&M
6 costs through the ERA mechanism and rates approved by the YUB to recover
7 forecast O&M costs.

8
9 e) Please provide a chronological history of the ERA noting the drivers of each
10 adjustment calculation. Please provide explanations for differences in drivers
11 of each of these ERA calculations.

12
13 **ANSWER:**

14
15 **(a)**

16
17 Not confirmed. There was no pass through of ERA charges contemplated, or carried out,
18 to any retail customers when the ERA was designed and implemented in the 1990s.

19
20 **(b)**

21
22 In the 1990s, when the ERA was designed and implemented, variable O&M costs were
23 estimated and used (along with variable fuel costs) to establish run-out retail and industrial
24 rates. The same variable O&M costs were then used for the DCF and ERA at that time to
25 reflect the retail run-out rates. These variable O&M costs included estimates reflecting
26 lube oil, maintenance and other non-fuel diesel generation costs that tend to vary with the
27 amount of generator use.

28
29 YEC does not have recent estimates for variable O&M costs, or a useful current
30 breakdown of actual levels for such costs, as these are not currently included in any retail
31 rate, DCF, or ERA determinations.

32
33 **(c)**

34
35 The ERA as such was designed to recover a “material portion” of YEC’s incremental diesel
36 generation costs related to an increase in wholesales above GRA forecasts, i.e., the ERA
37 was designed to recover the portion of such costs not otherwise recovered by the Rate

1 Schedule 42 Energy Charge. The ERA was required to enable YEC thereby (through both
2 the ERA and the Energy Charge) to recover all of these incremental costs.

3
4 **(d)**

5
6 Confirmed.

7
8 **(e)**

9
10 This response provides excerpts of the response to UCG-YEC-1-2(a) filed as part of the
11 2014 DCF/ERA proceeding. This response addresses the chronological history of the ERA
12 up to the 2014 proceeding as reflected in relevant applications and Board Orders. The
13 ERA was introduced in the joint 1993/94 GRA of the Companies. ERA matters since the
14 2012/13 GRA have been addressed in subsequent proceedings, including the recently
15 concluded ERA Application Part 1 proceeding.

16
17 **Order 1992-4 [pages 9-10]**

18 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/27_boardorder1992_4.pdf

19 Board Order 1992-4 at page 10 notes:

20
21 At page 2-6 of YECL's Application it states:

22
23 "The wholesale rate, for the purposes of this Application, has been based
24 on an inter-utility transfer which allows YECL and YEC each to meet their
25 respective revenue requirements based on the retail rates as applied for
26 and the assumptions set out above with respect to Curragh rates."

27
28 The Board views the wholesale rate as a method of balancing revenues to costs
29 as between YECL and YEC and, accordingly, approves the Companies' method
30 of determining the wholesale rate and the structure of the proposed wholesale rate.

31
32 **Decision 1993-1-6 and 1993-1-7**

33 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/38_boardorder1993_6.pdf

34 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/39_boardorder1993_7.pdf

35 The Joint YEC/YECL 1993/94 General Rate Application noted as follows regarding the
36 changes to the wholesale rate included in the Application [page 3-9]:

1 The wholesale rate applicable to transfers between YEC and YECL has been
2 restructured to provide a more stable balance of costs and revenues between the
3 two companies.

4
5 The move to increase retail run-out rates to incremental energy costs has also
6 increased revenue volatility of YEC and YECL. As YEC is responsible for most
7 energy production and YECL is responsible for most retail sales, fluctuations of
8 retail sales now cause revenue changes at an incremental cost level for YECL that
9 is not balanced by a corresponding cost change in the current single block
10 wholesale energy rate. The converse problem occurs for YEC. Restructuring the
11 wholesale rate to allow periodic adjustments between forecast and actual
12 wholesale transfers at a rate equal to the retail run out rate restores the balance.
13 The new wholesale rate will cause adjustments in transfers between YECL and
14 YEC that balance the changes in revenues and costs caused by sales fluctuations
15 and will have no effect on retail sales.

16
17 Order 1993-1-6 approved revenue requirement amounts for 1993 and 1994 and ordered
18 the companies to design rates to collect these amounts. Order 1993-7 approved the rate
19 schedules requested in Decision 1993-1-6. Section 5 of Order 1993-1-7 [page 5-1] notes
20 as follows:

21
22 Section 9 of OIC 1991/62 requires that YEC wholesale rates charged to YECL be
23 sufficient to recover YEC costs that are not recovered from its other customers.
24 Rate Schedule 42 (Wholesale) has been calculated in accordance with this
25 requirement, based on proposed rates and forecast rate revenues for each year.
26 The proposed wholesale rate applicable to transfers from YECL to YEC (Rate
27 Schedule 42) has also been restructured, as described in the revised June 1993
28 GRA, to provide a more stable balance of costs and revenues between the two
29 companies in the event that YEC power sales to YECL vary from forecasts on an
30 annual basis.

1 In 1993, a determination of the total wholesale charge under Rate Schedule 42 will
2 be made at year end, based on forecast wholesale sales at the annualized rate of
3 7.502 c/kWh, and the reconciliation adjustment to reflect variances from the
4 forecast wholesale sales. A portion of the 1993 wholesale charge under Rate
5 Schedule 42, equal to \$1,590,300, will be accrued for payment to YEC on Rider K,
6 starting January 1, 1994 (the accrued amount reflects YECL's forecast retail
7 revenue shortfall in 1993, after recover of Rider H amounts in November and
8 December 1993).

9
10 The 7.765 c/kWh is the transfer wholesale rate for 1994, prior to any reconciliation
11 adjustment. Rider K will also be charged in addition to the 1994 wholesale rate
12 until an amount of \$1,590,300 has been collected.

13
14 The Order 1993-1-7 attached Rate Schedules (referred to as Schedule "A") which included
15 the revised Rate Schedule 42 (including the Energy Reconciliation Adjustment). The Order
16 approved Rate Schedule 42 which included the following provision for the Energy
17 Reconciliation Adjustment.

18
19 **Order 1994-8 and Order 1996-8**

20 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/50_boardorder1994_8.pdf

21 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/64_boardorder1996_8.pdf

22
23 Rate Schedule 42 (in the same form as approved in Order 1993-1-7) was approved in
24 Order 1994-8 and Order 1996-8.

25
26 Charges to YECL will be periodically adjusted to reconcile actual wholesale
27 purchases to test year forecast purchases. To the extent that actual wholesale
28 purchase fall short or exceed forecast wholesale purchases, an adjustment to the
29 YECL bills will be made at a rate equal to the approved run out rate for non-
30 government residential service for the Hydro zone. Such adjustment for shortfalls
31 in actual wholesale purchases will be limited to minus 10% of the forecast
32 wholesale purchases in any period.

33
34 **Order 1999-4 – Rate Schedule 42 Settlement**

35 http://yukonutilitiesboard.yk.ca/pdf/Board_Order_1999-4.pdf

1 The Board approved the Energy Charge Rate under Wholesale Rate 42 as applied for
2 and the terms of the Settlement Agreement. The Order notes as background (on page 1)
3 as follows:

4
5 Yukon Energy Corporation's April 28, 1998 Revised Application requested that
6 certain amendments be approved with respect to the wholesale rate applicable
7 during 1996 and 1997.

8
9 As this matter directly affects amounts paid to Yukon Energy Corporation and The
10 Yukon Electrical Company Limited pursuant to Rate Schedule 42 (Wholesale
11 Primary) for 1996 and 1997, and does not affect other ratepayers, Board Order
12 1998-5 agreed that the matter should be dealt with in a separate process after the
13 public hearing.

14
15 The Board agreed that the outstanding issues be resolved between the Companies
16 utilizing the British Columbia Utilities Commission negotiated settlement process
17 guidelines. The Companies reached a settlement on October 7, 1999 and requested as
18 follows (as summarized in Order 1999-4):

19
20 [That] Energy Charge Rate under Wholesale Rate Schedule 42 be approved at the
21 amount reflected in the Revised Application, being:

- 22
23 • 1996 – 6.755 cents/kWh; and
24 • 1997 – 6.840 cents/kWh.

25
26 The Companies provided a copy of the Settlement Agreement, clarifying certain items in
27 the Energy Reconciliation Adjustment mechanism in Rate Schedule 42 (The Settlement
28 Agreement and Mutual Release Concerning Outstanding Rate Schedule 42 Issues
29 provided as Appendix A to Order 1999-4).

30
31 The Board reviewed the Settlement Agreement and determined as follows (at page 1):

32
33 That no changes to the wording of Rate Schedule 42 are required but that the
34 clarifications are consistent with the intent of Rate Schedule 42.

1 **Order 2010-13 [page 38, page 41-42]**

2 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1159_Board%20Order%202010-13.pdf

4 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1158_Board%20Order%202010-13%20Appendix%20A.pdf

7 Page 38 of Order 2010-13 notes as follows regarding Rate Schedule 42:

9 161. Rate Schedule 42 is described as the rate provided for YEC sales to YECL.
10 YEC is unable to give a precise rate as it is dependent upon the ultimate rate
11 design selected.

13 162. The Board agrees with the Companies that Rate Schedule 42 should be
14 updated. However, the Board cannot approve this proposed rate schedule as it
15 currently is indeterminate. Therefore, based on the previous directions under rate
16 design, the Companies are to provide one proposal for Rate Schedule 42 that both
17 companies endorse, in the compliance filing arising from this Decision.

19 Page 41-42 of Order 2010-13 notes as follows regarding YECL's proposed Rider D
20 mechanism:

22 179. The Board took note of YECL's submission that details of the Rider D
23 mechanism, including the period in which the balance will be collected or refunded
24 to customers and the calculation of the rider amount will be explained in detail in a
25 Rider D Application. Further, if "within a 12 month period YECL accumulates
26 balances (plus or minus) in excess of 0.5% of total revenue requirement, YECL
27 anticipates that it will file a Rider D Application to true-up balances in order to avoid
28 material rate swings to Yukon customers."

30 180. The Board, in Board Order 2009-2, approved YECL's wholesale purchase
31 power deferral account:

33 The Board acknowledges that there was little debate regarding the deferral
34 accounts described in the Application, i.e. the Diesel Contingency Fund
35 and Rate from YEC. Therefore, the Board approves YECL's...deferral
36 accounts. [Footnote omitted]

181. Implicit in the Board's approval of the purchase power deferral account is the approval of a future rider to dispense of the accumulated balances in the deferral account.

182. The Board acknowledges that diesel is not forecast to be on the margin during the 2009 period and given the deferral account exists, Rider D may be applied for in 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 addressed. Conversely, if YECL determines that the balance in the deferral account is too large, YECL may file a separate Rider D Application at that time, providing all assumptions and calculations (including in electronic form), and over what term YECL proposes to dispense with the balance in the deferral account.

183. In respect of YECL's 2008-09 GRA, the Board notes that YECL's proposed purchase power deferral account request refers to "non-governmental residential service for the hydro zone."¹¹⁸ In this Application, YECL submitted that Rider D is applicable to all classes of service ¹¹⁹. Accordingly, the Board directs YECL, when it files its Rider D Application, to clarify for which rate class or classes the rider is applicable.

184. The Board denies YECL's proposed Rider D and proposed amendments to the ERA provision. The Board directs YECL to re-file its proposed amendments at the time of its Rider D filing.

Order 2011-05 – 2009 Joint Phase II Rate Application Rate Schedules [Pages 1-2]
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1227_Board%20Order%202011-05.pdf

On February 28, 2011, the Companies filed with the Board their compliance filing in respect of their 2009 Phase II Rate Application. The Board determined that the compliance filing was consistent with the directions given to the Companies in the Reasons for Decision attached as Appendix A to Board Order 2010-13, and the Board approved the Rate Schedules attached as Appendix A to this Board Order effective June 1, 2011.

1 **TOPIC:**

2
3 **REFERENCE: December 6, 2017 Application, pages 2-5**

4
5 *“The PPA Application indicates a potential increase in grid loads*
6 *over the next decade sufficient to sustain material forecast thermal*
7 *generation at LTA hydro generation, e.g., prior to any enhanced*
8 *renewable generation being implemented, incremental YEC LTA*
9 *thermal generation at 65% to 75% of the incremental generation is*
10 *needed to supply the VGC mine power requirements.”*
11

12 **PREAMBLE:**

13
14 **QUESTION:**

- 15
16 a) Please provide an update on the commencement of the delivery of grid electricity
17 to VGC Group and the percentage of incremental generation will be provided by
18 thermal generation.
19
20 b) Pursuant to Board Order 2015-01 and Order 2015-06, please provide details of
21 when YEC provided the YECSIM model and its results for testing by intervenors
22 and the Board.
23

24 **ANSWER:**

25
26 **(a)**

27
28 VGC Group has confirmed that it has the financing to proceed. The updated schedule is
29 currently being confirmed. YEC has no new information (from what was provided during
30 the PPA proceeding) on impacts of this mine on incremental thermal generation.
31

32 **(b)**

33
34 As reviewed in YEC’s December 6, 2017 ERA Application, Yukon Energy is committed to
35 providing appropriate access to the YECSIM forecasting model for testing by intervenors
36 and the Board so that the Board’s concerns regarding the model can be alleviated. In this
37 regard, Yukon Energy provided as Appendix 2.4 of the Two Part Application regarding the

1 ERA the YECSIM User Manual. Access to the User Manual enables the Board and
2 interveners to review fully the constraints, processes and operational rules of this model
3 for testing and assessment.

4
5 Yukon Energy also organized a workshop on the YECSIM model in order to provide Board
6 staff and intervenors with the opportunity to ask any specific questions regarding the
7 model, in order to clarify any issues or concerns related to YECSIM arising from the
8 2017/18 GRA, the Two Part ERA filing, and in particular the YECSIM User Manual
9 included in that filing. Yukon Energy staff reviewed at the workshop the use of model in
10 the GRA process to determine LTA thermal generation requirements; model inputs and
11 model outputs; and methodology for determining LTA forecast.

12
13 It is noted that the YECSIM model is a computer program that consists of thousands of
14 lines of computer code that are, for all the practical purposes, a translation of the
15 constraints, processes and rules into a language that computers can understand. Yukon
16 Energy has provided model information regarding model inputs and outputs as requested
17 by the Board or other parties in order to understand model results for the test years.

1 **TOPIC:**

2
3 **REFERENCE: December 6, 2017 Application, page 2-7**

4
5 *"The final step, following contingency fund implementation, is the*
6 *determination of the final Yukon Energy thermal generation fuel*
7 *costs for each fiscal year (i.e., the YEC cost after removing water*
8 *variability impacts) and the determination of the ERA related to any*
9 *flow through to AEY of YEC's wholesale net cost changes related to*
10 *wholesale changes from the GRA forecast."*

11
12 **PREAMBLE:**

13
14 **QUESTION:**

- 15
16 a) Please explain how and to whom YEC provides information related to actual
17 thermal generation fuel costs each year and the ERA calculation.
18
19 b) Please explain why YEC and AEY (and its predecessor YECL) could not agree on
20 an ERA mechanism and how it would be calculated.
21

22 **ANSWER:**

23
24 **(a)**

25
26 YEC's GRA filings, and annual filings (including Rider F, DCF and ERA filings in the past),
27 provide information related to actual thermal fuel costs each year and the DCF and ERA
28 calculations.

29
30 Matters related to the DCF and the ERA have been the subject of Board review since the
31 2014 DCF/ERA proceeding.

- 32
33 • With regard to the DCF, the approved DCF Term Sheet specifically requires YEC
34 to file the following with the YUB:
35 o An annual report detailing additions and deletions to the fund and a forecast
36 of water conditions for the next year, as well as a proposed rate rider to
37 refund/ collect any amount that exceeds the approved cap. The Term Sheet

1 notes that the Board will direct YEC on additions/ deletions to the fund and
2 on the proposed rate rider.

- 3 o Quarterly reports regarding the DCF calculation and DCF balance updates
4 based on interim determinations prior to a fiscal year end.

- 5
6 • Subsequent to the approval of the DCF in Order 2015-01 and Order 2015-03,
7 annual DCF filings were provided to the Board for 2015 and 2016. These are
8 publicly available on the Board's website at the following link:
9 <http://yukonutilitiesboard.yk.ca/reports/>. The 2016 Annual DCF filing was also
10 included as Attachment 3.5 of the 2017/18 GRA.

- 11
12 • The ERA mechanism is subject to Board approval. ERA charges for 2012 through
13 2016 are currently before the Board as part of the ERA Part 1 Application process.
14 Pursuant to Board Order 2018-02, matters related to LTA, DCF and the ERA for
15 the period 2017 forward are to be reviewed as part of the ongoing 2017/18 GRA.

16
17 **(b)**

18
19 The DCF and the ERA were both the subject of significant review as part of the 2012/13
20 GRA and the 2014 DCF/ERA proceeding, and the basis for disagreement was addressed
21 in detail in the 2014 DCF/ERA proceeding. The response to YUB-YEC-1-11 as provided
22 in the 2014 DCF/ERA Proceeding outlined the discussion process between YEC and
23 YECL leading up to the 2014 DCF/ERA Proceeding and why agreement on any single
24 issue was not possible. Attachment 1 to this response provides the referenced IR
25 response.

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
YUB-YEC-1-11

TOPIC: Joint Agreement

REFERENCE: YEC/YECL DCF-ERA Filings of January 31, 2014

PREAMBLE:

QUESTION:

a) With respect to the DCF and ERA materials, please confirm that the Companies (YEC and YECL) were not able to agree on any single item. If not confirmed, please explain.

b) Please provide YEC's opinion on what purpose the DCF and ERA mechanisms should serve. Please also indicate whether that purpose has been adequately served in the past.

ANSWER:

(a)

The discussion process between YEC and YECL to date has not taken place in a context where agreement on any single issue has been possible.

The discussions and document exchange between the two companies are outlined in Appendix A of the cover letter to YEC's January 31, 2014 Filing. The materials referenced in Appendix A of the cover letter that were prepared and distributed by YEC as part of this discussion process are provided in response to YUB-YEC-1-10.

- Yukon Energy's position throughout the discussions has been that the DCF and the ERA should continue (with adjustment to reflect changing conditions on the existing grid system and directions in Board Order 2013-01) as they are both necessary, reflect past precedents and practices and are in the interest of ratepayers.
- Yukon Energy summarized its initial understanding of YECL's issues and concerns in Appendix A to the May 17, 2013 response to intervenor comments

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
YUB-YEC-1-11

1 on the Compliance Filing. At that time, based on discussions that had occurred,
2 Yukon Energy understood that YECL's concerns related primarily to the ERA.
3 YEC was not aware of any material concerns with the DCF, until YECL provided
4 its proposal in October 2013.

5
6 In summary, these discussions focused primarily on the ERA. Despite attempts to
7 document YEC's position and relevant historical background relating to this position, plus
8 effort to understand YECL's concerns and some actual changes and refinements made
9 to YEC's proposal for the ERA as a result of these discussions, it is fair to observe that
10 the overall discussion ultimately did not move beyond the two very different positions set
11 out in the record from argument in the YEC 2012-13 GRA, i.e., YECL wanted YEC to
12 discontinue the ERA and institute a YEC deferral account, and YEC did not see any
13 basis whereby it could support this proposal. In the end, YEC's January 31, 2014 filing
14 attempted (as directed by the Board) to document with Options A and B the two
15 positions on this matter and the basis for YEC proposing Option A.

16
17 With regards to the DCF, when YEC became aware in October 2013 of YECL's proposal
18 to abandon the DCF, YEC could not see any basis for further discussion on this matter.
19 YEC's ability to reference YECL's proposal in its subsequent January 31, 2014 filing was
20 also very restricted, given that it had been provided only as confidential and without
21 prejudice basis. YEC's concerns regarding this proposal have subsequently been set out
22 in the June 30, 2014 supplementary filing.

23

24 **(b)**

25

26 With regard to the purpose of the DCF as established in 1996, please see Attachment
27 1.1 of Appendix 1.1 of YEC's January 31, 2014 Filing which notes at page A1.1-1 with
28 regard to the purpose and function of the DCF.¹

29

30 "The DCF operates to smooth customer rate changes and changes in forecast
31 diesel costs due to variability in existing grid hydro and wind generation. The fund
32 is only to be used for these purposes and is not to be accessed for other reasons
33 without prior YUB approval, including government subsidy of rates. Historically,
34 the DCF has operated to offset diesel generation cost changes only for the WAF

¹ The referenced comments reflect the original purpose per the 1996 Settlement Agreement (see Attachment 2 to YUB-YEC-1-2(a). Updates provided to the original DCF scope are noted as well at page A1.1-1 of the January 31, 2014 filing.

Application to Revise the
Diesel Contingency Fund ("DCF")
& Related Amendments
to the Energy Reconciliation Adjustment ("ERA")

Yukon Energy Corporation
YUB-YEC-1-11

1 system caused solely by variances from long-term average levels of WAF system
2 hydro and wind generation."
3

4 The DCF is required to account for variance in actual diesel generation due to variance
5 from long-term average levels of hydro and wind generation. In the past, the DCF (and
6 LWRF before it) adequately served this primary purpose; however, as documented in
7 response to UCG-YEC-1-6 (b and c), the DCF was also on occasion used for other
8 purposes.
9

10 The purpose of the ERA is summarized in Appendix 2 of YEC's January 31, 2014 Filing
11 (see page 2-2). Specifically, the ERA was established to ensure:
12

- 13 1. That YECL receives a full pass through of YEC's incremental costs or savings of
14 diesel generation that result from changes in the volume of YECL wholesale
15 purchases compared to the forecast approved by the YUB to establish the then
16 current single energy-only wholesale rate; and
17
- 18 2. That YEC is able to recover its costs from YECL (as required by OIC 1995/90,
19 Section 7(b)) when diesel generation is on the margin in the Hydro zone.
20

21 As established in 1993, the ERA in effect ensured that YECL's retail Hydro zone loads
22 would be served by YECL under the same risk profile as all other YECL loads in Yukon.
23 When YECL's loads vary and this variation in load drives changes in the quantities of
24 diesel generation required, YECL would carry the cost (or capture the saving) that
25 results from these diesel generation changes.

1 **TOPIC:**

2
3 **REFERENCE:** December 6, 2017 Application, page 2-8

4
5 *“Regardless of which option is adopted, however, the following are*
6 *required due to the inter-relationships between GRA forecasts,*
7 *thermal generation cost or contingency fund account mechanisms,*
8 *and wholesale rate mechanisms:*

- 9
10
 - 11 • *A thermal cost or contingency fund account mechanism similar*
12 *to the DCF is required to address actual variances of thermal*
13 *generation costs in any year from the latest GRA forecast due*
14 *to water variances from GRA forecasts, whether those*
15 *forecasts are based on ST or LT hydro; and*
 - 16 • *A wholesale rate mechanism similar to the ERA is required to*
17 *ensure, in accordance with OIC 1995/90 and the direction of the*
18 *Court of Appeal, that AEY receives a full pass-through of all*
19 *incremental YEC costs or savings of thermal generation*
20 *attributable to higher or lower than forecast wholesale demand.”*

21
22 **PREAMBLE:**

23
24 **QUESTION:**

- 25
26 a) Please confirm that the requirements outlined in YEC’s evidence are simply the
27 opinion of YEC and have not been determined as requirements by the YUB.
28
29 b) Please confirm that the direction from the Court of Appeal was not to ensure that
30 AEY receives a full pass-through of all incremental costs or savings but that a
31 wholesale rate be set that enables YEC to recover all of its diesel generation costs
32 including any net DCF payment made by YEC attributable to AEY’s above-forecast
33 wholesale purchases of electricity.

1 **ANSWER:**

2
3 **(a)**

4
5 Not confirmed – the matters addressed in the referenced quotation are not simply YEC
6 opinions.

- 7
- 8 • Regulatory precedent in Yukon (reflecting YUB determinations), as well as
9 elsewhere, provides ample support for the basic principle that costs related to
10 water variation are ratepayer risks; and that in order to mitigate impacts on
11 ratepayers a contingency fund mechanism is necessary. Please see response to
12 YUB-YEC-2-2(c) for detailed review of relevant GRA filings and Board Orders
13 regarding the principle that risk of low water conditions variance relative to GRA
14 forecasts, as regards added cost of thermal generation, is borne by customers of
15 the utility with related determinations on contingency fund account mechanisms
16 with both ST and LTA hydro forecasts. See response to YUB-YEC-2-9(e) and
17 YUB-YEC-2-31(c) and (d) regarding contingency fund approaches used with
18 regard to water-related hydro generation variances in other Canadian jurisdictions.
19
 - 20 • As reviewed in paragraph 17 of the Yukon Court of Appeal judgement, Section 7
21 of OIC 1995/90 directs the Board to fix rates of Yukon Energy for the wholesale
22 customer that are "...sufficient to enable Yukon Energy Corporation to recover its
23 costs that are not recovered from its other customers." Paragraph 71 of the Court
24 of Appeal Decision directs the Board "...to set a wholesale rate that enables Yukon
25 Energy to recover all of its diesel generation costs, which include any net DCF
26 payment made by Yukon Energy attributable to Yukon Electrical's above-forecast
27 wholesale purchases of electricity." In summary, a mechanism such as the ERA is
28 required to enable YEC to recover all thermal generation related costs (including
29 related YEC payments required to be made into the DCF) attributable to the
30 electricity sold to its wholesale customer, including any such costs attributable to
31 AEY's above-forecast wholesale purchases of electricity.

32
33 **(b)**

34
35 It is unclear what distinction the question is seeking to raise, beyond the fact that the Court
36 of Appeal Decision did not address any requirement for the wholesale rate to pass-through

1 all incremental savings of thermal generation attributable to lower than forecast wholesale
2 demand.

3
4 The response to (a) above quotes the Court of Appeal's direction in paragraph 71 of its
5 judgement. The Court of Appeal's direction addresses the overall requirement to set a
6 wholesale rate that enables Yukon Energy to recover all of its diesel generation costs,
7 which include any net DCF payment made by Yukon Energy attributable to Yukon
8 Electrical's above-forecast wholesale purchases of electricity. Clearly, this direction
9 requires that the wholesale rate provide for a full pass-through of all incremental YEC costs
10 of thermal generation attributable to higher than forecast wholesale demand. Based on
11 regulatory precedent in Yukon regarding the ERA, Yukon Energy also understands this
12 direction requires that the wholesale rate provide for a full pass-through of all incremental
13 YEC savings of thermal generation attributable to lower than forecast wholesale demand.

14
15 The Court of Appeal Decision also notes as follows at paragraphs 62 and 70:

16
17 [62] In sum, s. 7 of the OIC directs the Board to fix wholesale rates sufficient to
18 enable Yukon Energy to get back everything it reasonably paid for generating the
19 electricity it sells to Yukon Electrical and would not otherwise recover from other
20 customers. In my view, this is the single available reasonable interpretation of s. 7
21 of the OIC. Accordingly, the Board was obliged to adopt and apply it in fixing the
22 rate for Yukon Energy's wholesale electricity sales to Yukon Electrical: McLean v.
23 British Columbia (Securities Commission), 2013 SCC 67 at para. 38.

24
25

26
27 [70] In my view, given the foregoing, the Order contravenes s. 7 of the OIC and the
28 decision was unreasonable. It does not fix a rate for Yukon Electrical's wholesale
29 purchases that enables Yukon Energy to get back everything it reasonably paid
30 for the electricity. More specifically, the Order fixes a rate that does not enable
31 Yukon Energy to recover from Yukon Electrical its reasonable net DCF payment
32 attributable to above-forecast wholesale purchases, which payment is part of its
33 diesel generation costs.

1 **TOPIC:**

2
3 **REFERENCE:** December 6, 2017 Application, page 2-9

4
5 *"The Board to date has consistently accepted and approved the*
6 *inter-relationships between hydro generation forecasts as used for*
7 *GRA purposes and the thermal cost or contingency fund account*
8 *mechanism needed to address actual variances of thermal*
9 *generation costs in any year from the latest GRA forecast due to*
10 *water variances from GRA forecasts."*

11
12 **PREAMBLE:**

13
14 **QUESTION:**

- 15
16 a) Please provide details of all Board Orders in which the YUB specifically approved
17 the inter-relationships between hydro generation forecasts as used for GRA
18 purposes and the thermal cost or contingency fund account mechanism needed
19 to address actual variances of thermal generation costs in any year from the latest
20 GRA forecast due to water variances from GRA forecasts.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Please see response to YUB-YEC-2-2(c).

1 **TOPIC:**

2
3 **REFERENCE:** *Reference: December 6, 2017 Application, page 2-9*

4
5 *“A fundamental principle of utility rate regulation in Yukon is that*
6 *ratepayers are to bear the risks related to water variability.”*
7

8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) Please provide specific references to Board Orders or legislation that confirms
13 YEC's claim that ratepayers bearing the risk related to water availability is a
14 fundamental principle of utility rate regulation in the Yukon.
15

16 **ANSWER:**

17
18 **(a)**

19
20 Please see response to YUB-YEC-2-2(c) for detailed review of relevant GRA filings and
21 Board Orders regarding the principle that risk of low water conditions variance relative to
22 GRA forecasts, as regards added cost of thermal generation, is borne by customers of the
23 utility. See response to YUB-YEC-2-9(e) and YUB-YEC-2-31(c) and (d) regarding
24 contingency fund approaches used with regard to water-related hydro generation
25 variances in other Canadian jurisdictions.

1 **TOPIC:**

2
3 **REFERENCE: December 6, 2017 Application, page 2-10**

4
5 *“Board jurisdiction with regard to Yukon electricity utilities is tied, in*
6 *the absence of specific directions from the Minister or by OIC, to*
7 *the determination of rates and related revenue requirements.*
8 *Accordingly, Board review of how YEC proposes to address the*
9 *DCF, ERA, wholesale rates and LTA hydro generation forecasts for*
10 *GRA purposes for the period 2017 forward is tied to Board*
11 *determinations on rates and related revenue requirements.”*

12
13 **PREAMBLE:**

14
15 **QUESTION:**

- 16
17 a) Please confirm that the YUB also has the jurisdiction to: (1) set just and reasonable
18 standards, classifications, regulations, practices, measurements, or services to be
19 observed, provided, or followed by a public utility; (2) determine the areas to which
20 a public utility shall provide service, and requiring the public utility to establish,
21 construct, maintain, and operate any reasonable expansion of its existing services;
22 (3) determine the conditions that may be imposed by a public utility to establish,
23 construct, maintain, or operate an expansion of its existing services; (4) order and
24 declare the terms of the joint use of utility facilities; and (5) inquire into, hear, and
25 determine any matter or thing respecting the production, transmission, delivery, or
26 furnishing of electricity or gas to the public.

27
28 **ANSWER:**

29
30 **(a)**

31
32 Part 2 of the ERA Application and the current 2017-18 GRA address matters related to
33 the Board's determination of rates and related revenue requirements. These applications
34 do not raise questions regarding other aspects of the Board's jurisdiction under the *Public*
35 *Utilities Act*. In any event, the Board's jurisdiction is as set out in the Act.

1 **TOPIC:**

2
3 **REFERENCE: December 6, 2017 Application, page 2-11**

4
5 *“Yukon Energy is also not aware of any applicable alternative to*
6 *the requirement for an ERA wholesale rate mechanism that flows*
7 *through to AEY the YEC wholesale net cost changes related to*
8 *wholesale changes from the GRA forecast.”*
9

10 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
11 **page 5**

12
13 *“As per Order 2017-08, DCF references are removed for the test*
14 *years; however, as reviewed in Appendix 2.2 of the December 6,*
15 *2017 ERA Application, some form of contingency fund account*
16 *would continue to be required if the Alternative GRA Forecast was*
17 *to be used to set rates.”*
18

19 **PREAMBLE:**

20
21 **QUESTION:**

- 22
23 a) Please confirm whether YEC is aware of the use of deferral accounts that
24 accumulate variances between forecast and actual costs.
25
26 b) Is YEC aware of any jurisdiction where a deferral account is used to track the
27 difference between forecast and actual costs of generation?
28
29 c) Is YEC aware of the Global Adjustment mechanism used on Ontario?
30
31 d) Please explain how Yukon ratepayers would benefit from “some form of
32 contingency fund account” that YEC has determined is required.

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 Yukon Energy is aware of the use of deferral accounts that deal with variances between
6 forecast and actual costs; Yukon Energy is also aware of jurisdictions where deferral
7 accounts are used to track variances between forecast and actual costs of generation.
8 YEC has reviewed, in past proceedings on the DCF and ERA, the range of such
9 mechanisms in other hydro-electricity jurisdictions in Canada that address cost impact
10 issues related to water variance versus load variance impacts from GRA forecasts. None
11 of these alternatives have been considered to be reasonably applicable to the
12 requirements as they have evolved in this Yukon jurisdiction. Please also see response to
13 YUB-YEC-2-9 and YUB-YEC-2-31.

14
15 **(c)**

16
17 Yukon Energy is not specifically aware of the Global Adjustment mechanism used in
18 Ontario. An initial review of publicly available information indicates limited relevance of
19 this mechanism for the current proceeding.

20
21 Cursory review of available information indicates that the Global Adjustment (GA) was
22 established by the Ontario government in 2005 to cover the cost of providing adequate
23 generating capacity and conservation programs for Ontario. The net impact of the GA
24 appears to be an added charge on customer bills so that electricity generating
25 companies receive a guaranteed price for the electricity that they produce.

26
27 The Ontario Energy Board notes as follows regarding the specific GA charge that
28 appears on customer bills in that jurisdiction¹:

29
30 Most electricity generating companies get a guaranteed price for the electricity
31 that they produce. The Global Adjustment is the difference between that
32 guaranteed price and the money the generators earn in the wholesale
33 marketplace. The Global Adjustment also covers the costs of some conservation
34 programs.

¹ See <https://www.oeb.ca/rates-and-your-bill/electricity-rates/understanding-your-electricity-bill>.

1 All electricity consumers have to pay a share of the Global Adjustment. The time-
2 of-use and tiered electricity rates charged by your electricity utility already include
3 an estimate of the Global Adjustment. If you sign up for a contract with an energy
4 retailer, you have to pay your share of the Global Adjustment on top of the
5 contract price. The Global Adjustment will also appear as a separate line on your
6 bill (see above sample bills).

7

8 **(d)**

9

10 Please see response provided to YUB-YEC-2-2(c) and YUB-YEC-2-3(c) regarding the
11 history and basis for the LWRF and the DCF. The DCF was approved after a Negotiated
12 Settlement agreement that included customer representatives.

13

14 In summary, contingency funds such as the LWRF and the DCF have been developed
15 and approved as an effective way to smooth customer rate changes from thermal
16 generation cost impacts caused by fluctuation in hydro generation due to water
17 conditions (as well as due to changes in wind conditions). The focus of these
18 contingency fund mechanisms is on providing enhanced rate stabilization for all Yukon
19 ratepayers, i.e., in Yukon all ratepayers are affected by changes in thermal generation
20 costs in the hydro rate zone.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission, pages**
4 **2-6 and 2-17**

5
6 *"Firm wholesales for 2017 are forecast in Table 2.1 at 309.0 GW.h,*
7 *which is 8.7 GW.h higher than the original AEY GRA forecast for 2017*
8 *and 4.7 GW.h lower than the AEY Compliance Filing forecast in*
9 *response to Board Order 2017-01. This forecast reflects forecast AEY*
10 *grid firm load at 317.6 GW.h less forecast AEY long-term average*
11 *generation at 8.6 GW.h."*

12
13 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission, page 2-**
14 **13**

15
16 *"It is assumed in the Alternative GRA Forecast that 60% of ST thermal*
17 *generation requirements as forecast for the test years will be met by*
18 *natural gas generation supplied by liquefied natural gas (LNG), with the*
19 *balance (40%) supplied by diesel generation. This assumption reflects*
20 *the tendency for diesel generation to dominate smaller and shorter*
21 *duration thermal generation, and the lack of any useful additional*
22 *assessments as to forecast allocation for each test year. There is*
23 *considerable risk, absent any change in the forecast total Firm Load*
24 *Generation, that the LNG/diesel allocation in each test year could be*
25 *very different than assumed in this Alternative GRA Forecast."*

26
27 **PREAMBLE:**

28
29 **QUESTION:**

- 30
31 a) Please provide updated Tables 2.1 and 2.2 showing 2017 actuals and an updated
32 2018 forecast.
33
34 b) Please provide and explain the analysis which resulted in the split of thermal
35 generation changing from 90/10 LNG/diesel to 60/40 LNG/diesel and the impact
36 this had on costs.

1 **ANSWER:**

2
3 **(a)**

4
5 In response to YUB-YEC-1-3, an updated 2017 firm wholesales forecast was provided
6 (along with related updates to 2018 and other GRA elements) consistent with the 314.2
7 GW.h accepted by the Board in Order 2017-03.

8
9 Attachment 1 provides a revised Table 2.1 with 2017 preliminary actual.

10
11 Please see response to CW-YEC-2-1(a and b) for discussion of preliminary actual versus
12 forecast sales for 2017 and the updates available on 2017 preliminary actual for
13 generation (Table 2.2 as such has not been updated). YEC does not have an updated
14 GRA forecast for 2018.

15
16 Please also see response to UCG-YEC-2-42.

17
18 **(b)**

19
20 The basis for the 90/10 LNG/ Diesel generation mix for the LTA forecast is outlined in
21 YUB-YEC-2-6 (c) and YUB-YEC-2-19(b); as well as in Appendix 3.4 of the 2017/18 GRA
22 as well as in the response to YUB-YEC-1-25; YUB-YEC-1-43; YUB-YEC-1-36; YUB-YEC-
23 1-39 and JM-YEC-1-13.

24
25 YUB-YEC-2-21 notes that the 60:40 ST alternative LNG/ Diesel generation mix was
26 provided as a reasonable ST forecast, notwithstanding the uncertainties noted, and the
27 cost impacts of this were provided in the ERA Application Part 2 (Appendix 2.2). However,
28 there is no basis to consider this mix to be reasonable for the purpose of the LTA GRA
29 forecast. The time scope relevant for the ST versus LTA forecasts is totally different as
30 regards expected hydro and thermal generation, and therefore the ST forecast LNG/diesel
31 mix has no relevance to the LTA forecast LNG/diesel mix.

32
33 See also YUB-YEC-2-22 and JM-YEC-2-4.

Attachment 1 - Revised Table 2.1

**Table 2.1 - Revised to reflect Updated Forecast and Preliminary Actuals for 2017
Summary of Customers, Energy Sales and Revenues**

Line No.	Description	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	Updated Forecast	Preliminary Actual	Forecast
							2017	2017	2018
1	Residential								
2	Customers	1,536	1,559	1,561	1,588	1,609	1,624	1,653	1,635
3	Sales in MWh	12,408	13,385	13,327	13,121	13,390	13,622	14,965	13,719
4	MWh sales per customer	8.1	8.6	8.5	8.3	8.3	8.4	9.1	8.4
5	Revenue (\$000s)	1,815	1,943	1,938	1,913	1,956	2,002	2,203	2,016
6	Cents per KWh	14.6	14.5	14.5	14.6	14.6	14.7	14.7	14.7
7	General Service								
8	Customers	467	470	475	480	488	490	499	490
9	Sales in MWh	22,620	22,283	23,616	24,551	24,994	25,318	26,132	25,436
10	MWh sales per customer	48.4	47.4	49.8	51.1	51.2	51.7	52.4	51.9
11	Revenue (\$000s)	3,735	3,621	3,894	4,048	4,180	4,036	4,350	4,054
12	Cents per KWh	16.5	16.3	16.5	16.5	16.7	15.9	16.6	15.9
13	Industrial								
14	Sales in MWh	40,592	40,513	36,302	37,186	41,169	38,219	43,419	38,219
15	Revenue (\$000s)	4,787	4,595	3,958	4,159	4,478	4,198	4,829	4,198
16	Cents per KWh	11.8	11.3	10.9	11.2	10.9	11.0	11.1	11.0
17	Street lights								
18	Sales in MWh	279	281	290	290	256	225	228	214
19	Revenue (\$000s)	88	89	92	92	88	58	88	56
20	Cents per KWh	31.5	31.6	31.6	31.6	34.5	26.0	38.6	26.0
21	Space lights								
22	Sales in MWh	15	14	14	14	14	12	12	12
23	Revenue (\$000s)	4	4	4	4	4	3	3	3
24	Cents per KWh	26.7	26.5	26.6	25.9	26.0	22.5	28.7	22.5
25	Total Company - Firm Retail & Ind.								
26	Customers	2,003	2,029	2,036	2,068	2,098	2,114	2,152	2,126
27	Sales in MWh	75,914	76,476	73,549	75,162	79,823	77,395	84,756	77,599
28	Revenue (\$000s)	10,429	10,252	9,886	10,214	10,705	10,297	11,474	10,327
29	Cents per KWh	13.7	13.4	13.4	13.6	13.4	13.3	13.5	13.3
30	Wholesale sales								
31	Sales in MWh	307,147	307,927	295,284	297,961	301,207	314,234	328,426	314,753
32	Revenue (\$000s)	25,487	25,546	24,503	24,725	24,994	26,075	27,253	26,118
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	Total Company - Firm								
35	Sales in MWh	383,061	384,403	368,833	373,122	381,030	391,629	413,182	392,352
36	Revenue (\$000s)	35,916	35,798	34,388	34,939	35,700	36,372	38,727	36,445
37	Cents per KWh	9.4	9.3	9.3	9.4	9.4	9.3	9.4	9.3
38	Secondary								
39	Sales in MWh	0	3,959	5,415	7,030	4,835	11,464	8,385	11,464
40	Revenue (\$000s)	0	275	410	544	371	642	461	642
41	Cents per KWh	0.0	6.9	7.6	7.7	7.7	5.6	5.5	5.6
42	Total Company								
43	Sales in MWh	383,061	388,363	374,248	380,152	385,865	403,093	421,567	403,816
44	Revenue (\$000s)	35,916	36,073	34,798	35,483	36,071	37,014	39,188	37,087
45	Cents per KWh	9.4	9.3	9.3	9.3	9.3	9.2	9.3	9.2
46	Rider J (\$000s)	6,163	6,288	6,167	6,172	6,342	6,447	7,883	6,456
47	Total Sales Revenues¹	42,079	42,360	40,966	41,655	42,413	43,461	47,071	43,543
48	Total Sales Revenues excluding secondary sales	42,079	42,086	40,556	41,111	42,042	42,819	46,610	42,901

Notes:

1. Excludes revenues from other revenues.

2. 2017 Preliminary Actuals are unaudited actuals based on preliminary results and subject to change.

3. 2017 Updated Forecast to reflect AEY Compliance Firm Wholesales for 2017, per YUB-YEC-1-3.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 2-15**

5
6 *"The forecast dependable capacity shortfall based on the single*
7 *contingency (N-1) criterion is forecast at 7.6 MW for 2017 and 8.7 MW*
8 *for 2018."*
9

10 **PREAMBLE:**

11
12 **QUESTION:**

- 13
14 a) Please provide the actual dependable capacity shortfall for 2017 and an updated
15 forecast for 2018.
16

17 **ANSWER:**

18
19 **(a)**

20
21 For the single contingency (N-1) criterion, the GRA forecast the dependable capacity
22 shortfall for 2017 at 7.6 MW based on the following:
23

- 24 • Forecast non-industrial peak for the integrated grid of 84.3 MW (91.8 MW total
25 forecast peak less 6.5 MW for Minto mine and 1 MW for Haines Junction [that is
26 not supplied by grid under N-1 condition]); less
27
28 • Dependable grid capacity at 76.7 MW assuming the N-1 event (115.0 MW less
29 37.0 for N-1 affecting Aishihik and 1.3 MW for Haines Junction [that is not available
30 to the grid under N-1 condition]).
31

32 YEC's reported peak grid load in December 2017 was 92.7 MW, about 0.9 MW higher
33 than the GRA forecast. For this update, it is assumed that this reflected the net increase
34 for non-industrial load peak excluding Haines Junction.
35

36 Since the GRA, YEC by early December 2017, had secured 8 MW of short-term diesel
37 generation dependable capacity (see response to CW-YEC-2-8). As a result, YEC's net

1 actual dependable capacity shortfall as of December 2017 was reduced from the forecast
2 7.6 MW to the actual 0.5 MW [7.6+0.9-8].
3
4 YEC does not currently have an updated forecast of peak load for 2018. However, YEC
5 now forecasts that there will not be a dependable capacity shortfall in December 2018
6 based on the single contingency (N-1) criterion. This change from the GRA forecast
7 shortfall of 8.7 MW is the result of forecast increase in dependable capacity for December
8 2018 of approximately 12 MW (includes 4 MW for LNG Third Engine that is now forecast
9 to be in-service by December 2018, and 8 MW of mobile diesel units).

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-2**

5
6 *Table 3.1: Yukon Energy Revenue Requirement*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.1 showing 2017 actuals and any updated 2018
13 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-4**

5
6 *Table 3.2: Fuel and Purchased Power*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.2 showing 2017 actuals and any updated 2018
13 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Please see response to CW-YEC-2-1(a) for an update for preliminary actual 2017 results
20 for fuel and purchase power costs. There are no updates to the 2018 forecast in Tab 2,
21 Tab 3, Tab 5 and Tab 7 as included in Yukon Energy's June 2017 General Rate
22 Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-6**

5
6 *Table 3.3: Non-Fuel Operating and Maintenance Expenses*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) Please provide an updated Table 3.3 showing 2017 actuals and any updated 2018
13 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-7**

5
6 *Table 3.4: Employee Complement History*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.4 showing 2017 actuals and any updated 2018
13 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-9**

5
6 *Table 3.5: Production Costs*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.5 showing 2017 actuals and any updated 2018
13 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-10**

5
6 *Table 3.6: Transmission Costs*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.6 showing 2017 actuals and any updated 2018
13 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-11**

5
6 *Table 3.6.1: Brushing Costs*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) Please provide an updated Table 3.6.1 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-12**

5
6 *Table 3.7: Distribution Costs*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.7 showing 2017 actuals and any updated 2018
13 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-12**

5
6 *Table 3.8: General Operating and Maintenance*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.8 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-14**

5
6 *Table 3.9: Administration*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.9 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-15**

5
6 *Table 3.10: Insurance and Reserve for Injuries and Damages*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) Please provide an updated Table 3.10 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-16**

5
6 *Table 3.11.1: RFID Continuity Schedule*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) Please provide an updated Table 3.11.1 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-17**

5
6 *Table 3.12: Property Taxes*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.12 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-18**

5
6 *Table 3.13: Mid-Year Net Rate Base*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.13 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-19**

5
6 *Table 3.14: Depreciation and Amortization*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.14 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-21**

5
6 *Table 3.14.1: Hearing Cost Reserve Account Continuity Schedule*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.14.1 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-21**

5
6 *Table 3.14.2: Deferred Vegetation Management Continuity Schedule*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.14.2 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 3-22**

5
6 *Table 3.15: Reserve for Site Restoration Continuity Schedule*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) Please provide an updated Table 3.15 showing 2017 actuals and any updated
13 2018 forecast.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Final actual results for 2017 are not available and as such requested updates to GRA
20 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
21 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
22 in Yukon Energy's June 2017 General Rate Application filing.

23
24 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission**

4
5 *Appendix 3.3 – Key Performance Indicators*

6
7 **PREAMBLE:**

8
9 **QUESTION:**

10
11 a) Please provide updates to all tables and charts in this report that show 2017 actuals
12 and any updated 2018 forecast.

13
14 **ANSWER:**

15
16 **(a)**

17
18 YEC has not yet prepared updates for actuals for KPIs in this appendix. It is noted that
19 2017 actual KPIs will not be available until after the 2017 financial statements are
20 approved; and YEC does not forecast KPIs.

1 **TOPIC:**

2
3 **REFERENCE:** **December 18, 2017 Alternative GRA Forecast Submission**
4 ***Appendix 3.5 – Diesel Contingency Fund (“DCF”) 2016 Annual***
5 ***Report***
6

7 **PREAMBLE:**

8
9 **QUESTION:**

10
11 a) Please provide the 2017 DCF Annual Report.
12

13 **ANSWER:**

14
15 **(a)**

16
17 YEC expects to file the 2017 DCF Annual Report next week. The following provides the
18 core information related to the 2017 DCF Annual Report on DCF activities.
19

20 Matters related to the DCF, the ERA and LTA for the period 2017 forward are currently
21 being considered as part of the 2017/18 GRA proceeding pursuant to Board direction
22 provided in Order 2017-08 and 2018-02. As such, it is expected that the 2017 DCF Annual
23 Report material will remain interim until the Board's final Order is issued regarding the
24 2017/18 GRA proceeding.
25

26 Tables referenced below are provided at the end of this response.
27

28 **DCF Calculations and Balance as of December 31, 2017**

29
30 Table 1 provides DCF calculations and balance as of December 31, 2017, and Table 2
31 provides a DCF Continuity Schedule for the years 2012 to 2017. Table 3 provides Rider
32 E calculation. Monthly calculations for 2017 are provided in Table 4.
33

34 In summary, these tables indicate as follows regarding the annual DCF calculations and
35 balance for 2017:

- 1 • Based on actual annual load for 2017 and the proposed DCF Term Sheet in the
2 GRA, the "expected" (i.e., based on long term average water conditions) thermal
3 requirement for 2017 is 26.806 GW.h (Table 1, L15);
4
5 o LNG is assumed (per the GRA) to displace 90% of the 2017 expected long-
6 term average thermal requirements, subject to not exceeding total
7 expected thermal less actual net diesel generation (excluding RFID, capital
8 and maintenance).
9
- 10 • Actual annual thermal generation requirement for 2017 (net of LNG and diesel
11 charged to capital, RFID and maintenance) was 13.261 GW.h, including 3.623
12 GW.h diesel and 9.638 GW.h LNG.
13
- 14 • The resulting overall gap between expected and actual thermal generation for
15 2017 equals 13.545 GW.h, all of which is assumed to be LNG generation per GRA
16 proposed determinations.
17
- 18 • The resulting payment required from YEC into the DCF for 2017 is \$1.987 million.¹
19
- 20 • Based on the above, and the DCF balance at the end of the previous year net of
21 the forecast impact of the current Rider E rebate applicable until April 30, 2018,
22 the forecast DCF fund balance at 2017 year-end that affects determination of a
23 new Rider E is \$7.633 million.²
24

25 **Updated Rider E**

26
27 In Order 2015-06, the Board directed that YEC refund DCF contributions in excess of the
28 \$8.0 million cap through a rate rider applicable to all firm sales throughout the Yukon (Rider
29 E). Based on the 2015 Annual filing, the Board's letter of April 6, 2016 reinstated the earlier
30 DCF rebate at 0.68 cents/kWh on an interim basis, effective May 1, 2016.

¹ Calculation assumes 100% LNG. The LNG price of \$0.1467 per kW.h is forecast per GRA.

² See Table 2. The DCF balance at December 31, 2017 net of refunds is \$8.697 million. Forecast refunds in 2018 for January through April equal \$1.064 million. The forecast DCF balance as at April 30, 2018 is therefore \$7.633 million.

1 The DCF calculations and balance update for 2017 (Tables 1 and 2) forecast DCF balance
2 at less than the \$8.0 million cap as of April 30, 2018.³ Based on this forecast, no Rider E
3 rebate is appropriate after April 30, 2018 and the Rider E refund to ratepayers is therefore
4 proposed at 0.00 cents/kW.h for implementation from May 1, 2018 to March 31, 2019. For
5 further detail regarding the Rider E calculation see Table 3.

³ Considering the implementation effective April 1, 2018 is not achievable, the new rates proposed to be effective May 1, 2018. The current Rider E at 0.68 cents/kW.h is assumed to continue until April 30, 2018.

1

Table 1: DCF Calculations for 2012-2017

Line No							Notes
L1	Fuel Cost per kW.h, Diesel	28.71	28.71	28.71	28.71	28.71	26.33 cents/kW.h
	Fuel Cost per kW.h, LNG				18.83	18.17	14.67 cents/kW.h
2012/13 GRA Compliance Filing & 2017-18 GRA Average Fuel cost for 2017. Actual for 2015 & 2016; 2017-18 GRA Fuel cost for 2017.							
Calculation of Diesel or LNG Cost to Charge (Refund) DCF							
		2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Preliminary Actuals
<i>Assumptions</i>							
L2	YEC Grid load	424,541	419,173	396,498	410,316	412,776	446,458 MW.h
L3	Fish Lake	3,388	3,687	10,247	9,180	8,033	7,103 MW.h
L4=L2+L3	Total Grid load	427,929	422,860	406,745	419,495	420,809	453,561 MW.h
Actual net of secondary sales (with losses) Fish Lake generation							
<i>Assumed Actual Generation Sources</i>							
L5=L3	YEC Fish Lake	3,388	3,687	10,247	9,180	8,033	7,103 MW.h
L6	YEC Hydro	421,039	416,987	394,595	404,797	406,136	431,952 MW.h
L7	YEC Thermal	3,057	1,910	1,566	4,868	6,131	14,474 MW.h
	Diesel	3,057	1,910	1,566	3,574	2,879	4,618
	LNG				1,295	3,251	9,856
L7a	YEC Diesel/LNG charged to capital, RFID and maintenance	373	872	951	2,047	1,043	1,213
	Diesel	373	872	951	1,345	586	995
	LNG				702	457	218
L7b=L7-L7a	YEC Net Diesel/LNG	2,683	1,037	615	2,822	5,087	13,261
	Diesel	2,683	1,037	615	2,229	2,293	3,623
	LNG	-	-	-	593	2,794	9,638
L8	YEC Wind	445	277	337	650	509	33 MW.h
L9=L5+L6+L7+L8	Total Grid load	427,929	422,860	406,745	419,495	420,809	453,561 MW.h
Wind generation							
<i>Expected Generation Sources</i>							
L10	YECL Fish Lake (expected)	4,380	4,380	8,730	8,730	8,730	8,536 MW.h
L11	YEC Wind (expected)	239	238	238	238	238	580 MW.h
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	423,310	418,242	397,777	410,527	411,841	444,445 MW.h
Unit #2 at 4.380 GW.h - no Unit #1 generation in 2012 and 2013. 2014-2016 based on long-term average at 8.730 GW.h. 2017 is based on YEC 2017/18 GRA forecast.							
L13a	YEC Grid Load amount per Column A of Approved DCF Term Sheet Table	420,000	415,000	395,000	410,000	410,000	440,000 GW.h
L13b	Expected Base Thermal Generation at YEC Grid Load amount in row L13a	14,100	11,800	4,400	9,800	9,800	24,228 MW.h
L14a	Incremental Expected Thermal Generation as percent of load above L13a (%)	46%	46%	32%	40%	40%	58% %
Table 1.1, Approved DCF Term Sheet (Order 2015-06). 2017 is based on proposal included in YEC's 2017/18 GRA, Appendix 3.4, Table 3.4-1.							
L14b=(L12-L13a)xL14a	Expected Incremental Thermal Generation above amount in L13b	1,522	1,491	889	211	736	2,578 MW.h
L15=L13b+L14b	Total Expected YEC Thermal Generation	15,622	13,291	5,289	10,011	10,536	26,806 MW.h
Derived from Table 1.1, Approved DCF Term Sheet (Order 2015-06). 2017 is based on proposal included in YEC's 2017/18 GRA, Appendix 3.4, Table 3.4-1.							
L16=L15	Expected YEC Thermal Generation in Rates	15,622	13,291	5,289	10,011	10,536	26,806 MW.h
	Diesel	15,622	13,291	5,289	8,509	-	3,623 MW.h
	LNG				1,502	10,536	23,184 MW.h
100% of long-term average Expected thermal less expected LNG. At 15% LNG displacement of expected diesel in 2015; 100% of expected thermal in 2016; 90% of expected thermal in 2017, subject to not exceeding expected thermal less actual diesel.							
L17=L7b	YEC Thermal Generation	2,683	1,037	615	2,822	5,087	13,261 MW.h
	Diesel	2,683	1,037	615	2,229	2,293	3,623 MW.h
	LNG				593	2,794	9,638 MW.h
Net of capital, RFIS and (for 2017) maintenance thermal (L7b)							
L18=L17-L16	YEC Thermal Generation to be Included in DCF	-	12,939 -	4,674 -	7,189 -	5,449 -	13,545 MW.h
	Diesel	-	12,939 -	4,674 -	6,281 -	-	- MW.h
	LNG			-	909 -	5,449 -	13,545 MW.h
L19=L1xL18	Incremental YEC Thermal Generation Cost to Charge (Refund) DCF (\$000s)	(\$3,715)	(\$3,518)	(\$1,342)	(\$1,974)	(\$990)	(\$1,987)

2
3

1

Table 2: DCF Continuity Schedule

Line	Activity	2012 (\$000s)	2013 (\$000s)	2014 (\$000s)	2015 (\$000s)	2016 (\$000s)	2017 Preliminary (\$000s)
A	DCF Opening Balance¹	\$902	\$4,628	\$8,198	\$9,627	\$10,895	\$9,485
B	Incremental Diesel Generation Cost to Charge/(Refund)² to DCF	(\$3,715)	(\$3,518)	(\$1,342)	(\$1,974)	(\$990)	(\$1,987)
C=B	Total DCF operation for YEC	\$3,715	\$3,518	\$1,342	\$1,974	\$990	\$1,987
	YEC pays to DCF Fund	\$0	\$0	\$0	\$0	\$0	\$0
	YEC withdraws from DCF Fund						
D=A+C	DCF Balance after Total DCF Operation	\$4,617	\$8,146	\$9,540	\$11,601	\$11,885	\$11,472
E	Interest on DCF Balance³	\$11	\$52	\$87	\$53	\$54	\$86
F=D+E	DCF Balance after Interest charge	\$4,628	\$8,198	\$9,627	\$11,654	\$11,939	\$11,557
G	DCF (Rebate)/Collections [January - December]	\$0	\$0	\$0	(\$759)	(\$2,454)	(\$2,861)
H=F+G	DCF Ending Balance	\$4,628	\$8,198	\$9,627	\$10,895	\$9,485	\$8,697
I	DCF (Rebate)/Collections January - April 30, 2018 (forecast)						(\$1,064)
J=H+I	Forecast DCF Balance, After (Rebate)/Collections to April 30						\$7,633
K	DCF Cap Approved by Board⁴						+/-8000
L=J-K	DCF Rebate/(Collections) Required						\$0

Notes:

1. 2012 DCF Opening Balance is 2011 actual ending balance of DCF.

2. Based on calculations in Table 1. 2016 and 2017 DCF charge estimate is based on preliminary actuals.

3. Per the March 11, 1996 letter recording the settlements [provided as Exhibit B-16 in the 2008/2009 GRA] the DCF fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.

4. Approved DCF Cap based on YUB Order 2015-01.

2

3

1

Table 3: Rider E Calculations

Line	Activity	Rider Estimate
A	DCF Rebate/(Collections) Required (\$000s)	\$0
B	Retail Sales for the previous 12 months (MW.h)	
C=A/B	DCF Rebate/(Collection) Rider (cents/kW.h)	

Notes:

1. No Rider E calculation is required as the balance is expected to be within +/- \$8 million threshold approved by the YUB.

2

3

1

Table 4: DCF Quarterly Report (2017 Q4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Preliminary Actual	Preliminary Actual	Preliminary Actual	
Generation Report													
L1	49,560	41,098	42,318	34,749	34,316	29,360	29,843	30,733	29,195	38,906	47,369	48,108	455,554
L2	-384	-977	-52	-1,003	-1,059	-814	-1,213	-836	-803	-591	-886	-478	-9,097
L3	931	786	862	649	725	590	576	167	87	625	557	547	7,103
L4=Sum(L1:L3)	50,107	40,907	43,129	34,395	33,982	29,137	29,206	30,064	28,479	38,939	47,040	48,176	453,561
Actual Generation Sources													
L5	931	786	862	649	725	590	576	167	87	625	557	547	7,103
L6	46,475	38,327	39,807	33,726	33,114	28,390	28,499	29,674	27,731	38,254	45,023	42,932	431,951
L7	880	549	981	21	110	156	131	187	84	28	441	1,050	4,618
L7a	491	9	4	14	108	103	129	1	26	27	16	67	995
L7b=L7-L7a	389	540	977	7	2	53	2	186	58	1	425	983	3,623
L8	1,821	1,245	1,478	-	-	-	-	37	577	33	1,019	3,647	9,856
L8a	159	1	-	-	-	-	-	15	-	-	-	43	218
L8b=L8-L8a	1,662	1,243	1,478	-	-	-	-	37	562	33	1,019	3,605	9,638
L9	-	-	-	-	33	-	-	-	-	-	-	-	33
L10=L5+L6+L7+L8+L9	50,107	40,907	43,129	34,395	33,982	29,137	29,206	30,064	28,479	38,939	47,040	48,176	453,561
Expected Generation Sources													
L11													8,536
L12													580
L13=L10-L11-L12													444,445
L14													440,000
L15													58%
L16													24,228
L17=(L13-L14)xL15													2,578
L18=L16+L17													26,806
L19=L18													26,806
													-
													26,806
L20=L7b+L8b													13,261
													3,623
													9,638
L21=L20-L19													(13,545)
													-
													13,545
L22													0.2633
													0.1467
													(\$1,987)
L23=L21xL22													
L24													9,485
L25													(3,925)
L26													86
L27=L24+L25+L26-L23													7,633

2

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission,**
4 **page 4.2.4**

5
6 *Figure 4.2A-2 - Residential Electricity Bill in Comparison to Yukon*

7
8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) Please explain how Figure 4.2A-2 is useful to the YUB in deliberating the request
13 made in the current GRA application.
14
15 b) Please provide details of the generation mix for each of the locations identified on
16 this chart.
17
18 c) Please provide an updated Figure 4.2A-2 which includes all applicable rate relief
19 and taxes for each of the locations identified on this chart.
20

21 **ANSWER:**

22
23 **(a)**

24
25 Figure 4.2A-2 provides background information comparing Yukon residential electricity
26 bills (existing and proposed), before rate relief and taxes, with residential bills in various
27 cities throughout northern and southern Canada. It is background information for the
28 Board and all parties.
29

30 **(b) and (c)**

31
32 The information requested regarding generation mix and/or applicable rate relief and taxes
33 was not part of the reference material used to generate Figure 4.2A-2. Assembling the
34 information requested will require additional extensive research and consultation with
35 utilities in other jurisdictions and cannot be completed in the timeframes outlined in this
36 proceeding.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission**

4
5 *Tab 5 – Capital Projects*

6
7 **PREAMBLE:**

8
9 **QUESTION:**

- 10
11 a) Please provide updates to Tables 5.1 through 5.8 showing 2017 actuals and any
12 updated 2018 forecast.

13
14 **ANSWER:**

15
16 **(a)**

17
18 Final actual results for 2017 are not available and as such requested updates to GRA
19 application tables included in Tab 3, Tab 5 and Tab 7 cannot be provided at this time.
20 There are no updates to the 2018 forecast in Tab 2, Tab 3, Tab 5 and Tab 7 as included
21 in Yukon Energy's June 2017 General Rate Application filing.

22
23 Please also see response to UCG-YEC-2-42.

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission**

4
5 *Tab 7 – Financial Schedules*

6
7 **PREAMBLE:**

8
9 **QUESTION:**

- 10
11 a) Please provide updates to all schedules in Tab 7 showing 2017 actuals and any
12 updated 2018 forecast.

13
14 **ANSWER:**

15
16 **(a)**

17
18 Final actual results for 2017 are not available and as such requested updates to GRA
19 application tables included in in Tab 2, Tab 3, Tab 5 and Tab 7 cannot be provided at this
20 time. YEC also notes that its GRA filing from June 2017 with LTA hydro forecasts, rather
21 than the Alternative GRA Forecast Submission with ST hydro forecasts, is what is being
22 applied for by Yukon Energy in this proceeding.

23
24 Pursuant to section 25(1) of the *Public Utilities Act*, Yukon Energy is required to file an
25 annual financial filing for 2017 by March 31. This is provided as Attachment 1 to this
26 response. The section 25(1) filing includes unaudited financial statements for the year
27 ended December 31, 2017 and related 2017 information required by Section 25 of the
28 *Public Utilities Act* including the following:

- 29
30 1. Unaudited 2017 Financial Statements
31 2. Regulatory Schedules prepared based on unaudited 2017 financial results:
32 a. Statement of utility income and rate of return;
33 b. Computation of net rate base;
34 c. Working capital calculation;
35 d. Reconciliation of utility income to net earnings;
36 e. Summary of capital assets;
37 f. Cost of capital calculation;

1 3. List of Directors and Officers as at December 31, 2017

2

3 The Audited Financial Statements and final Regulatory Schedules will not be available
4 until after the year-end audit is complete and the statements are approved by the Board
5 of Directors.

6

7 There are no updates to the 2018 forecast as included in Yukon Energy's June 2017
8 General Rate Application filing.



Yukon Energy Corporation
Box 5920
Whitehorse, Yukon Y1A 6S7

March 29, 2018

Mr. Robert Laking, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. Laking:

Re: 2017 Annual Filings – Yukon Energy Corporation – Section 25

Please find enclosed the unaudited financial statements for the year ended December 31, 2017 along with related 2017 information required by Section 25 of the *Public Utilities Act* including:

1. Unaudited 2017 Financial Statements
2. Regulatory Schedules prepared based on unaudited 2017 financial results:
 - a. Statement of utility income and rate of return
 - b. Computation of net rate base
 - c. Working capital calculation
 - d. Reconciliation of utility income to net earnings
 - e. Summary of capital assets
 - f. Cost of capital calculation
3. List of Directors and Officers as at March 29, 2018

Please be advised that the Audited Financial Statements and final Regulatory Schedules will be submitted after the year-end audit is complete and the statements are approved by the Board of Directors.

Yours truly,

A handwritten signature in black ink, appearing to read 'Ed Mollard'.

Ed Mollard, CPA CGA
Chief Financial Officer
Yukon Energy Corporation

April 6, 2018

A-1

Yukon Energy Corporation
Financial Statements
December 31, 2017

DRAFT

Yukon Energy Corporation

Financial Statements

December 31, 2017

Page

Management's Responsibility for Financial Reporting	2
Independent Auditor's Report	3-4
Statement of Financial Position	5
Statement of Operations and Other Comprehensive Income	6
Statement of Changes in Equity	7
Statement of Cash Flows	8
Notes to Financial Statements	9-42

Yukon Energy Corporation
Statement of Financial Position
(in thousands of Canadian dollars)

As at	December 31 2017	December 31 2016
Assets		
Current		
Cash	\$ -	\$ 551
Accounts receivable (Note 5)	12,427	5,873
Inventories (Note 6)	3,782	3,597
Prepaid expenses	678	754
	16,887	10,775
Non-current		
Property, plant and equipment (Note 7)	448,444	444,354
Intangible assets (Note 8)	8,476	7,281
Total assets	473,807	462,410
Regulatory deferral account debit balances (Note 9)	25,738	27,880
Total assets and regulatory deferral account debit balances	\$ 499,545	\$ 490,290
Liabilities		
Current		
Bank indebtedness (Note 10)	\$ 7,054	\$ -
Accounts payable and accrued liabilities (Note 11)	10,845	8,535
Construction financing (Note 12)	22,385	22,385
Derivative related liability (Note 24)	56	409
Current portion of long-term debt (Note 13)	5,248	5,238
	45,588	36,567
Non-current		
Post-employment benefits (Note 14)	6,116	5,867
Contributions in aid of construction (Note 15)	168,988	172,770
Decommissioning fund (Note 16)	2,665	2,636
Long-term debt (Note 13)	142,523	147,771
Total liabilities	365,880	365,611
Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued and fully paid: 3,900 shares	39,000	39,000
Contributed surplus	14,600	14,600
Retained earnings	61,075	51,034
Total equity	114,675	104,634
Total liabilities and equity	480,555	470,245
Regulatory deferral account credit balances (Note 9)	18,990	20,045
Total liabilities, equity and regulatory deferral account credit balances	\$ 499,545	\$ 490,290

Commitments and Contingencies (Notes 20 and 21)

The accompanying notes are an integral part of these financial statements.

Approved by the Board

_____, Chair

_____, Director

Yukon Energy Corporation
Statement of Operations and Other Comprehensive Income
(in thousands of Canadian dollars)

For the year ended December 31	2017	2016
Revenues		
Sales of power (Note 17)	\$ 48,789	\$ 40,013
Funding from parent (Note 20)	565	825
Other	369	287
	49,723	\$ 41,125
Operating expenses		
Operations and maintenance (Note 18)	18,212	19,322
Administration (Note 19)	10,712	11,923
Depreciation and amortization (Notes 7 and 8)	12,662	11,262
	41,586	42,507
(Loss) Income from operations	8,137	(1,382)
Other income		
Allowance for funds used during construction	466	819
Amortization of contributions in aid of construction (Note 15)	4,116	4,102
Unrealized gain on interest rate swap (Note 24)	353	144
	4,935	5,065
Other expenses		
Interest on borrowings	4,303	3,536
	4,303	3,536
Net income for the year before net movements in regulatory deferral account balances	8,769	147
Net movement in regulatory deferral account balances related to net income (Note 9 (d))	1,520	7,908
Net income for the year and net movements in regulatory deferral account balances	10,289	8,055
Other Comprehensive Income (Note 3 (o))		
Item that will not be reclassified to net income in subsequent periods		
Re-measurement of defined benefit pension plans (Note 14)	(248)	(483)
Total comprehensive income for the year	\$ 10,041	\$ 7,572

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Changes in Equity
(in thousands of Canadian dollars)

	Share Capital Number of shares	\$	Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at December 31, 2015	3,900	\$ 39,000	\$ 14,600	\$ 46,303	-	\$ 99,903
Net income for the year and net movement in regulatory deferral account balances	-	-	-	8,055	-	8,055
Other comprehensive income	-	-	-	-	(483)	(483)
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	(483)	483	-
Dividends	-	-	-	(2,841)	-	(2,841)
Balance at December 31, 2016	3,900	\$ 39,000	\$ 14,600	\$ 51,034	-	\$ 104,634
Net income for the year and net movement in regulatory deferral account balances	-	-	-	10,289	-	10,289
Other comprehensive income	-	-	-	-	(248)	(248)
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	(248)	248	-
Balance at December 31, 2017	3,900	\$ 39,000	\$ 14,600	\$ 61,075	-	\$ 114,675

The accompanying notes are an integral part of these financial statements.

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Yukon Energy Corporation
Statement of Cash Flows
(in thousands of Canadian dollars)

For the year ended December 31	2017	2016
Operating activities		
Cash receipts from customers	\$ 43,159	\$ 40,814
Cash receipts from parent	-	825
Cash receipts from contributions in aid of construction	332	332
Cash paid to suppliers	(17,368)	(17,464)
Cash paid to employees	(11,539)	(11,640)
Interest paid	(3,668)	(3,473)
Cash provided by operating activities	10,916	9,394
Financing activities		
Receipt of construction financing	-	8,400
Repayment of long-term debt	(5,238)	(6,067)
Cash provided by financing activities	(5,238)	2,333
Investing activities		
Additions to property, plant and equipment	(10,618)	(11,530)
Additions to intangible assets	(2,665)	(1,318)
Cash used in investment activities	(13,283)	(12,848)
Net (decrease) increase in cash	(7,605)	(1,121)
Cash, beginning of year	551	1,672
Cash, end of year	\$ (7,054)	\$ 551

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

1. NATURE OF OPERATIONS

a) General

Yukon Energy Corporation ("the Utility") is incorporated under the Yukon *Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation ("YDC" or "the Parent"), a corporation owned by the Yukon Government ("YG" or "the Government"). The Utility generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes. The Utility's principal place of business is located at #2 Miles Canyon Road, Whitehorse, Yukon, Y1A 6S7.

The Utility is subject to overall regulation by the Yukon Utilities Board (YUB) and specific regulation by the Yukon Water Board. Both boards are consolidated by the Government and as such are considered to be related parties for accounting purposes. Management has assessed that these boards operate independently from the Utility from a rate setting and operating perspective.

b) Rate regulation

The operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility files a General Rate Application (GRA) for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principles of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the YG through Orders-In-Council ("OIC") that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility expects it will incur to provide electricity to its customers over the immediate future are reviewed and approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the depreciation of all capital equipment; and
- the return on rate base (the borrowing costs related to borrowing that portion of rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of rate base which is financed with equity).

The YUB assesses the prudence of costs added to rate base, which includes an allowance for funds used during construction ("AFUDC") charged to capital projects. The YUB also reviews the appropriateness of property, plant and equipment depreciation rates, which are periodically updated by the Utility through depreciation studies.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: residential, government, commercial and industrial. This process is guided mainly by requirements of OIC 1995/90 and can include a cost-of-service study which allocates the Utility's overall cost of service to the various customer classes on the basis of appropriate costing principles.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

1. NATURE OF OPERATIONS - continued

c) Water regulation

The Yukon Water Board, pursuant to the *Yukon Waters Act*, decides if and for how long the Utility will have a water license for the purposes of operating hydro generation stations in the Yukon. The licenses will also indicate terms and conditions for the operation of these facilities.

d) Capital structure

The Utility's policy which has been approved by the YUB is to maintain a capital structure of 60% debt and 40% equity (Note 24). Dividends are normally declared annually to the Parent and are typically loaned back in order to maintain this ratio during normal on-going operations. When large assets are purchased or constructed, the Parent may be required to make an equity or capital contribution.

2. BASIS OF PRESENTATION

a) Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

These financial statements were authorized for issue by the Board of Directors on May 9, 2018.

b) Basis of measurement

The financial information included in the financial statements has been prepared on a historical cost basis, except for financial instruments which are measured at fair value.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied to all periods presented in these financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

3. SIGNIFICANT ACCOUNTING POLICIES - continued

a) Revenue recognition

All revenues are recognized in the period earned. Revenue from the sale of power is recognized based on cyclical meter readings. Sales of power includes an accrual for electricity deliveries not yet billed at year-end.

b) Translation of foreign currencies

The functional currency of the Utility is the Canadian Dollar. Revenue and expense items denominated in foreign currencies are translated at exchange rates prevailing during the period. Monetary assets and liabilities denominated in foreign currencies are translated at period-end exchange rates. Non-monetary assets and liabilities are translated at exchange rates in effect when the assets are acquired or the obligations are incurred. Foreign exchange gains and losses are reflected in net income for the period.

c) Allowance for funds used during construction

The cost of the Utility's property, plant and equipment and deferred charges includes an allowance for funds used during construction (AFUDC) as allowed by the regulator. The AFUDC rate is based on the Utility's weighted average cost of debt.

d) Cash

Cash is comprised of bank account balances (net of outstanding cheques).

e) Inventories

Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. Inventories are carried at the lesser of weighted average cost and net realizable value. Cost includes all expenditures incurred in acquiring the items and bringing them to their existing condition and location. Critical spare parts are recognized in the Utility's property, plant and equipment.

The recoverable value of inventory considers its net realizable value, including required processing costs, and is impacted by estimates and assumptions on prices, quality, recovery and exchange rates. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

f) Financial instruments

Financial assets and financial liabilities are recognized on the Utility's Statement of Financial Position when the Utility becomes party to the contractual provisions of the instrument. Accounts receivable, classified as loans and receivables, are initially measured at fair value. Subsequent to initial recognition, accounts receivable are measured at amortized cost using the effective interest rate method less any impairment.

A provision for impairment of accounts receivable is established when there is objective evidence that the Utility will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulties of the debtor, probability that the debtor will enter into bankruptcy or require financial reorganization, and default or delinquency in payments are considered indicators that the related accounts receivable are impaired. The accounts receivable carrying amount is reduced through the use of an allowance account and the loss is recognized in net income.

Cash, accounts payable and accrued liabilities, construction financing and long-term debt are classified as other financial liabilities and they are initially recognized at fair value. Subsequent to initial recognition, they are measured at amortized cost using the effective interest rate method (except for cash which is measured at cost).

Transaction costs are presented as a reduction from the carrying value of the related debt and are amortized using the effective interest rate method over the terms of the debts to which they relate. Transaction costs include fees paid to agents, brokers and advisors but exclude debt discounts and lender financing costs.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

3. SIGNIFICANT ACCOUNTING POLICIES - continued

f) Financial instruments - continued

Derivative financial instruments are financial contracts that derive their value from changes in an underlying variable. The Utility has entered into an interest rate swap to manage interest rate risk. The Utility's interest rate swap is classified as held for trading and is thus recognized at fair value on the date the contract has been entered into with any subsequent realized and unrealized gains and losses recognized in net income during the period in which the fair value movement occurred.

g) Property, plant and equipment

Property, plant and equipment are carried at cost, less accumulated depreciation and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs, AFUDC and any asset retirement costs associated with the property, plant and equipment.

AFUDC is based on the Utility's weighted average cost of borrowing and is applied to actual costs in work-in-progress less any contributions in aid of construction. For items of property, plant and equipment acquired prior to January 1, 2011, the AFUDC rate also included a regulatory cost of equity component as allowed by the YUB. Capitalization of AFUDC ceases when the asset being constructed is substantially ready for its intended purpose.

Assets under construction are recognized as in construction work in progress until they are operational and available for use, at which time they are transferred to the applicable component of property, plant and equipment.

Depreciation is recognized in net income based on the straight-line method over the estimated useful life of each major component of property, plant and equipment. The range of the estimated useful lives of the major classes and subclasses of property, plant and equipment is as follows:

Generation	
Hydroelectric plants	30 to 103 years
Thermal plants	12 to 72 years
Wind turbines	30 years
Transmission	20 to 65 years
Distribution	12 to 55 years
Buildings	20 to 55 years
Transportation	9 to 31 years
Other equipment	5 to 20 years

Depreciation commences when an asset is available for use. The estimated useful lives of the assets are based upon depreciation studies conducted periodically by the Utility and any changes in the estimated useful lives are accounted for prospectively.

Gains and losses on the disposal or retirement of property, plant and equipment, with the exception of land and vehicles, are deferred and amortized over the remaining expected useful life of the related assets under regulatory accounting (Note 9). These gains and losses are recognized immediately in net income under IFRS.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

3. SIGNIFICANT ACCOUNTING POLICIES - continued

g) Property, plant and equipment - continued

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period of the expected useful life (until the next major overhaul) which varies from 5 to 10 years. However, major overhaul costs cannot be depreciated for regulatory purposes until the costs are approved by the YUB (Note 9). Repairs and maintenance costs of property plant and equipment are expensed as incurred unless they meet the criteria of a betterment.

h) Intangible assets

Intangible assets are carried at cost less accumulated amortization and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs and AFUDC.

Amortization is recognized in net income on a straight-line basis over the estimated useful lives as follows:

Software	5 years
Deferred customer service costs	12 years
Financial software	10 years
Licencing costs	
Hydro generation	17 to 25 years
Diesel generation	3 years

i) Impairment of non-financial and financial assets

Property, plant and equipment, regulatory deferral debit balances and intangible assets with finite lives are reviewed for impairment on an annual basis if there is an indication that the carrying amount may not be recoverable. Impairment is assessed at the level of cash-generating units, which are identified as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or group of assets.

When an impairment review is undertaken, the recoverable amount is assessed by reference to the higher of value in use and fair value less costs to sell ("FVLCS") for non-financial assets and objective evidence of impairment in the case of financial assets. Value in use is the net present value of expected future cash flows of the relevant cash-generating unit in its current condition. The best evidence of FVLCS is the value obtained from an active market or binding sale agreement. Where neither exists, FVLCS is based on the best information available to reflect the amount the Utility could receive for the cash generating unit in an arm's length transaction. This is often estimated using discounted cash flow techniques and where unobservable inputs are material to the measurement of the recoverable amount, the measurement is classified as level 3 in the fair value hierarchy. The cash flow forecasts for FVLCS purposes are based on management's best estimates of expected future revenues and costs, including the future cash costs of production, capital expenditure, closure, restoration and environmental cleanup. For regulatory deferral debit balances the impairment review focuses on whether the amount is considered collectible based on the expected cash flows from the rates approved by the YUB.

These determinations and their individual assumptions require that management make a decision based on the best available information at each reporting period. Changes in these assumptions may alter the results of non-financial asset and financial asset impairment testing, impairment charges recognized in net income and the resulting carrying amounts of the assets.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

3. SIGNIFICANT ACCOUNTING POLICIES - continued

j) Rate regulated accounting policies

Regulatory deferral accounts

Regulatory deferral accounts in these financial statements are accounted for differently than they would be in the absence of rate regulation. Where regulatory decisions dictate, the Utility defers certain costs or revenues as regulatory deferral account debit balances or regulatory deferral account credit balances on the Statement of Financial Position and recognizes them in the net movement in regulatory deferral account balances in the Statement of Operations and Other Comprehensive Income as it collects or refunds amounts through future customer rates. Any adjustments to these regulatory deferral accounts are recognized in the net movement in regulatory deferral account balances in the period that the YUB renders a subsequent decision. All amounts maintained as regulatory deferral account debit balances and regulatory deferral account credit balances are expected to be recovered or settled and are assessed on a yearly basis by comparing the rates approved by the YUB to the current balances. The recovery or settlement of regulatory deferral account balances through future rates is impacted by demand risk and regulatory risks (e.g. potential future decisions of the YUB which could result in material adjustments to these regulatory deferral account debit balances and regulatory deferral account credit balances as described in Note 1(b)).

i) Regulatory deferral account debit balances

Regulatory deferral account debit balances represent incurred costs which have been deferred and are recognized or being amortized over various periods as approved by the YUB. Regulatory deferral account debit balances represent costs which are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such costs would be expensed as incurred.

ii) Regulatory deferral account credit balances

Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such amounts would be recorded in income as earned.

Note 9 describes the individual regulatory deferral accounts, the Utility's related regulatory deferral and amortization policies and describes the related account activity in the relevant periods.

k) Provision for asset retirement obligations

The Utility has legal obligations related to the closure and restoration of property, plant and equipment, which includes the costs of dismantling, demolition of infrastructure and the removal of residual materials and remediation of the disturbed areas.

Where a reliable estimate of the present value of these obligations can be determined, the total retirement costs are recognized as a provision in the accounting period when the obligation arises. There is also a corresponding increase to property, plant and equipment upon recognition of the obligation. Management estimates its costs based on feasibility and engineering studies and assessments using current restoration standards and techniques.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

3. SIGNIFICANT ACCOUNTING POLICIES - continued

l) Provision for environmental liabilities

Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a provision when it has a present obligation as a result of a past event to remediate the contaminated site, it is expected that future economic benefits will be given up to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

If the likelihood of the Utility's obligation to incur these costs is either not determinable or the amount of the obligation cannot be reliably estimated, the contingency is disclosed in the notes to the financial statements.

The Utility reviews its provision for environmental liabilities on an ongoing basis and any changes are recognized in net income for the current period.

m) Contributions in aid of construction

Certain property, plant and equipment additions are made with the assistance of cash contributions from customers or capital assistance from the Utility's Parent, the YG, or the Government of Canada. These contributions are deferred upon receipt and amortized to income on the same basis as the assets to which they relate.

n) Decommissioning fund

The decommissioning fund represents monies paid in advance by an industrial customer to decommission the spur line that connects its operation to the Utility's grid. Under a power purchase agreement, the customer has the financial responsibility for decommissioning expenses to be performed by the Utility on its behalf. Any amounts not required for decommissioning will be refunded to the customer. This money accrues interest at the rate equal to the three month Canadian Dealer Offered Rate ("CDOR").

o) Post-employment benefits and other comprehensive income

The Utility sponsors an employee defined benefit pension plan which provides benefits based on the length of service and average salaries for the five highest paid consecutive years of service. Effective January 1, 2011, the Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

For the defined benefit plan the cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Re-measurements of the net defined benefit liability, including actuarial gains and losses and return on plan assets, are recognized in other comprehensive income ("OCI") and are not reclassified to net income in a subsequent period. The Utility's policy is to immediately transfer actuarial gains and losses recognized in OCI to retained earnings. The expected return on plan assets is based on the fair value of these assets.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

3. SIGNIFICANT ACCOUNTING POLICIES - continued

o) Post-employment benefits and other comprehensive income - continued

Employees joining the Utility after January 1, 2002 are eligible for a defined contribution retirement plan and are not eligible to participate in the defined benefit pension plan. Contributions are required by both employees and the Utility to cover the current service cost of this defined contribution retirement plan. The Utility has no legal or constructive obligation to pay further contributions with respect to this plan. Consequently, contributions are recognized as an expense in the year when employees have rendered service and represents the obligation of the Utility.

p) New standards and interpretations not yet adopted

A number of new standards, and amendments to standards and interpretations, are not yet effective for the period ended December 31, 2017, and have not been applied in preparing these financial statements. There are three standards that management has identified as having a potential impact and is in the process of assessing, IFRS 15, *Revenue from Contracts with Customers*, IFRS 9, *Financial Instruments* which will replace IAS 39, *Financial Instruments* and IFRS 16, *Leases*.

i) On May 28, 2014, the IASB issued IFRS 15, *Revenue from Contracts with Customers*, which will replace IAS 18, *Revenue*. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard contains a single model that applies to contracts with customers and two approaches to recognising revenue: at a point in time or over time. The model features a contract based five step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Utility intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The Utility has completed the preliminary analysis and there are no significant changes to its financial statements.

ii) IFRS 9, *Financial Instruments*, which will replace IAS 39, *Financial Instruments: Recognition and Measurement* and IFRIC 9, *Reassessment of Embedded Derivatives*. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard is expected to impact the classification and measurement of financial assets, introduce changes to financial liabilities and includes new hedge accounting requirements. The Utility intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Utility has completed the analysis of this standard and there are no significant changes to its financial statements.

iii) IFRS 16, *Leases*, specifies how to recognize, measure, present and disclose leases. The standard provides a single lessee model, requiring lessees to recognize assets and liabilities for all leases unless the lease term is 12 months or less or the underlying asset has a low value. Lessors continue to classify leases as operating or finance, with IFRS 16's approach to lessor accounting substantially unchanged from its predecessor, IAS 17. This standard will become effective for annual periods beginning on or after January 1, 2019. The Utility is currently assessing the impact on its financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements requires the use of judgment in applying accounting policies and in making critical accounting estimates that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of any contingent assets and liabilities. These judgments and estimates are based on management's best knowledge of the relevant facts and circumstances, having regard to previous experience, but actual results may differ from the amounts included in the financial statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected. Information about such judgments and estimates is contained in the accounting policies and/or the notes to the financial statements, and the key areas are summarized below.

Areas of significant judgment and estimates made by management in preparing these financial statements include:

Impairment of long-lived assets - Notes 3g) and 7

An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Management continually monitors the Utility's operations and makes judgements and assessments about conditions and events in order to conclude whether possible impairment exists.

Asset retirement obligations – Notes 3k) and 22

In determining the present value of the obligation, the Utility must estimate the amount and timing of the future cash payments and then apply an appropriate risk-free interest rate. Any changes to the anticipated amounts or timing of future payments or risk-free interest rate can result in a change to the obligation.

Depreciation and amortization – Notes 3g), h), 7 and 8

Significant components of property, plant and equipment are depreciated over their estimated useful lives. Useful lives are determined based on current facts and past experience and the results of depreciation studies. While these useful life estimates are reviewed on a regular basis and depreciation calculations are revised accordingly, actual lives may differ from the estimates. As such, assets may continue in use after being fully depreciated, or may be retired or disposed of before being fully depreciated. The latter could result in additional depreciation expense in period of disposition.

Intangible assets - Notes 3h) and 8

In determining when to recognize costs as intangible assets, management makes judgments about when the criteria for recognition are met. Changes to management's judgments would affect the carrying amount of its intangible assets and amortization recognition.

Regulatory deferral account debit and credit balances - Notes 3j) and 9

The Utility accounts for its regulatory deferral accounts in accordance with IFRS 14 *Regulatory Deferral Accounts* and the decisions of the YUB. The decisions can be complex and require significant judgment in their interpretation.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS - continued

Post-employment benefits – Notes 3o) and 13

The Utility accrues for its obligations under defined benefit pension plans using actuarial valuation methods and other assumptions to estimate the projected benefit obligation and the associated expense related to the current period. The key assumptions utilized include the long-term rate of inflation, rates of future compensation, liability discount rates and the expected return on plan assets. The Utility consults with qualified actuaries when setting the assumptions used to estimate benefit obligations. Actual rates could vary significantly from the assumptions and estimates used.

Revenue – Note 16

The Utility estimates usage not yet billed at year end, which is included in revenues from sale of power. This accrual is based on an assessment of unbilled electricity supplied to customers between the date of the last meter reading and the year end. Management applies judgement to the measurement of the estimated consumption.

Provisions and Contingencies - Notes 3k), l), 21 and 22

Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*.

Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation. Key assumptions in measuring recognized provisions include the timing and amount of future payments and the discount rate applied in measuring the provision.

Where the Utility is defending certain lawsuits management must make judgements, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management will obtain the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

Financial Instruments - Notes 3f) and 23

The Utility enters into financial instrument arrangements which may require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, including whether those embedded derivatives meet the criteria to be separated from their host contract, in accordance with IAS 39, *Financial Instruments: Recognition and Measurement*. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable, and for embedded derivatives, whether the economic risks and characteristics are not closely related to the host contract and a separate instrument with the same terms would meet the definition of a derivative on a standalone basis.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

5. ACCOUNTS RECEIVABLE

	December 31 2017	December 31 2016
Wholesale energy sales	\$ 8,045	\$ 3,734
Retail energy sales	2,366	1,494
Due from related parties (Note 19)	373	112
Other	1,643	533
	\$ 12,427	\$ 5,873

At December 31, 2017, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	\$ 11,204	\$ 1,169	\$ 54	\$ 12,427
Allowance for doubtful accounts	-	-	(10)	(10)
	\$ 11,204	\$ 1,169	\$ 44	\$ 12,417

At December 31, 2016, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	\$ 5,616	\$ 232	\$ 35	\$ 5,883
Allowance for doubtful accounts	-	-	(10)	(10)
	\$ 5,616	\$ 232	\$ 25	\$ 5,873

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	December 31 2017	December 31 2016
Allowance for doubtful accounts at beginning of year	\$ (10)	\$ (10)
Amounts written off as uncollectable	-	-
Allowance for doubtful accounts at end of year	\$ (10)	\$ (10)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

6. INVENTORIES

	December 31 2017	December 31 2016
Materials and supplies	\$ 3,342	\$ 3,087
Diesel fuel	337	299
Liquefied natural gas	103	211
	\$ 3,782	\$ 3,597

7. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Generation	Transmission & Distribution	Land & Buildings	Transportation & Other	Construction Work-in Progress	Total
Cost:						
At December 31, 2015	\$ 275,192	\$ 160,494	\$ 15,852	\$ 3,481	\$ 7,507	\$ 462,526
Additions	680	-	138	784	10,667	12,269
Transfers	3,100	2,834	882	-	(6,816)	-
Disposals	-	-	(635)	(311)	-	(946)
At December 31, 2016	\$ 278,972	\$ 163,328	\$ 16,237	\$ 3,954	\$ 11,358	\$ 473,849
Additions	-	-	-	553	15,434	15,987
Transfers	8,043	2,604	11,651	-	(22,298)	-
Disposals	-	-	(189)	(238)	-	(427)
At December 31, 2017	\$ 287,015	\$ 165,932	\$ 27,699	\$ 4,269	\$ 4,494	\$ 489,409
Accumulated depreciation:						
At December 31, 2015	\$ 9,014	\$ 8,210	\$ 1,588	\$ 520	\$ -	\$ 19,332
Depreciation	5,525	4,386	847	285	-	11,043
Disposals	-	-	(635)	(245)	-	(880)
At December 31, 2016	\$ 14,539	\$ 12,596	\$ 1,800	\$ 560	\$ -	\$ 29,495
Depreciation	5,798	4,413	1,329	357	-	11,897
Disposals	-	-	(189)	(238)	-	(427)
At December 31, 2017	20,337	17,009	2,940	679	-	40,965
Net book value:						
At December 31, 2016	\$ 264,433	\$ 150,732	\$ 14,437	\$ 3,394	\$ 11,358	\$ 444,354
At December 31, 2017	\$ 266,678	\$ 148,923	\$ 24,759	\$ 3,590	\$ 4,494	\$ 448,444

* Included in generation depreciation is the annual depreciation for overhauls of \$802,000 (2015 - \$778,000) which is recognized in regulatory account expenses in Note 17.

The AFUDC capitalized for 2017 was \$466,000 (2016 - \$819,000). The AFUDC rate estimate was 2.36% for 2017 (2016 - 2.40%).

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

8. INTANGIBLE ASSETS

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Software	Deferred Customer Service Costs	Financial Software	Aishihik Water Licensing	Thermal and Water Licensing	Total
Cost:						
At December 31, 2015	\$ 462	\$ 443	\$ 2,406	3,032	\$ 2,516	\$ 8,859
Additions	66	-	-	955	297	1,318
Disposals	(8)	-	-	-	-	(8)
At December 31, 2016	520	443	2,406	3,987	2,813	10,169
Additions	170	-	-	1,969	109	2,248
Disposals	-	-	-	(12)	(97)	(109)
At December 31, 2017	\$ 690	\$ 443	\$ 2,406	\$ 5,944	\$ 2,825	\$ 12,308
Accumulated amortization:						
At December 31, 2015	\$ 61	\$ 128	\$ 568	\$ 1,038	\$ 72	\$ 1,867
Amortization	92	64	283	524	58	1,021
At December 31, 2016	153	192	851	1,562	130	2,888
Amortization	124	64	283	518	64	1,053
Disposals	-	-	-	(12)	(97)	(109)
At December 31, 2017	\$ 277	\$ 256	\$ 1,134	\$ 2,068	\$ 97	\$ 3,832
Net book value:						
At December 31, 2016	\$ 367	\$ 251	\$ 1,555	\$ 2,425	\$ 2,683	\$ 7,281
At December 31, 2017	\$ 413	\$ 187	\$ 1,272	\$ 3,876	\$ 2,728	\$ 8,476

The internally generated costs and externally purchased costs for Software and Financial Software are approximately 50% internal and 50% external at December 31, 2017 and December 31, 2016. All other categories are almost exclusively internally generated.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

9. REGULATORY ACCOUNTS

Regulatory deferral account debit balances

	Feasibility Studies (i)	IFRS Planning (ii)	Regulatory Costs (iii)	Vegetation Management (iv)	Dam Safety (v)	Uninsured Losses (vi)	Subtotal See next page
Cost:							
At December 31, 2015	\$ 18,555	\$ 566	\$ 4,360	\$ 1,644	\$ 144	\$ 267	\$ 25,536
Costs incurred	4,869	-	695	1,074	4	1,018	7,660
Regulatory provision	-	-	-	(502)	-	(226)	(728)
Disposals	(2,051)	(566)	(794)	-	-	-	(3,411)
Contributions received	(825)	-	(1)	-	-	-	(826)
At December 31, 2016	20,548	-	4,260	2,216	148	1,059	28,231
Costs incurred	2,115	-	912	-	-	667	3,694
Regulatory provision	-	-	-	-	-	(479)	(479)
Disposals	(243)	-	(643)	-	-	-	(886)
Contributions received	(565)	-	(100)	-	-	-	(665)
At December 31, 2017	\$ 21,855	-	\$ 4,429	\$ 2,216	\$ 148	\$ 1,247	\$ 29,895
Accumulated amortization:							
At December 31, 2015	\$ 4,344	\$ 453	\$ 1,345	-	-	-	\$ 6,142
Amortization	25	113	248	-	-	-	386
Disposals	(2,051)	(566)	(794)	-	-	-	(3,411)
At December 31, 2016	2,318	-	799	-	-	-	3,117
Amortization	1,443	-	440	222	30	-	2,135
Disposals	(404)	-	(643)	-	-	-	(1,047)
At December 31, 2017	\$ 3,357	-	\$ 596	\$ 222	\$ 30	-	\$ 4,205
Net book value:							
At December 31, 2016	\$ 18,230	-	\$ 3,461	\$ 2,216	\$ 148	\$ 1,059	\$ 25,114
At December 31, 2017	\$ 18,498	-	\$ 3,833	\$ 1,994	\$ 118	\$ 1,247	\$ 25,690
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2016	\$ 4,019	\$ (113)	\$ 446	\$ 572	\$ 4	\$ 792	\$ 5,720
December 31, 2017	\$ 107	-	\$ 372	\$ (222)	\$ (30)	\$ 188	\$ 415
Remaining recovery years							
At December 31, 2016	5 to 10 years	0 years	10 to 45 years	Indeterminate	4 years	Indeterminate	
At December 31, 2017	5 to 10 years	0 years	10 to 45 years	Indeterminate	3 years	Indeterminate	
Absent rate regulation, net income would increase (decrease) by:							
December 31, 2016	\$ (4,019)	\$ 113	\$ (446)	\$ (572)	\$ (4)	\$ (792)	\$ (5,720)
December 31, 2017	\$ (107)	-	\$ (372)	\$ 222	\$ 30	\$ (188)	\$ (415)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

9. REGULATORY ACCOUNTS - continued

	Carry Forward	Deferred Overhauls (vii)	Fuel Price Adjustment (viii)	Deferred Gains And losses (ix)	Total
Cost:					
At December 31, 2015	\$ 25,536	\$ 1,843	\$ 4	-	\$ 27,383
Cost incurred	7,660	925	-	-	8,585
Regulatory provision	(728)	-	-	-	(728)
Disposals	(3,411)	-	-	-	(3,411)
Contributions received	(826)	-	(6)	-	(832)
At December 31, 2016	28,231	2,768	(2)	-	30,997
Cost incurred	3,694	-	-	-	3,694
Regulatory provision	(479)	(2,768)	-	-	(3,247)
Disposals	(886)	-	-	-	(886)
Contributions received	(665)	-	50	-	(615)
At December 31, 2017	\$ 29,895	-	\$ 48	-	\$ 29,943
Accumulated amortization:					
At December 31, 2015	\$ 6,142	-	-	-	\$ 6,142
Amortization	386	-	-	-	386
Disposals	(3,411)	-	-	-	(3,411)
At December 31, 2016	3,117	-	-	-	3,117
Amortization	2,135	-	-	-	2,135
Disposals	(,047)	-	-	-	(,047)
At December 31, 2017	\$ 4,205	-	-	-	\$ 4,205
Net book value:					
At December 31, 2016	\$ 25,114	\$ 2,768	\$ (2)	-	\$ 27,880
At December 31, 2017	\$ 25,690	-	\$ 48	-	\$ 25,738
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income):					
December 31, 2016	\$ 5,720	\$ 925	\$ (6)	-	\$ 6,639
December 31, 2017	\$ 415	\$ -	\$ 50	-	\$ 465
Remaining recovery years					
At December 31, 2016		Indeterminate	1 year		
At December 31, 2017		Indeterminate	1 year		
Absent rate regulation, Net Income would increase (decrease) by:					
December 31, 2016	\$ (5,720)	\$ (925)	\$ 6	-	\$ (6,639)
December 31, 2017	\$ (415)	\$ -	\$ (50)	-	\$ (465)

(a) Regulatory deferral account debit balances

(i) Feasibility studies and infrastructure planning

The Utility undertakes certain studies to determine the feasibility of a range of projects and infrastructure proposals. While in progress, the costs of these studies are deferred within this account. Once the study is completed, the costs are amortized over a prescribed number of years ranging between five and ten years under regulatory reporting. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(ii) IFRS planning

These deferred costs are associated with the conversion from previous GAAP to IFRS and are amortized over a term of five years. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

9. REGULATORY ACCOUNTS - continued

(iii) Regulatory costs

These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings but also include resource plans, hearing costs from before 2012 and demand side management costs (consumer energy conservation program). The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(iv) Vegetation management

These deferred costs are annual brushing costs in excess of the maximum annual amount approved by the YUB. Amortization of these costs has not yet been approved. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(v) Dam safety review

The Utility has a program of conducting safety reviews of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are being amortized over five years as approved by the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(vi) Uninsured losses

The YUB has approved the use of a deferral account for uninsured damages and injuries as a means of self-insurance. The account is maintained through an annual provision approved by the YUB and collected through customer rates. Variances between the approved annual provision and actual costs incurred are deferred until the following GRA or until a specific application is made to the YUB requesting recovery from or refund to customers. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(vii) Deferred overhauls

Overhauls represent costs incurred to overhaul engines that are used in operations and these overhauls are recorded as property, plant and equipment. The Utility was directed by YUB Order 2013-01 to defer all overhaul costs incurred after 2011 until the Utility comes before the YUB for a prudence review and the costs are approved to be depreciated. IFRS requires these completed overhauls to be considered in service and they should be depreciated through net income. In addition, IFRS also requires that AFUDC would cease when the overhaul is substantially ready for its intended purpose. As a result the AFUDC capitalized on these completed overhauls of (2016 - \$119,000) and the associated depreciation on these overhauls of (2016 - \$802,000) are shown as a regulatory deferral account debit balance. In the 2017 GRA filing the Utility has asked to move all overhauls under the IFRS rules.

(viii) Fuel price adjustment

OIC 1995/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the YUB approved rates is deferred and recovered from or refunded to customers in a future period. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(ix) Deferred gains and losses

Deferred gains and losses represent amounts from disposals of property plant and equipment. There are no deferred gains or losses during any of the reporting years.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

9. REGULATORY ACCOUNTS - continued

Regulatory deferral account credit balances

	Deferred Insurance Proceeds (i)	Hearing reserve (ii)	Diesel Contingency Fund (iii)	Future removal and site Restoration (iv)	Total
Cost:					
At December 31, 2015	\$ 11,602	\$ 561	\$ 10,895	\$ 4,367	\$ 27,425
Cost incurred	-	(138)	-	(8)	(146)
Regulatory provision	-	550	-	-	550
Cash received	-	-	1,054	-	1,054
Cash refunded	-	-	(2,464)	-	(2,464)
At December 31, 2016	11,602	973	9,485	4,359	26,419
Cost incurred	-	(3)	-	(54)	(57)
Regulatory provision	-	53	-	-	53
Cash received	-	-	2,072	-	2,072
Cash refunded	-	-	(2,861)	-	(2,861)
At December 31, 2017	\$ 11,602	\$ 1,023	\$ 8,696	\$ 4,305	\$ 25,626
Accumulated amortization:					
At December 31, 2015	\$ 6,111	-	-	-	\$ 6,111
Amortization	263	-	-	-	263
Disposals	-	-	-	-	-
At December 31, 2016	6,374	-	-	-	6,374
Amortization	262	-	-	-	262
Disposals	-	-	-	-	-
At December 31, 2017	\$ 6,636	-	-	-	\$ 6,636
Net book value					
At December 31, 2016	\$ 5,228	\$ 973	\$ 9,485	\$ 4,359	\$ 20,045
At December 31, 2017	\$ 4,966	\$ 1,023	\$ 8,696	\$ 4,305	\$ 18,990
Net (increase) decrease in regulatory deferral account credit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the statement of operations and other comprehensive income):					
December 31, 2016	\$ 263	\$ (412)	\$ 1,410	\$ 8	\$ 1,269
December 31, 2017	\$ 262	\$ (50)	\$ 789	\$ 54	\$ 1,055
Remaining recovery years					
At December 31, 2016	20 years	Indeterminate	Indeterminate	Indeterminate	
At December 31, 2017	19 years	Indeterminate	Indeterminate	Indeterminate	
Absent rate regulation, net income would increase (decrease) by:					
December 31, 2016	\$ (263)	\$ 412	\$ (1,410)	\$ (8)	\$ (1,269)
December 31, 2017	\$ (262)	\$ 50	\$ (789)	\$ (54)	\$ (1,055)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

9. REGULATORY ACCOUNTS - continued

(b) Regulatory deferral account credit balances

(i) Deferred insurance proceeds

The deferred insurance proceeds represents a gain on fire insurance proceeds related to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to YUB Order 2000-3, is being amortized to income at the same rate as depreciation of the related replacement assets. In the absence of rate regulation, IFRS would have required the gain to have been fully recognized as income in the year received.

(ii) Hearing reserve

Pursuant to YUB Order 2013-01, the Utility has established a deferral account for future regulatory hearing costs. In accordance with the order the Utility recognized a provision of \$550,000 of hearing costs each year from 2012 to 2016. Actual hearing costs are applied to this regulatory deferral account. Variances between the annual provision and actual costs are deferred until the following GRA or until a specific application is made to the YUB requesting recovery or a refund to customers. In the absence of rate regulation, IFRS would require hearing costs to be expensed as incurred. At December 31, 2016, the Hearing Cost Reserve account had a balance of \$973,000. As part of Yukon Energy's 2017-2018 GRA, the Utility proposed the balance be amortized over a five year period (\$195,000 per year). In addition, the Utility proposed to decrease the annual provision from \$550,000 to \$250,000.

(iii) Diesel Contingency Fund and Energy Reconciliation Adjustment

The Diesel Contingency Fund ("DCF") was established by YUB Order 1996-6. The DCF is used to reimburse the Utility for costs associated with diesel generation required when there is a diesel cost variance due solely to water-related hydro and wind generation variances from YUB approved GRA forecasts.

The DCF attracts interest based upon short/intermediate term bond rates. Any negative balance attracts interest at the lowest short-term bond rates available to the Utility through its line of credit. The Utility is required to file quarterly reports with the YUB on the DCF's activity.

As part of the 2012/13 GRA, the Utility filed for changes to the DCF and Energy Reconciliation Adjustment ("ERA") provisions of the Wholesale Primary Rate Schedule. The YUB deferred a decision on these two issues pending further consultation with affected utilities and a separate proceeding to review the impacts of proposed changes.

In January 2014, the Utility filed an application to revise the DCF and ERA with the YUB. A decision was delivered February 6, 2015. In accordance with YUB Order 2015-01, the Utility defers recognition of the additional amounts collected from rate payers when the cost of diesel consumed in the period is less than the long-term average diesel requirements estimated for the actual annual generation load. These deferred revenues are recognized as revenue in the period when the cost of diesel fuel incurred for the period is greater than the long-term average diesel requirements and the reason for the shortfall is a shortage of water in the hydro system. The YUB has set a cap of +/- \$8 million for the DCF. If the balance falls outside of this range, the Utility is to make an application to the YUB requesting recovery or a refund to customers. In accordance with YUB Order 2015-06, the Utility is providing a refund to the customers of 0.68 cents/kWh effective September 1, 2015.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

9. REGULATORY ACCOUNTS - continued

(iii) Diesel Contingency Fund and Energy Reconciliation Adjustment - continued

In the 2012/13 GRA, the Utility applied to reactivate the ERA provision in the Wholesale Primary Rate Schedule. In YUB Order 2015-06, the YUB rejected the proposal and as a result the Utility eliminated the ERA balances in accounts receivable and accounts payable for the years ended December 31, 2015 and 2014.

In the absence of rate regulation, IFRS would require any amounts earned or incurred related to the DCF to be included in the Utility's net income in the year incurred.

(iv) Future removal and site restoration costs

The Utility maintains a regulatory provision for future removal and site restoration related to property plant and equipment, which is incremental to that required to be recognized as an asset retirement provision under IAS 37. The reserve has been established through amortization rates approved by the YUB. The amortization rates supporting the provision are based upon depreciation studies conducted periodically by the Utility. As a result of the YUB Order 2005-12, effective January 1, 2005, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of \$5,757,000. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches \$2,000,000.

Costs of dismantling capital assets, including site remediation, will be applied to this regulatory deferral account credit balance if they do not otherwise relate to an asset retirement provision. The period over which the provision will be reduced is dependent on the timing of future costs of demolishing, dismantling, tearing down, site restoration or otherwise disposing of the asset net of actual recoveries, and is therefore indeterminate. In the absence of rate regulation, IFRS would require these costs to be expensed or included in the gain or loss on disposal of the related property, plant and equipment, as applicable.

(c) Regulatory account expenses

Regulatory account expenses represent costs incurred related to regulatory account debit balances of \$3,441,000 (2016 - \$8,585,000) and regulatory account credit balances of \$58,000 (2016 - \$146,000). Total regulatory expenses were \$3,499,000 (2016 - \$8,731,000) and all these amounts were paid during the year.

(d) Net movement in regulatory deferral account balances related to net income

Net movement in regulatory deferral account balances related to net income is \$1,681,000 (2016 - \$(7,908,000)) represents the adjustment to the net income for the year before net movement in regulatory deferral account balances for the effects of rate regulation in accordance with IFRS 14. The net movement figure of \$7,908,000 is comprised of higher net income of \$(626,000) and \$(1,055,000) for both regulatory account debit balances and regulatory account credit balances for rate regulation compared to the amounts that would be recorded under IFRS. The net movement figure of \$(7,908,000) for 2016 is comprised of lower net income of \$(6,639,000) and \$(1,269,000) for both regulatory account debit balances and regulatory account credit balances for rate regulation compared to the amounts that would be recorded under IFRS.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

10. BANK INDEBTEDNESS

The Utility has access to a permanent \$10 million line of credit. Effective August 25, 2017, the line of credit was increased temporarily to \$22 million. The temporary increase expires August 24, 2018. The account accrues interest on withdrawals at prime rate minus 0.75% per annum. The amount outstanding on the line of credit balance at year end was \$9.6 million (2016 - \$2.5 million).

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31 2017	December 31 2016
Trade payables	\$ 7,404	\$ 7,138
Employee compensation	1,328	989
Due to related parties (Note 19)	812	199
Other	1,301	209
	\$ 10,845	\$ 8,535

12. CONSTRUCTION FINANCING

	December 31 2017	December 31 2016
Construction financing, due December 31, 2017 bearing interest at 1.33% approved to a maximum of \$8.4 million	\$ -	\$ 8,400
Construction financing, due December 31, 2017 bearing interest at 1.40% approved to a maximum of \$14 million	-	13,985
Construction financing, due December 31, 2018 bearing interest at 2.139% approved to a maximum of \$8.4 million	8,400	-
Construction financing, due December 31, 2018 bearing interest at 2.139% approved to a maximum of \$14 million	13,985	-
	\$ 22,385	\$ 22,385

Construction financing balances are monies advanced from the Parent to assist in the development of the Utility's infrastructure. Interest is payable annually at December 31 and at the maturity date.

During the year the Utility did not make any principal repayments.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

13. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	December 31 2017	December 31 2016
Yukon Development Corporation		
\$92,458,473 term note bearing interest at 2.40% repayable in annual installments of \$3,683,800 principal, plus accrued interest with the balance of \$77,726,473 due December 31, 2019	\$ 81,407	\$ 85,091
\$21,900,000 flexible term note bearing interest up to 5.46% repayable in annual installments of \$336,923 principal, plus accrued interest with the balance of \$8,423,078 due December 31, 2051 (i)	19,878	20,215
\$5,505,000 term note bearing interest at 2.40% interest only payable annually, due December 31, 2039	5,505	5,505
\$20,984,404 term note bearing interest at 2.21% repayable in annual installments of \$839,376 principal, plus accrued interest with the balance due December 31, 2040	19,306	20,145
\$12,136,000 term note bearing interest at 2.10% interest only payable annually, due December 31, 2041 (ii)	12,136	12,136
TD Bank		
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptances amounts from a variable interest rate based on the Bankers' Acceptances rates to a fixed rate of 2.69% per annum. Payable in monthly installments of \$50,407 interest and principal with the balance due on December 28, 2022 (iii)	9,348	9,697
Carmacks Stewart First Nation Liability		
Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non-interest bearing, repayable in varying installments, due in 2028	191	220
	147,771	153,009
Less current portion	5,248	5,238
	\$ 142,523	\$ 147,771

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

13. LONG-TERM DEBT - continued

(i) **\$21,900,000 Flexible Term Note**

The terms of the flexible term note provide for a maximum amount of interest payable within a calendar year, calculated based on the actual grid generation on the electrical grid system connected with the Mayo Hydro Enhancement Project. The amount of interest payable as a result of the interest rate exceeding the maximum interest payable will abate forever. The actual interest rate on this flexible note was 0.81% (2016 - 0.81%).

(ii) **Debt Refinancing**

On December 31, 2016, the Utility entered into an agreement with YDC to convert \$9,295,000 of existing construction financing with YDC into long-term debt (Notes 11 and 12) and borrow \$2,841,000 declared as a dividend to YDC at year end to maintain its capital structure (Note 25).

(iii) **TD Bank Loan and Interest Rate Swap**

On December 28, 2012, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures December 28, 2022.

Long-term debt repayment

Scheduled repayments for all long-term debt are as follows:

2018	\$ 5,218
2019	79,283
2020	1,570
2021	1,570
2022	9,074
Thereafter	51,056
	\$ 147,771

The change in long-term debt arising from financing activities during the year related to principal repayment of \$5,238. An amount of \$5,248 was reclassified from long-term debt to current portion of long-term debt due to the passage of time.

Fair value

The fair value of long-term debt at December 31, 2017 is \$146 million (2016 - \$154 million). The fair value for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

14. POST-EMPLOYMENT BENEFITS

Characteristics of benefit plans

The Utility sponsors a defined benefit pension plan for employees joining the Utility before January 1, 2002 and a defined benefit pension plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the employee defined benefit pension plan. The Utility makes contributions to a Registered Retirement Savings Plan ("RRSP") on behalf of these employees and employees hired before January 1, 2002 who belonged to the employee defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution plan. The costs recognized for the period are equal to the Utility's contribution to the plan. During 2017, these were \$454,000 (2016 - \$448,000).

The employee defined benefit pension plan and the defined benefit pension plan for a former executive are regulated by the Office of the Superintendent of Financial Institutions (OSFI) through the *Pension Benefits Standards Act* and regulations. This Act and accompanying regulations impose, among other things, minimum funding requirements.

These minimum funding requirements require the Utility make special payments as prescribed by the OSFI to repay any unfunded liability or deficit that may exist. For the employee defined benefit pension plan the Utility is required to pay \$87,300 as a minimum annual payment in each of the next 12 years (2016 - \$225,300 in each of the next 12 years).

A committee of the Utility's Board of Directors oversees these plans and is responsible for the investment policy with regard to the assets of these funds.

Risks associated with defined benefit plans

The defined benefit pension plans expose the Utility to risk such as investment risk and actuarial risk. Investment risk is the risk that the assets invested will be insufficient to meet expected benefits. Actuarial risk is the risk that benefits paid will be more than expected. There are no particular unusual, entity-specific or plan-specific risks or any significant concentration of risk.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

14. POST-EMPLOYMENT BENEFITS - continued

Net defined benefit liability

	December 31 2017	December 31 2016
Present value of benefit obligations		
Balance, beginning of year	\$ 22,980	\$ 20,793
Employee Contributions	84	84
Current service cost	543	493
Interest cost	910	868
Benefits paid	(559)	(458)
Actuarial losses (gains) on experience	(755)	539
Actuarial losses (gains) on financial assumptions	1,572	661
Balance, end of year	\$ 24,775	\$ 22,980
Fair value of plan assets		
Balance, beginning of year	17,113	15,357
Interest income on plan assets	671	638
Gains (losses) on plan assets	688	716
Employee contributions	84	84
Employer contributions	673	781
Benefits paid	(521)	(421)
Administrative costs	(50)	(42)
Balance, end of year	18,658	17,113
Net defined benefit liability	\$ 6,117	\$ 5,867

Components of benefit plan cost:

	December 31 2017	December 31 2016
Current service cost	\$ 543	\$ 493
Interest cost	910	868
Interest income on plan asset	(671)	(638)
Administrative costs	50	42
Defined benefit expense in Statement of Operations	832	765
Defined contribution expense	77	448
Total benefit expense in Statement of Operations	\$ 909	\$ 1,213
Actuarial losses (gains) on obligation	765	1,200
(Gains) losses on plan assets	(688)	(717)
Total re-measurements included in Other Comprehensive Income	77	483
Total benefit costs recognized in Statement of Operations and Other Comprehensive Income	986	1,696

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

14. POST-EMPLOYMENT BENEFITS - continued

Distribution of plan assets of defined benefit pension plans

The fair value of the defined benefit pension plans' assets are based on market values as reported by the defined benefit pension plans' custodians as at each applicable Statement of Financial Position date. The distribution of assets by major asset class is as follows:

	<u>December 31, 2017</u>	<u>December 31, 2016</u>
Equities	51.8%	54.9%
Fixed income securities	38.5%	35.9%
Real estate	9.7%	9.2%

Significant assumptions:

	<u>December 31, 2017</u>	<u>December 31, 2016</u>
Discount rate - accrued benefit obligation	3.40 - 3.50%	3.90 - 4.00%
Assumed rate of salary escalation	2.80 - 3.50%	2.80 - 3.50%
Pension growth	2.00 - 2.50%	2.00 - 2.50%

Sensitivity analysis of the defined benefit pension plans:

The sensitivities of each key assumptions used in measuring accrued benefit obligations at each Statement of Financial Position date have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously. The sensitivity analysis has been determined based on reasonably possible changes of the respective assumptions occurring at the end of the reporting period. The mortality assumptions are based on the 2014 Canadian Pensioner Mortality Private Table projected with full generational mortality improvements using scale B.

Assumptions and sensitivity as at December 31, 2017

Assumption	+1%	-1%	+1%	-1%
Discount rate	-14.29%	18.14%	\$ (3,540)	\$ 4,494
Salary growth	2.18%	-2.07%	508	(483)
Pension growth	14.48%	-11.93%	3,378	(2,784)
Life expectancy (1 year movement)	2.63%	-2.64%	652	(655)

Assumptions and sensitivity as at December 31, 2016

Assumption	+1%	-1%	+1%	-1%
Discount rate	-14.1%	17.9%	\$ (3,241)	\$ 4,129
Salary growth	2.5%	-2.4%	550	(521)
Pension growth	14.2%	-11.7%	3,071	(2,537)
Life expectancy (1 year movement)	2.4%	-2.4%	555	(559)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

14. POST-EMPLOYMENT BENEFITS - continued

The sensitivity analysis presented above may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Furthermore, in presenting the above sensitivity analysis, the present value of the defined benefit obligation has been calculated using the projected unit credit method at the end of the reporting period, which is the same that is applied in calculating the defined benefit obligation liability recognized in the Statement of Financial Position.

The Utility pays the balance of the cost of the Plan over the employee contributions, as determined by the actuary. Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings (YMPE) plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. Employees can make additional contributions to purchase ancillary benefits. Members choose the ancillary benefit on termination of service or on retirement.

The average duration of the benefit obligation is 16.0 years (2016 - 16.0 years). The Utility expects to make payments of \$672,000 (2016 - \$706,000) to the defined benefit plans during the next financial year.

15. CONTRIBUTIONS IN AID OF CONSTRUCTION

	Government of Canada	Parent since 1998	Customer since 1998	Yukon Government since 1998	Pre-1998 contributions	Total
Cost:						
At December 31, 2015	\$ 71,000	\$ 91,810	\$ 24,579	\$ 11,040	\$ 1,739	\$ 200,168
Additions	-	-	274	58	-	332
At December 31, 2016	71,000	91,810	24,853	11,098	1,739	200,500
Additions	-	-	41	291	-	332
At December 31, 2017	\$ 71,000	\$ 91,810	\$ 24,894	\$ 11,389	\$ 1,739	\$ 200,832
Accumulated amortization:						
At December 31, 2015	\$ 4,039	\$ 7,911	\$ 8,761	\$ 1,625	\$ 1,292	\$ 23,628
Amortization	990	1,680	1,179	209	44	4,102
At December 31, 2016	5,029	9,591	9,940	1,834	1,336	27,730
Amortization	991	1,612	1,255	213	43	4,114
At December 31, 2017	\$ 6,020	\$ 11,203	\$ 11,195	\$ 2,047	\$ 1,379	\$ 31,844
Net book value:						
At December 31, 2016	\$ 65,971	\$ 82,219	\$ 14,913	\$ 9,264	\$ 403	\$ 172,770
At December 31, 2017	\$ 64,980	\$ 80,607	\$ 13,699	\$ 9,342	\$ 360	\$ 168,988

The sources of contributions received prior to 1998 were not recorded separately.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

16. DECOMMISSIONING FUND

	December 31 2017	December 31 2016
Opening balance	\$ 2,636	\$ 2,612
Interest	29	24
Closing balance	\$ 2,665	\$ 2,636

17. SALES OF POWER

	2017	2016
Wholesale	\$ 35,334	\$ 28,641
Industrial	5,298	4,506
General service	4,924	4,359
Residential	2,494	2,040
Secondary sales	635	371
Sentinel and street lights	104	96
	\$ 48,789	\$ 40,013

18. OPERATIONS AND MAINTENANCE EXPENSES

	2017	2016
Regulatory account expenses (Note 9 (c))	\$ 3,751	\$ 8,731
Wages and benefits	6,182	5,955
Contractors	3,176	1,692
Materials and consumables	1,335	1,173
Fuel	2,911	1,168
Travel	352	311
Rent	436	234
Communication	69	58
	\$ 18,212	\$ 19,322

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

19. ADMINISTRATION EXPENSES

	2017	2016
Wages and benefits	\$ 5,711	\$ 5,737
Materials, consumables and general	1,007	2,273
Insurance and taxes	1,816	1,812
External labour	1,231	1,189
Licences and fees	711	658
Travel	181	171
Board fees	55	83
	\$ 10,712	\$ 11,923

20. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all YG departments, agencies and Territorial Corporations. Transactions are entered into in the normal course of operations with these entities. All sales transactions are recorded at the rates approved by the YUB.

Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers. These revenues are included in sales of power on the Statement of Operations and Other Comprehensive Income.

The following table summarizes the Utility's related party transactions for the year:

	2017	2016
Revenue		
Sales of service to YDC	\$ 4	\$ 6
Rate subsidy received from YDC	299	299
Funding from YDC	-	825
Operating expenses		
Interest expense on borrowings from YDC	\$ 3,957	\$ 3,220
Dividend to YDC	\$ -	\$ 2,841
Other receipts		
Construction financing from YDC	-	8,400
Other payments		
Repayment of long-term debt from YDC	\$ 4,860	\$ 4,860

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

20. RELATED PARTY TRANSACTIONS - continued

Other related party transactions and balances are as disclosed elsewhere in these financial statements (Notes 11 and 12).

Funding from YDC of \$825,000 is for feasibility studies for the Stewart Keno Transmission Line.

At the end of the year, the amounts receivable from and due to related parties are as follows:

	December 31 2017	December 31 2016
YDC		
Accounts receivable	\$ 30	\$ 28
Accounts payable	442	167
Construction financing	22,385	22,385
Current portion of long-term debt	4,860	4,860
Long-term debt	133,373	138,233
YG		
Accounts receivable	\$ 343	\$ 62
Accounts payable	42	32

These balances are non-interest bearing and payable on demand except for construction financing and long-term debt.

Transactions with Key Management Personnel

The Utility's key management personnel include members of the senior management team and the Board of Directors, a total of 16 individuals (2016 - 18 individuals). Key management personnel compensation is as follows:

Year ended December 31	2017	2016
Short-term employee benefits	\$ 1,591	\$ 1,537
Post-employment benefits	182	59
	\$ 1,773	\$ 1,596

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

21. COMMITMENTS

Aishihik water licence

The Yukon Water Board issued a water use licence in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this licence commits the Utility to meet a number of future requirements including annual fish monitoring programs.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2019. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

Contractual obligations

The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31, 2017 as the product or service had not been provided. The total commitments at year end are \$6,101,000 (2016 - \$1,754,000).

22. CONTINGENCIES

Aishihik Third Turbine Project

This project was commissioned into service in December 2011. On March 2, 2012, the general contractor filed a claim with the Supreme Court of Yukon for \$4,000,000 plus interest and costs alleging the Utility has not paid for work performed. During 2016, the judge awarded the plaintiff \$1,682,000 of which \$1,308,000 had already been accrued for in the financial statements. The Utility is also required to reimburse the plaintiff for its legal costs and interest. The Utility has recognized an estimate for this amount as a liability in the Statement of Financial Position. The Utility has appealed the decision. The outcome of the appeal is not determinable at this time and no estimate of appeal settlement has been recognized in the financial statements.

Asset Retirement Obligations

The Utility has not recognized a provision for the closure and restoration obligations for certain generation, transmission and distribution assets which the Utility anticipates maintaining and operating these assets for an indefinite period, making the date of retirement of these assets indeterminate. These significant uncertainties around the timing of any potential future cash outflows are such that a reliable estimate of the liability is not possible at this time. A provision will be recognized when the timing of the retirement of these assets can be reasonably estimated.

23. PROVISION FOR ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations.

The Utility has conducted environmental site assessments at all its diesel plant sites. At sites where environmental contamination was found and a legal obligation to remediate the site existed, the Utility has conducted a full remediation. As at December 31, 2017 no new provisions for environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility will continue to use its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis. The Utility does not have a provision for environmental liabilities as there is no present obligation to remediate.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2017, the Utility's financial instruments included cash, accounts receivable, accounts payable and accrued liabilities, construction financing, long-term debt and interest rate swaps. The fair value of cash, accounts receivable, accounts payable and accrued liabilities and construction financing approximate their carrying value due to the immediate or short-term maturity of these financial instruments.

The long-term debt is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term debt is estimated by discounting the future cash flows using current rates for debt instruments subject to similar risks and maturities as disclosed in Note 12.

Interest rate swaps are financial contracts that derive their value from changes in an underlying variable. The Utility's interest rate swaps are classified as held for trading and are recognized at their fair value on the date the contract has been entered into. Any subsequent unrealized and realized gains and losses are reported in net income during the period in which the fair value movement occurred. The fair value of the interest rate swaps is estimated using standard market valuation techniques and is provided to the Utility by the financial institution that is the counterparty to the transactions.

The Utility did not engage in any other hedging transactions.

Interest rate risk

Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility's future cash flows are not exposed to significant interest rate risk due to its long-term debt having fixed interest rates, with the exception of the Bankers' Acceptances from the TD Bank. The Bankers' Acceptances have had the variable rate converted to a fixed rate using an interest rate swap to eliminate the interest rate risk.

As at December 31, 2017, the Utility had an interest rate swap agreement in place with a notional principal amount of \$9.4 million (2016 - \$9.7 million). The agreement effectively changes the Utility's interest rate exposure on this notional amount from a floating rate to a fixed rate of 2.69%.

The fair value of the interest rate swap agreement on December 31, 2017 was a liability of \$56,000 (2016 - liability of \$409,000). The increase in the fair value in 2017 of \$353,000 (2016 – increase of \$144,000) is recognized on the Statement of Operations and Other Comprehensive Income as an unrealized gain or loss. A 100 basis point increase or decrease in the interest rate assumption would have resulted in an increase/decrease in the interest rate swap agreements fair value of \$401,000 (2016 - \$498,000).

The Utility has access to a \$10 million line of credit. Effective August 25, 2017, the line of credit was increased temporarily to \$22 million. The temporary increase expires August 24, 2018. The account accrues interest on withdrawals at prime rate minus 0.75% per annum. By agreement the financial institution has a legally enforceable right to set off the outstanding balance under the line of credit by cash balances in other accounts with the same bank. The amount outstanding on the line of credit balance at year end was \$10.1 million (2016 - \$2.5 million). The Utility has cash balances with the same financial institution of \$2.8 million (2016 - \$2.8 million). Due to the short-term nature of the amount drawn on the line of credit and the Utility's cash balances with the same financial institution, the interest rate risk is minimal.

Credit risk

Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

The following table illustrates the maximum credit exposure to the Utility if all counterparties defaulted:

	December 31 2017	December 31 2016
Cash	\$ -	\$ 551
Accounts receivable	12,427	5,873
	\$ 12,427	\$ 6,424

Credit risk on cash is considered minimal as the Utility's cash deposits are held by a Canadian Schedule 1 Chartered bank.

Credit risk on accounts receivable is considered minimal as the Utility has experienced insignificant bad debt in prior years. In addition, its primary customer is a rate regulated utility that purchases power from the Utility for resale and as such these receivables are considered fully collectible. Included in the accounts receivable past due but not impaired at December 31, 2017 are \$1,222,000 (2016 - \$257,000) which management believes will be received in full.

Liquidity risk

Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility manages liquidity risk through regular monitoring of cash and currency requirements by preparing cash flow forecasts to identify financing requirements. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

The Utility's largest current liability is current portion long-term debt which is predominantly due to the parent, and the Utility has successfully renegotiated this debt in prior years. In addition, rate regulation assists the Utility with liquidity management by providing consistent revenues and a consistent debt to equity ratio.

Fair values

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2017:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	\$56	-	\$56
Long-term debt	-	-	\$148,000	\$148,000

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2016:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	\$409	-	\$409
Long-term debt	-	-	\$154,000	\$154,000

25. CAPITAL MANAGEMENT

The Utility's capital is its shareholder's equity which is comprised of share capital, contributed surplus and retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year. Short term debt related to assets under construction at the Statement of Financial Position date is excluded from the calculation of total debt, as the assets are similarly excluded from the determination of rate base. In addition the provision for decommissioning of the Minto Mine spur line has been added (Note 15). Total capitalization is calculated as total debt plus total shareholder's equity as shown on the Statement of Financial Position. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

The Utility has a policy which defines its capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2017

25. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility's total debt to total capitalization position:

	December 31	
	2017	2016
Long-term debt due within one year	\$ 5,248	\$ 5,238
Long-term debt	142,523	147,771
Total debt	147,771	153,009
Add provision for decommissioning of industrial customer spur line	2,665	2,636
Total debt to include in the calculation	\$ 150,436	\$ 155,645
Share capital	\$ 39,000	\$ 39,000
Contributed surplus	14,600	14,600
Retained earnings	61,075	51,034
Total shareholder's equity	114,675	104,634
Total capitalization	\$ 265,111	\$ 260,279
Total debt to total capitalization	57 %	60 %

There were no changes in the Utility's approach to capital management during the period.

YUKON ENERGY CORPORATION
UTILITY INCOME AND RATE OF RETURN
For The Year Ended December 31
(\$000s)

	2017
Utility Revenue	
Utility Electric Sales	51,564
Other Revenue	319
Total	51,883
Utility Expense	
Labour	11,894
Non-Labour	
Operations and Maintenance	5,591
Administration	2,731
Insurance	1,032
Donations	96
Fuel	4,849
Purchased Power	49
Total Operating and Maintenance Costs	26,241
Depreciation & Amortization	
Fixed Asset Depreciation	11,765
Amortization of Deferred Costs (incl. RFID)	4,986
Amortization of Contribution for Extensions	(5,539)
Amortization of Fire Insurance Gain	(262)
Other Taxes	693
Total Expenses	37,884
Less: Donations	96
Disallowed Depreciation	16
Total	37,773
Utility (Regulatory) Income	14,110
Net Rate Base	274,320
Rate Of Return on Capital	5.14%
<i>Rate of Return on Equity</i>	<i>8.72%</i>
<i>Cost of Debt</i>	<i>2.58%</i>

YUKON ENERGY CORPORATION
COMPUTATION OF NET RATE BASE
For The Year Ended December 31
(\$000s)

	2017
Property, Plant and Equipment	598,756
Less: Work in progress (includes deferred cost WIP)	19,740
Accumulated Depreciation	150,301
Reserve for Future Removal and Site Restoration	4,303
Deferred Fire Gain	4,966
Customer Contributions (excluding for WIP)	168,967
Subtotal	250,479
Add: Deferred Study, Relicensing & Regulatory Costs	30,301
Accumulated Disallowed Depreciation	184
Less: Disallowed Assets	691
Reserve for Injuries and Damages	(1,247)
Net balance at year end	281,519
Mid-year balance	266,462
Add: Allowance for Working Capital	5,456
Mid-Year Rate Case Expense	2,402
Net Rate Base	274,320

**YUKON ENERGY CORPORATION
WORKING CAPITAL CALCULATION
For The Year Ended December 31
(\$000s)**

	2017
Working Capital	
Operation and Maintenance	26,241
Add: Other Taxes	693
Less: Donations and Disallowed expenses	96
Allowable Operating Expense	26,838
Allowance: Operating Expense (27/365 * Allowable Operating Expense)	1,985
Three Year Average Inventory	3,665
GST Impact	(194)
Total Working Capital	5,456

YUKON ENERGY CORPORATION
RECONCILIATION OF UTILITY INCOME TO NET EARNINGS
For The Year Ended December 31
(\$000s)

	2017
Utility Income	14,110
Add Non Utility Income:	
Allowance for Funds Used During Construction	466
Other Income	-
Sub-Total	14,576
Less Non Utility Expenses:	
Long Term Interest	4,246
Other Interest	(222)
Capital Lease Interest	-
Donations	96
Disallowed Expenses	150
Disallowed Depreciation	16
Net Earnings	10,290

YUKON ENERGY CORPORATION
SUMMARY OF CAPITAL ASSETS
For The Year Ended December 31
(\$000s)

	2017
Capital Assets	
Land	1,720
Hydro, LNG, Wind and Diesel Plants	351,203
Transmission	184,219
Distribution	17,462
Buildings, Office and General Equipment	34,045
Transportation	5,348
Construction Work-in-Progress	4,759
Cost	598,756
Less: Accumulated Depreciation	150,301
Net Book Value	448,456
Less: Net Contribution for Extensions	168,967
Net Capital Assets	279,489

**YUKON ENERGY CORPORATION
COST OF CAPITAL CALCULATION
For The Year Ended December 31
(%)**

2017	Capital Ratio	Cost	Return Component
Mid-year Long Term Debt	58.2	2.58	1.500
Mid-year Common Equity	41.8	8.72	3.643
	100.0		5.14

YUKON ENERGY CORPORATION
BOARD OF DIRECTORS AND OFFICERS
(as at March 29, 2018)

DIRECTORS	
LESLEY CABOTT, Chair	SUE CRAIG
JOANNE FAIRLIE	JOHN JENSEN
GARY JONES	SIMON LAPOINTE
CLINT MCCUAIG	CURTIS SHAW
ERIN STEHELIN	WENDY SHANKS
OFFICERS	
ANDREW HALL President and CEO	ED MOLLARD Chief Financial Officer
KELLY POLLARD Corporate Secretary	

1 **TOPIC:**

2
3 **REFERENCE: December 18, 2017 Alternative GRA Forecast Submission**

4
5 *Tab 9 – 2015 Audited Financial Statements*

6
7 **PREAMBLE:**

8
9 **QUESTION:**

10
11 a) Please provide YEC's 2016 Audited Financial Statements.

12
13 **ANSWER:**

14
15 **(a)**

16
17 YEC's 2016 Audited Financial Statements are provided as UCG-YEC-2-43
18 Attachment 1.

Yukon Energy Corporation

Financial Statements

December 31, 2016

Management's Responsibility for Financial Reporting	26
Independent Auditor's Report	27-28
Statement of Financial Position	29
Statement of Operations and Other Comprehensive Income	29
Statement of Changes in Equity	31
Statement of Cash Flows	32
Notes to Financial Statements	33-66

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the financial statements and all other financial information relating to the Utility contained in this annual report. The financial statements have been prepared in conformity with International Financial Reporting Standards using methods appropriate for the industry in which the Utility operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the financial statements. The Auditor General of Canada is the external auditor of the Corporation.

Management has established internal accounting control systems to meet its responsibilities for reliable and accurate reporting. These systems include policies and procedures, the careful selection and training of qualified personnel and an organizational structure that provides for the appropriate delegation of authority and segregation of responsibilities.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management and the independent auditor to discuss auditing and financial matters to assure that management is carrying out its responsibilities and to review the financial statements. The auditors have full and free access to the Audit Committee and management.



Andrew Hall
President and CEO



Ed Mollard
Chief Financial Officer

May 10, 2017



Office of the
Auditor General
of Canada

Bureau du
vérificateur général
du Canada

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of the Yukon Energy Corporation

Report on the Financial Statements

I have audited the accompanying financial statements of the Yukon Energy Corporation, which comprise the statement of financial position as at 31 December 2016, and the statement of operations and other comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Yukon Energy Corporation as at 31 December 2016, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Report on Other Legal and Regulatory Requirements

In my opinion, the transactions of the Yukon Energy Corporation that have come to my notice during my audit of the financial statements have, in all significant respects, been in accordance with the *Public Utilities Act* and regulations, the *Business Corporations Act* and regulations and the articles and by-laws of the Yukon Energy Corporation.



David Irving, CPA, CA
Principal
for the Auditor General of Canada

10 May 2017
Edmonton, Canada

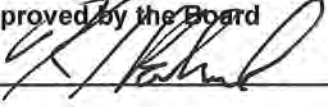
Yukon Energy Corporation
Statement of Financial Position
(in thousands of Canadian dollars)

As at	December 31 2016	December 31 2015
Assets		
Current		
Cash	\$ 551	\$ 1,672
Accounts receivable (Note 5)	5,873	6,347
Inventories (Note 6)	3,597	3,614
Prepaid expenses	754	828
	10,775	12,461
Non-current		
Property, plant and equipment (Note 7)	444,354	443,194
Intangible assets (Note 8)	7,281	6,992
Total assets	462,410	462,647
Regulatory deferral account debit balances (Note 9)	27,880	21,241
Total assets and regulatory deferral account debit balances	\$ 490,290	\$ 483,888
Liabilities		
Current		
Accounts payable and accrued liabilities (Note 10)	\$ 8,535	\$ 7,310
Construction financing (Note 11)	22,385	23,280
Derivative related liability (Note 23)	409	553
Current portion of long-term debt (Note 12)	5,238	6,066
	36,567	37,209
Non-current		
Post-employment benefits (Note 13)	5,867	5,436
Contributions in aid of construction (Note 14)	172,770	176,540
Decommissioning fund (Note 15)	2,636	2,612
Long-term debt (Note 12)	147,771	140,874
Total liabilities	365,611	362,671
Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued and fully paid: 3,900 shares	39,000	39,000
Contributed surplus	14,600	14,600
Retained earnings	51,034	46,303
Total equity	104,634	99,903
Total liabilities and equity	470,245	462,574
Regulatory deferral account credit balances (Note 9)	20,045	21,314
Total liabilities, equity and regulatory deferral account credit balances	\$ 490,290	\$ 483,888

Commitments and Contingencies (Notes 20 and 21)

The accompanying notes are an integral part of these financial statements.

Approved by the Board

 , Chair

 , Director

Yukon Energy Corporation
Statement of Operations and Other Comprehensive Income
(in thousands of Canadian dollars)

For the year ended December 31	2016	2015
Revenues		
Sales of power (Note 16)	\$ 40,013	\$ 40,948
Funding from parent (Note 19)	825	6,135
Other	287	383
	41,125	\$ 47,466
Operating expenses		
Operations and maintenance (Note 17)	19,322	17,376
Administration (Note 18)	11,923	9,891
Depreciation and amortization (Notes 7 and 8)	11,262	10,438
	42,507	37,705
(Loss) Income from operations	(1,382)	9,761
Other income		
Allowance for funds used during construction	819	714
Amortization of contributions in aid of construction (Note 14)	4,102	3,624
Unrealized gain on interest rate swap (Note 23)	144	-
	5,065	4,338
Other expenses		
Interest on borrowings	3,536	3,319
Unrealized loss on interest rate swap (Note 23)	-	340
	3,536	3,659
Net income for the year before net movements in regulatory deferral account balances	147	10,440
Net movement in regulatory deferral account balances related to net income (Note 9 (d))	7,908	(2,725)
Net income for the year and net movements in regulatory deferral account balances	8,055	7,715
Other Comprehensive Income (Note 3 (o))		
Item that will not be reclassified to net income in subsequent periods		
Re-measurement of defined benefit pension plans (Note 13)	(483)	512
Total comprehensive income for the year	\$ 7,572	\$ 8,227

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Changes in Equity
(in thousands of Canadian dollars)

	Share Capital Number of shares	\$	Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at December 31, 2014	3,900	\$ 39,000	\$ 14,600	\$ 38,076	-	\$ 91,676
Net income for the year and net movement in regulatory deferral account balances	-	-	-	7,715	-	7,715
Other comprehensive income	-	-	-	-	512	512
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	512	(512)	-
Balance at December 31, 2015	3,900	\$ 39,000	\$ 14,600	\$ 46,303	-	\$ 99,903
Net income for the year and net movement in regulatory deferral account balances	-	-	-	8,055	-	8,055
Other comprehensive income	-	-	-	-	(483)	(483)
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	(483)	483	-
Dividends	-	-	-	(2,841)	-	(2,841)
Balance at December 31, 2016	3,900	\$ 39,000	\$ 14,600	\$ 51,034	-	\$ 104,634

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Cash Flows
(in thousands of Canadian dollars)

For the year ended December 31	2016	2015
Operating activities		
Cash receipts from customers	\$ 40,814	\$ 42,072
Cash receipts from parent	825	2,000
Cash receipts from contributions in aid of construction	332	739
Cash paid to suppliers	(17,464)	(16,906)
Cash paid to employees	(11,640)	(11,341)
Interest paid	(3,473)	(3,319)
Cash provided by operating activities	9,394	13,245
Financing activities		
Receipt of construction financing	8,400	11,200
Repayment of construction financing	-	(8,400)
Issuance of long-term debt	-	20,984
Repayment of long-term debt	(6,067)	(5,455)
Cash provided by financing activities	2,333	18,329
Investing activities		
Additions to property, plant and equipment	(11,530)	(28,024)
Additions to intangible assets	(1,318)	(707)
Cash used in investment activities	(12,848)	(28,731)
Net (decrease) increase in cash	(1,121)	2,843
Cash, beginning of year	1,672	(1,171)
Cash, end of year	\$ 551	\$ 1,672

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

1. NATURE OF OPERATIONS

a) General

Yukon Energy Corporation ("the Utility") is incorporated under the Yukon *Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation ("YDC" or "the Parent"), a corporation owned by the Yukon Government ("YG" or "the Government"). The Utility generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes. The Utility's principal place of business is located at #2 Miles Canyon Road, Whitehorse, Yukon, Y1A 6S7.

The Utility is subject to overall regulation by the Yukon Utilities Board (YUB) and specific regulation by the Yukon Water Board. Both boards are consolidated by the Government and as such are considered to be related parties for accounting purposes. Management has assessed that these boards operate independently from the Utility from a rate setting and operating perspective.

b) Rate regulation

The operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility files a General Rate Application (GRA) for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principles of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the YG through Orders-In-Council ("OIC") that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility expects it will incur to provide electricity to its customers over the immediate future are reviewed and approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the depreciation of all capital equipment; and
- the return on rate base (the borrowing costs related to borrowing that portion of rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of rate base which is financed with equity).

The YUB assesses the prudence of costs added to rate base, which includes an allowance for funds used during construction ("AFUDC") charged to capital projects. The YUB also reviews the appropriateness of property, plant and equipment depreciation rates, which are periodically updated by the Utility through depreciation studies.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: residential, government, commercial and industrial. This process is guided mainly by requirements of OIC 1995/90 and can include a cost-of-service study which allocates the Utility's overall cost of service to the various customer classes on the basis of appropriate costing principles.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

1. NATURE OF OPERATIONS - continued

c) Water regulation

The Yukon Water Board, pursuant to the Yukon *Waters Act*, decides if and for how long the Utility will have a water license for the purposes of operating hydro generation stations in the Yukon. The licenses will also indicate terms and conditions for the operation of these facilities.

d) Capital structure

The Utility's policy which has been approved by the YUB is to maintain a capital structure of 60% debt and 40% equity (Note 24). Dividends are normally declared annually to the Parent and are typically loaned back in order to maintain this ratio during normal on-going operations. When large assets are purchased or constructed, the Parent may be required to make an equity or capital contribution.

2. BASIS OF PRESENTATION

a) Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

These financial statements were authorized for issue by the Board of Directors on May 10, 2017.

b) Basis of measurement

The financial information included in the financial statements has been prepared on a historical cost basis, except for financial instruments which are measured at fair value.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied to all periods presented in these financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

3. SIGNIFICANT ACCOUNTING POLICIES - continued

a) Revenue recognition

All revenues are recognized in the period earned. Revenue from the sale of power is recognized based on cyclical meter readings. Sales of power includes an accrual for electricity deliveries not yet billed at year-end.

b) Translation of foreign currencies

The functional currency of the Utility is the Canadian Dollar. Revenue and expense items denominated in foreign currencies are translated at exchange rates prevailing during the period. Monetary assets and liabilities denominated in foreign currencies are translated at period-end exchange rates. Non-monetary assets and liabilities are translated at exchange rates in effect when the assets are acquired or the obligations are incurred. Foreign exchange gains and losses are reflected in net income for the period.

c) Allowance for funds used during construction

The cost of the Utility's property, plant and equipment and deferred charges includes an allowance for funds used during construction (AFUDC) as allowed by the regulator. The AFUDC rate is based on the Utility's weighted average cost of debt.

d) Cash

Cash is comprised of bank account balances (net of outstanding cheques).

e) Inventories

Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. Inventories are carried at the lesser of weighted average cost and net realizable value. Cost includes all expenditures incurred in acquiring the items and bringing them to their existing condition and location. Critical spare parts are recognized in the Utility's property, plant and equipment.

The recoverable value of inventory considers its net realizable value, including required processing costs, and is impacted by estimates and assumptions on prices, quality, recovery and exchange rates. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

f) Financial instruments

Financial assets and financial liabilities are recognized on the Utility's Statement of Financial Position when the Utility becomes party to the contractual provisions of the instrument. Accounts receivable, classified as loans and receivables, are initially measured at fair value. Subsequent to initial recognition, accounts receivable are measured at amortized cost using the effective interest rate method less any impairment.

A provision for impairment of accounts receivable is established when there is objective evidence that the Utility will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulties of the debtor, probability that the debtor will enter into bankruptcy or require financial reorganization, and default or delinquency in payments are considered indicators that the related accounts receivable are impaired. The accounts receivable carrying amount is reduced through the use of an allowance account and the loss is recognized in net income.

Cash, accounts payable and accrued liabilities, construction financing and long-term debt are classified as other financial liabilities and they are initially recognized at fair value. Subsequent to initial recognition, they are measured at amortized cost using the effective interest rate method (except for cash which is measured at cost).

Transaction costs are presented as a reduction from the carrying value of the related debt and are amortized using the effective interest rate method over the terms of the debts to which they relate. Transaction costs include fees paid to agents, brokers and advisors but exclude debt discounts and lender financing costs.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

3. SIGNIFICANT ACCOUNTING POLICIES - continued

f) Financial instruments - continued

Derivative financial instruments are financial contracts that derive their value from changes in an underlying variable. The Utility has entered into an interest rate swap to manage interest rate risk. The Utility's interest rate swap is classified as held for trading and is thus recognized at fair value on the date the contract has been entered into with any subsequent realized and unrealized gains and losses recognized in net income during the period in which the fair value movement occurred.

g) Property, plant and equipment

Property, plant and equipment are carried at cost, less accumulated depreciation and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs, AFUDC and any asset retirement costs associated with the property, plant and equipment.

AFUDC is based on the Utility's weighted average cost of borrowing and is applied to actual costs in work-in-progress less any contributions in aid of construction. For items of property, plant and equipment acquired prior to January 1, 2011, the AFUDC rate also included a regulatory cost of equity component as allowed by the YUB. Capitalization of AFUDC ceases when the asset being constructed is substantially ready for its intended purpose.

Assets under construction are recognized as in construction work in progress until they are operational and available for use, at which time they are transferred to the applicable component of property, plant and equipment.

Depreciation is recognized in net income based on the straight-line method over the estimated useful life of each major component of property, plant and equipment. The range of the estimated useful lives of the major classes and subclasses of property, plant and equipment is as follows:

Generation	
Hydroelectric plants	30 to 103 years
Thermal plants	12 to 72 years
Wind turbines	30 years
Transmission	20 to 65 years
Distribution	12 to 55 years
Buildings	20 to 55 years
Transportation	9 to 31 years
Other equipment	5 to 20 years

Depreciation commences when an asset is available for use. The estimated useful lives of the assets are based upon depreciation studies conducted periodically by the Utility and any changes in the estimated useful lives are accounted for prospectively.

Gains and losses on the disposal or retirement of property, plant and equipment, with the exception of land and vehicles, are deferred and amortized over the remaining expected useful life of the related assets under regulatory accounting (Note 9). These gains and losses are recognized immediately in net income under IFRS.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

3. SIGNIFICANT ACCOUNTING POLICIES - continued

g) Property, plant and equipment - continued

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period of the expected useful life (until the next major overhaul) which varies from 5 to 10 years. However, major overhaul costs cannot be depreciated for regulatory purposes until the costs are approved by the YUB (Note 9). Repairs and maintenance costs of property plant and equipment are expensed as incurred unless they meet the criteria of a betterment.

h) Intangible assets

Intangible assets are carried at cost less accumulated amortization and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs and AFUDC.

Amortization is recognized in net income on a straight-line basis over the estimated useful lives as follows:

Software	5 years
Deferred customer service costs	12 years
Financial software	10 years
Licencing costs	
Hydro generation	17 to 25 years
Diesel generation	3 years

i) Impairment of non-financial and financial assets

Property, plant and equipment, regulatory deferral debit balances and intangible assets with finite lives are reviewed for impairment on an annual basis if there is an indication that the carrying amount may not be recoverable. Impairment is assessed at the level of cash-generating units, which are identified as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or group of assets.

When an impairment review is undertaken, the recoverable amount is assessed by reference to the higher of value in use and fair value less costs to sell ("FVLCS") for non-financial assets and objective evidence of impairment in the case of financial assets. Value in use is the net present value of expected future cash flows of the relevant cash-generating unit in its current condition. The best evidence of FVLCS is the value obtained from an active market or binding sale agreement. Where neither exists, FVLCS is based on the best information available to reflect the amount the Utility could receive for the cash generating unit in an arm's length transaction. This is often estimated using discounted cash flow techniques and where unobservable inputs are material to the measurement of the recoverable amount, the measurement is classified as level 3 in the fair value hierarchy. The cash flow forecasts for FVLCS purposes are based on management's best estimates of expected future revenues and costs, including the future cash costs of production, capital expenditure, closure, restoration and environmental cleanup. For regulatory deferral debit balances the impairment review focuses on whether the amount is considered collectible based on the expected cash flows from the rates approved by the YUB.

These determinations and their individual assumptions require that management make a decision based on the best available information at each reporting period. Changes in these assumptions may alter the results of non-financial asset and financial asset impairment testing, impairment charges recognized in net income and the resulting carrying amounts of the assets.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

3. SIGNIFICANT ACCOUNTING POLICIES - continued

j) Rate regulated accounting policies

Regulatory deferral accounts

Regulatory deferral accounts in these financial statements are accounted for differently than they would be in the absence of rate regulation. Where regulatory decisions dictate, the Utility defers certain costs or revenues as regulatory deferral account debit balances or regulatory deferral account credit balances on the Statement of Financial Position and recognizes them in the net movement in regulatory deferral account balances in the Statement of Operations and Other Comprehensive Income as it collects or refunds amounts through future customer rates. Any adjustments to these regulatory deferral accounts are recognized in the net movement in regulatory deferral account balances in the period that the YUB renders a subsequent decision. All amounts maintained as regulatory deferral account debit balances and regulatory deferral account credit balances are expected to be recovered or settled and are assessed on a yearly basis by comparing the rates approved by the YUB to the current balances. The recovery or settlement of regulatory deferral account balances through future rates is impacted by demand risk and regulatory risks (e.g. potential future decisions of the YUB which could result in material adjustments to these regulatory deferral account debit balances and regulatory deferral account credit balances as described in Note 1(b)).

i) Regulatory deferral account debit balances

Regulatory deferral account debit balances represent incurred costs which have been deferred and are recognized or being amortized over various periods as approved by the YUB. Regulatory deferral account debit balances represent costs which are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such costs would be expensed as incurred.

ii) Regulatory deferral account credit balances

Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such amounts would be recorded in income as earned.

Note 9 describes the individual regulatory deferral accounts, the Utility's related regulatory deferral and amortization policies and describes the related account activity in the relevant periods.

k) Provision for asset retirement obligations

The Utility has legal obligations related to the closure and restoration of property, plant and equipment, which includes the costs of dismantling, demolition of infrastructure and the removal of residual materials and remediation of the disturbed areas.

Where a reliable estimate of the present value of these obligations can be determined, the total retirement costs are recognized as a provision in the accounting period when the obligation arises. There is also a corresponding increase to property, plant and equipment upon recognition of the obligation. Management estimates its costs based on feasibility and engineering studies and assessments using current restoration standards and techniques.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

3. SIGNIFICANT ACCOUNTING POLICIES - continued

l) Provision for environmental liabilities

Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a provision when it has a present obligation as a result of a past event to remediate the contaminated site, it is expected that future economic benefits will be given up to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

If the likelihood of the Utility's obligation to incur these costs is either not determinable or the amount of the obligation cannot be reliably estimated, the contingency is disclosed in the notes to the financial statements.

The Utility reviews its provision for environmental liabilities on an ongoing basis and any changes are recognized in net income for the current period.

m) Contributions in aid of construction

Certain property, plant and equipment additions are made with the assistance of cash contributions from customers or capital assistance from the Utility's Parent, the YG, or the Government of Canada. These contributions are deferred upon receipt and amortized to income on the same basis as the assets to which they relate.

n) Decommissioning fund

The decommissioning fund represents monies paid in advance by an industrial customer to decommission the spur line that connects its operation to the Utility's grid. Under a power purchase agreement, the customer has the financial responsibility for decommissioning expenses to be performed by the Utility on its behalf. Any amounts not required for decommissioning will be refunded to the customer. This money accrues interest at the rate equal to the three month Canadian Dealer Offered Rate ("CDOR").

o) Post-employment benefits and other comprehensive income

The Utility sponsors an employee defined benefit pension plan which provides benefits based on the length of service and average salaries for the five highest paid consecutive years of service. Effective January 1, 2011, the Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

For the defined benefit plan the cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Re-measurements of the net defined benefit liability, including actuarial gains and losses and return on plan assets, are recognized in other comprehensive income ("OCI") and are not reclassified to net income in a subsequent period. The Utility's policy is to immediately transfer actuarial gains and losses recognized in OCI to retained earnings. The expected return on plan assets is based on the fair value of these assets.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

3. SIGNIFICANT ACCOUNTING POLICIES - continued

o) Post-employment benefits and other comprehensive income - continued

Employees joining the Utility after January 1, 2002 are eligible for a defined contribution retirement plan and are not eligible to participate in the defined benefit pension plan. Contributions are required by both employees and the Utility to cover the current service cost of this defined contribution retirement plan. The Utility has no legal or constructive obligation to pay further contributions with respect to this plan. Consequently, contributions are recognized as an expense in the year when employees have rendered service and represents the obligation of the Utility.

p) New standards and interpretations not yet adopted

A number of new standards, and amendments to standards and interpretations, are not yet effective for the period ended December 31, 2016, and have not been applied in preparing these financial statements. There are three standards that management has identified as having a potential impact and is in the process of assessing, IFRS 15, *Revenue from Contracts with Customers*, IFRS 9, *Financial Instruments* which will replace IAS 39, *Financial Instruments* and IFRS 16, *Leases*.

i) On May 28, 2014, the IASB issued IFRS 15, *Revenue from Contracts with Customers*, which will replace IAS 18, *Revenue*. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard contains a single model that applies to contracts with customers and two approaches to recognising revenue: at a point in time or over time. The model features a contract based five step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Utility intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The Utility anticipates the adoption of IFRS 15 to have an impact on the financial statements, however, the extent of the anticipated impact is not known at this time.

ii) IFRS 9, *Financial Instruments*, which will replace IAS 39, *Financial Instruments: Recognition and Measurement* and IFRIC 9, *Reassessment of Embedded Derivatives*. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard is expected to impact the classification and measurement of financial assets, introduce changes to financial liabilities and includes new hedge accounting requirements. The Utility intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Utility is currently assessing the impact on its financial statements.

iii) IFRS 16, *Leases*, specifies how to recognize, measure, present and disclose leases. The standard provides a single lessee model, requiring lessees to recognize assets and liabilities for all leases unless the lease term is 12 months or less or the underlying asset has a low value. Lessors continue to classify leases as operating or finance, with IFRS 16's approach to lessor accounting substantially unchanged from its predecessor, IAS 17. This standard will become effective for annual periods beginning on or after January 1, 2019. The Utility is currently assessing the impact on its financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements requires the use of judgment in applying accounting policies and in making critical accounting estimates that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of any contingent assets and liabilities. These judgments and estimates are based on management's best knowledge of the relevant facts and circumstances, having regard to previous experience, but actual results may differ from the amounts included in the financial statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected. Information about such judgments and estimates is contained in the accounting policies and/or the notes to the financial statements, and the key areas are summarized below.

Areas of significant judgment and estimates made by management in preparing these financial statements include:

Impairment of long-lived assets - Notes 3g) and 7

An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Management continually monitors the Utility's operations and makes judgements and assessments about conditions and events in order to conclude whether possible impairment exists.

Asset retirement obligations – Notes 3k) and 22

In determining the present value of the obligation, the Utility must estimate the amount and timing of the future cash payments and then apply an appropriate risk-free interest rate. Any changes to the anticipated amounts or timing of future payments or risk-free interest rate can result in a change to the obligation.

Depreciation and amortization – Notes 3g), h), 7 and 8

Significant components of property, plant and equipment are depreciated over their estimated useful lives. Useful lives are determined based on current facts and past experience and the results of depreciation studies. While these useful life estimates are reviewed on a regular basis and depreciation calculations are revised accordingly, actual lives may differ from the estimates. As such, assets may continue in use after being fully depreciated, or may be retired or disposed of before being fully depreciated. The latter could result in additional depreciation expense in period of disposition.

Intangible assets - Notes 3h) and 8

In determining when to recognize costs as intangible assets, management makes judgments about when the criteria for recognition are met. Changes to management's judgments would affect the carrying amount of its intangible assets and amortization recognition.

Regulatory deferral account debit and credit balances - Notes 3j) and 9

The Utility accounts for its regulatory deferral accounts in accordance with IFRS 14 *Regulatory Deferral Accounts* and the decisions of the YUB. The decisions can be complex and require significant judgment in their interpretation.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS - continued

Post-employment benefits – Notes 3o) and 13

The Utility accrues for its obligations under defined benefit pension plans using actuarial valuation methods and other assumptions to estimate the projected benefit obligation and the associated expense related to the current period. The key assumptions utilized include the long-term rate of inflation, rates of future compensation, liability discount rates and the expected return on plan assets. The Utility consults with qualified actuaries when setting the assumptions used to estimate benefit obligations. Actual rates could vary significantly from the assumptions and estimates used.

Revenue – Note 16

The Utility estimates usage not yet billed at year end, which is included in revenues from sale of power. This accrual is based on an assessment of unbilled electricity supplied to customers between the date of the last meter reading and the year end. Management applies judgement to the measurement of the estimated consumption.

Provisions and Contingencies - Notes 3k), l), 21 and 22

Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*.

Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation. Key assumptions in measuring recognized provisions include the timing and amount of future payments and the discount rate applied in measuring the provision.

Where the Utility is defending certain lawsuits management must make judgements, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management will obtain the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

Financial Instruments - Notes 3f) and 23

The Utility enters into financial instrument arrangements which may require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, including whether those embedded derivatives meet the criteria to be separated from their host contract, in accordance with IAS 39, *Financial Instruments: Recognition and Measurement*. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable, and for embedded derivatives, whether the economic risks and characteristics are not closely related to the host contract and a separate instrument with the same terms would meet the definition of a derivative on a standalone basis.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

5. ACCOUNTS RECEIVABLE

	December 31 2016	December 31 2015
Wholesale energy sales	\$ 3,734	\$ 3,549
Retail energy sales	1,494	1,321
Due from related parties (Note 19)	112	850
Other	533	627
	\$ 5,873	\$ 6,347

At December 31, 2016, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	\$ 5,616	\$ 232	\$ 35	\$ 5,883
Allowance for doubtful accounts	-	-	(10)	(10)
	\$ 5,616	\$ 232	\$ 25	\$ 5,873

At December 31, 2015, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	\$ 5,680	\$ 192	\$ 485	\$ 6,357
Allowance for doubtful accounts	-	-	(10)	(10)
	\$ 5,680	\$ 192	\$ 475	\$ 6,347

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	December 31 2016	December 31 2015
Allowance for doubtful accounts at beginning of year	\$ (10)	\$ (10)
Amounts written off as uncollectable	-	-
Allowance for doubtful accounts at end of year	\$ (10)	\$ (10)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

6. INVENTORIES

	December 31 2016	December 31 2015
Materials and supplies	\$ 3,087	\$ 3,105
Diesel fuel	299	333
Liquefied natural gas	211	176
	\$ 3,597	\$ 3,614

The amount of inventory expensed during the year is \$1,169,000 (2015 - \$781,000) for fuel as disclosed in note 17 and \$86,000 (2015 - \$75,000) for materials and supplies.

7. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Generation	Transmission & Distribution	Land & Buildings	Transportation & Other	Construction Work-in Progress	Total
Cost:						
At December 31, 2014	230,695	144,586	13,939	3,234	47,951	440,405
Additions	-	-	-	-	22,255	22,255
Transfers	44,519	15,908	1,913	359	(62,699)	-
Disposals	(22)	-	-	(112)	-	(134)
At December 31, 2015	\$ 275,192	\$ 160,494	\$ 15,852	\$ 3,481	\$ 7,507	\$ 462,526
Additions	680	-	138	784	10,667	12,269
Transfers	3,100	2,834	882	-	(6,816)	-
Disposals	-	-	(635)	(311)	-	(946)
At December 31, 2016	\$ 278,972	\$ 163,328	\$ 16,237	\$ 3,954	\$ 11,358	\$ 473,849
Accumulated depreciation:						
At December 31, 2014	4,112	3,962	776	269	-	9,119
Depreciation*	4,903	4,248	812	290	-	10,253
Disposals	(1)	-	-	(39)	-	(40)
At December 31, 2015	\$ 9,014	\$ 8,210	\$ 1,588	\$ 520	\$ -	\$ 19,332
Depreciation	5,525	4,386	847	285	-	11,043
Disposals	-	-	(635)	(245)	-	(880)
At December 31, 2016	\$ 14,539	\$ 12,596	\$ 1,800	\$ 560	\$ -	\$ 29,495
Net book value:						
At December 31, 2015	\$ 266,178	\$ 152,284	\$ 14,264	\$ 2,961	\$ 7,507	\$ 443,194
At December 31, 2016	\$ 264,433	\$ 150,732	\$ 14,437	\$ 3,394	\$ 11,358	\$ 444,354

* Included in generation depreciation is the annual depreciation for overhauls of \$802,000 (2015 - \$778,000) which is recognized in regulatory account expenses in Note 17.

The AFUDC capitalized for 2016 was \$819,000 (2015 - \$714,000). The AFUDC rate estimate was 2.40% for 2016 (2015 - 2.46%).

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

8. INTANGIBLE ASSETS

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Software	Deferred Customer Service Costs	Financial Software	Aishihik Water Licensing	Thermal and Water Licensing	Total
Cost:						
At December 31, 2014	112	443	2,406	2,991	2,210	8,162
Additions	281	-	-	51	306	638
Acquisitions	69	-	-	-	-	69
Disposals	-	-	-	(10)	-	(10)
At December 31, 2015	\$ 462	\$ 443	\$ 2,406	3,032	\$ 2,516	\$ 8,859
Additions	66	-	-	955	297	1,318
Acquisitions	-	-	-	-	-	-
Disposals	(8)	-	-	-	-	(8)
At December 31, 2016	520	443	2,406	3,987	2,813	10,169
Accumulated amortization:						
At December 31, 2014	28	64	284	524	14	914
Amortization	33	64	284	524	58	963
Disposals	-	-	-	(10)	-	(10)
At December 31, 2015	\$ 61	\$ 128	\$ 568	\$ 1,038	\$ 72	\$ 1,867
Amortization	92	64	283	524	58	1,021
Disposals	-	-	-	-	-	-
At December 31, 2016	153	192	851	1,562	130	2,888
Net book value:						
At December 31, 2015	401	315	1,838	1,994	2,444	6,992
At December 31, 2016	367	251	1,555	2,425	2,683	7,281

The internally generated costs and externally purchased costs for Software and Financial Software are approximately 50% internal and 50% external at December 31, 2016 and December 31, 2015. All other categories are almost exclusively internally generated.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

9. REGULATORY ACCOUNTS

Regulatory deferral account debit balances

	Feasibility Studies (i)	IFRS Planning (ii)	Regulatory Costs (iii)	Vegetation Management (iv)	Dam Safety (v)	Uninsured Losses (vi)	Subtotal See next page
Cost:							
At December 31, 2014	20,794	566	4,144	917	332	300	27,053
Costs incurred	4,110	-	343	1,229	144	193	6,019
Regulatory provision	-	-	-	(502)	-	(226)	(728)
Disposals	(183)	-	-	-	(332)	-	(515)
Contribution received	(6,166)	-	(127)	-	-	-	(6,293)
At December 31, 2015	18,555	566	4,360	1,644	144	267	25,536
Costs incurred	4,869	-	695	1,074	4	1,018	7,660
Regulatory provision	-	-	-	(502)	-	(226)	(728)
Disposals	(2,051)	(566)	(794)	-	-	-	(3,411)
Contributions received	(825)	-	(1)	-	-	-	(826)
At December 31, 2016	20,548	-	4,260	2,216	148	1,059	28,231
Accumulated amortization:							
At December 31, 2014	3,342	339	1,099	-	308	-	5,088
Amortization	1,185	114	246	-	24	-	1,569
Disposals	(183)	-	-	-	(332)	-	(515)
At December 31, 2015	4,344	453	1,345	-	-	-	6,142
Amortization	25	113	248	-	-	-	386
Disposals	(2,051)	(566)	(794)	-	-	-	(3,411)
At December 31, 2016	2,318	-	799	-	-	-	3,117
Net book value:							
At December 31, 2015	14,211	113	3,015	1,644	144	267	19,394
At December 31, 2016	18,230	-	3,461	2,216	148	1,059	25,114
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2015	(3,241)	(114)	(30)	727	120	(33)	(2,571)
December 31, 2016	4,019	(113)	446	572	4	792	5,720
Remaining recovery years							
At December 31, 2015	5 to 10 years	1 year	10 to 45 years	Indeterminate	5 years	Indeterminate	-
At December 31, 2016	5 to 10 years	0 years	10 to 45 years	Indeterminate	4 years	Indeterminate	-
Absent rate regulation, net income would increase (decrease) by:							
December 31, 2015	3,241	114	30	(727)	(120)	33	2,571
December 31, 2016	(4,019)	113	(446)	(572)	(4)	(792)	(5,720)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

9. REGULATORY ACCOUNTS - continued

	Carry Forward	Deferred Overhauls (vii)	Fuel Price Adjustment (viii)	Deferred Gains And losses (ix)	Total
Cost:					
At December 31, 2014	27,053	943	19	-	28,015
Cost incurred	6,019	900	-	-	6,919
Regulatory provision	(728)	-	-	-	(728)
Disposals	(515)	-	-	-	(515)
Contributions received	(6,293)	-	(15)	-	(6,308)
At December 31, 2015	25,536	1,843	4	-	27,383
Cost incurred	7,660	925	-	-	8,585
Regulatory provision	(728)	-	-	-	(728)
Disposals	(3,411)	-	-	-	(3,411)
Contributions received	(826)	-	(6)	-	(832)
At December 31, 2016	28,231	2,768	(2)	-	30,997
Accumulated amortization:					
At December 31, 2014	5,088	-	-	-	5,088
Amortization	1,569	-	-	-	1,569
Disposals	(515)	-	-	-	(515)
At December 31, 2015	6,142	-	-	-	6,142
Amortization	386	-	-	-	386
Disposals	(3,411)	-	-	-	(3,411)
At December 31, 2016	3,117	-	-	-	3,117
Net book value:					
At December 31, 2015	19,394	1,843	4	-	21,241
At December 31, 2016	25,114	2,768	(2)	-	27,880
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income):					
December 31, 2015	(2,571)	900	(15)	-	(1,686)
December 31, 2016	5,720	925	(6)	-	6,639
Remaining recovery years					
At December 31, 2015		Indeterminate	1 year		
At December 31, 2016		Indeterminate	1 year		
Absent rate regulation, Net Income would increase (decrease) by:					
December 31, 2015	2,571	(900)	15	-	1,686
December 31, 2016	(5,720)	(925)	6	-	(6,639)

(a) Regulatory deferral account debit balances

(i) Feasibility studies and infrastructure planning

The Utility undertakes certain studies to determine the feasibility of a range of projects and infrastructure proposals. While in progress, the costs of these studies are deferred within this account. Once the study is completed, the costs are amortized over a prescribed number of years ranging between five and ten years under regulatory reporting. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(ii) IFRS planning

These deferred costs are associated with the conversion from previous GAAP to IFRS and are amortized over a term of five years. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

9. REGULATORY ACCOUNTS - continued

(iii) Regulatory costs

These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings but also include resource plans, hearing costs from before 2012 and demand side management costs (consumer energy conservation program). The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(iv) Vegetation management

These deferred costs are annual brushing costs in excess of the maximum annual amount approved by the YUB. Amortization of these costs has not yet been approved. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(v) Dam safety review

The Utility has a program of conducting safety reviews of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are being amortized over five years as approved by the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(vi) Uninsured losses

The YUB has approved the use of a deferral account for uninsured damages and injuries as a means of self-insurance. The account is maintained through an annual provision approved by the YUB and collected through customer rates. Variances between the approved annual provision and actual costs incurred are deferred until the following GRA or until a specific application is made to the YUB requesting recovery from or refund to customers. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(vii) Deferred overhauls

Overhauls represent costs incurred to overhaul engines that are used in operations and these overhauls are recorded as property, plant and equipment. The Utility was directed by YUB Order 2013-01 to defer all overhaul costs incurred after 2011 until the Utility comes before the YUB for a prudence review and the costs are approved to be depreciated. IFRS requires these completed overhauls to be considered in service and they should be depreciated through net income. In addition, IFRS also requires that AFUDC would cease when the overhaul is substantially ready for its intended purpose. As a result the AFUDC capitalized on these completed overhauls of \$119,000 (2015 - \$122,000) and the associated depreciation on these overhauls of \$802,000 (2015 - \$778,000) are shown as a regulatory deferral account debit balance.

(viii) Fuel price adjustment

OIC 1995/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the YUB approved rates is deferred and recovered from or refunded to customers in a future period. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(ix) Deferred gains and losses

Deferred gains and losses represent amounts from disposals of property plant and equipment. There are no deferred gains or losses during any of the reporting years.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

9. REGULATORY ACCOUNTS - continued

Regulatory deferral account credit balances

	Deferred Insurance Proceeds (i)	Hearing reserve (ii)	Diesel Contingency Fund (iii)	Future removal and site Restoration (iv)	Total
Cost:					
At December 31, 2014	11,602	224	9,627	4,671	26,124
Cost incurred	-	(213)	-	(304)	(517)
Regulatory provision	-	550	-	-	550
Cash received	-	-	2,027	-	2,027
Cash refunded	-	-	(759)	-	(759)
At December 31, 2015	11,602	561	10,895	4,367	27,425
Cost incurred	-	(138)	-	(8)	(146)
Regulatory provision	-	550	-	-	550
Cash received	-	-	1,054	-	1,054
Cash refunded	-	-	(2,464)	-	(2,464)
At December 31, 2016	11,602	973	9,485	4,359	26,419
Accumulated amortization:					
At December 31, 2014	5,849	-	-	-	5,849
Amortization	262	-	-	-	262
Disposals	-	-	-	-	-
At December 31, 2015	6,111	-	-	-	6,111
Amortization	263	-	-	-	263
Disposals	-	-	-	-	-
At December 31, 2016	6,374	-	-	-	6,374
Net book value					
At December 31, 2015	5,491	561	10,895	4,367	21,314
At December 31, 2016	5,228	973	9,485	4,359	20,045
Net (increase) decrease in regulatory deferral account credit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the statement of operations and other comprehensive income):					
December 31, 2015	262	(337)	(1,268)	304	(1,039)
December 31, 2016	263	(412)	1,410	8	1,269
Remaining recovery years					
At December 31, 2015	21 years	Indeterminate	Indeterminate	Indeterminate	
At December 31, 2016	20 years	Indeterminate	Indeterminate	Indeterminate	
Absent rate regulation, net income would increase (decrease) by:					
December 31, 2015	(262)	337	1,268	(304)	1,039
December 31, 2016	(263)	412	(1,410)	(8)	(1,269)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

9. REGULATORY ACCOUNTS - continued

(b) Regulatory deferral account credit balances

(i) Deferred insurance proceeds

The deferred insurance proceeds represents a gain on fire insurance proceeds related to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to YUB Order 2000-3, is being amortized to income at the same rate as depreciation of the related replacement assets. In the absence of rate regulation, IFRS would have required the gain to have been fully recognized as income in the year received.

(ii) Hearing reserve

Pursuant to YUB Order 2013-01, the Utility has established a deferral account for future regulatory hearing costs. In accordance with the order the Utility recognized a provision of \$550,000 of hearing costs each year. Actual hearing costs will be applied to this regulatory deferral account. Variances between the annual provision and actual costs are deferred until the following GRA or until a specific application is made to the YUB requesting recovery or a refund to customers. In the absence of rate regulation, IFRS would require hearing costs to be expensed as incurred.

(iii) Diesel Contingency Fund and Energy Reconciliation Adjustment

The Diesel Contingency Fund ("DCF") was established by YUB Order 1996-6. The DCF is used to reimburse the Utility for costs associated with diesel generation required when there is a diesel cost variance due solely to water-related hydro and wind generation variances from YUB approved GRA forecasts.

The DCF attracts interest based upon short/intermediate term bond rates. Any negative balance attracts interest at the lowest short-term bond rates available to the Utility through its line of credit. The Utility is required to file quarterly reports with the YUB on the DCF's activity.

As part of the 2012/13 GRA, the Utility filed for changes to the DCF and Energy Reconciliation Adjustment ("ERA") provisions of the Wholesale Primary Rate Schedule. The YUB deferred a decision on these two issues pending further consultation with affected utilities and a separate proceeding to review the impacts of proposed changes.

In January 2014, the Utility filed an application to revise the DCF and ERA with the YUB. A decision was delivered February 6, 2015. In accordance with YUB Order 2015-01, the Utility defers recognition of the additional amounts collected from rate payers when the cost of diesel consumed in the period is less than the long-term average diesel requirements estimated for the actual annual generation load. These deferred revenues are recognized as revenue in the period when the cost of diesel fuel incurred for the period is greater than the long-term average diesel requirements and the reason for the shortfall is a shortage of water in the hydro system. The YUB has set a cap of +/- \$8 million for the DCF. If the balance falls outside of this range, the Utility is to make an application to the YUB requesting recovery or a refund to customers. In accordance with YUB Order 2015-06, the Utility is providing a refund to the customers of 0.68 cents/kWh effective September 1, 2015.

In the 2012/13 GRA, the Utility applied to reactivate the ERA provision in the Wholesale Primary Rate Schedule. In YUB Order 2015-06, the YUB rejected the proposal and as a result the Utility eliminated the ERA balances in accounts receivable and accounts payable for the years ended December 31, 2015 and 2014.

In the absence of rate regulation, IFRS would require any amounts earned or incurred related to the DCF to be included in the Utility's net income in the year incurred.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

9. REGULATORY ACCOUNTS - continued

(iv) Future removal and site restoration costs

The Utility maintains a regulatory provision for future removal and site restoration related to property plant and equipment, which is incremental to that required to be recognized as an asset retirement provision under IAS 37. The reserve has been established through amortization rates approved by the YUB. The amortization rates supporting the provision are based upon depreciation studies conducted periodically by the Utility. As a result of the YUB Order 2005-12, effective January 1, 2005, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of \$5,757,000. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches \$2,000,000.

Costs of dismantling capital assets, including site remediation, will be applied to this regulatory deferral account credit balance if they do not otherwise relate to an asset retirement provision. The period over which the provision will be reduced is dependent on the timing of future costs of demolishing, dismantling, tearing down, site restoration or otherwise disposing of the asset net of actual recoveries, and is therefore indeterminate. In the absence of rate regulation, IFRS would require these costs to be expensed or included in the gain or loss on disposal of the related property, plant and equipment, as applicable.

(c) Regulatory account expenses

Regulatory account expenses represent costs incurred related to regulatory account debit balances of \$8,585,000 (2015 - \$6,919,000) and regulatory account credit balances of \$146,000 (2015 - \$517,000). Total regulatory expenses were \$8,731,000 (2015 - \$7,436,000) and all these amounts were paid during the year.

(d) Net movement in regulatory deferral account balances related to net income

Net movement in regulatory deferral account balances related to net income is \$7,908,000 (2015 – \$(2,725,000)) represents the adjustment to the net income for the year before net movement in regulatory deferral account balances for the effects of rate regulation in accordance with IFRS 14. The net movement figure of \$7,908,000 is comprised of higher net income of \$6,639,000 and \$1,269,000 for both regulatory account debit balances and regulatory account credit balances for rate regulation compared to the amounts that would be recorded under IFRS. The net movement figure of \$(2,725,000) for 2015 is comprised of lower net income of \$(1,686,000) and \$(1,039,000) for both regulatory account debit balances and regulatory account credit balances for rate regulation compared to the amounts that would be recorded under IFRS.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31 2016	December 31 2015
Trade payables	\$ 7,138	\$ 5,763
Employee compensation	989	885
Due to related parties (Note 19)	199	433
Other	209	229
	\$ 8,535	\$ 7,310

11. CONSTRUCTION FINANCING

	December 31 2016	December 31 2015
Construction financing due December 31, 2016, bearing interest at 1.03% approved to a maximum of \$25 million	\$ -	\$ 14,880
Construction financing, due December 31, 2016 bearing interest at 1.03% approved to a maximum of \$8.4 million	-	8,400
Construction financing, due December 31, 2017 bearing interest at 1.33% approved to a maximum of \$8.4 million	8,400	-
Construction financing, due December 31, 2017 bearing interest at 1.40% approved to a maximum of \$14 million	13,985	-
	\$ 22,385	\$ 23,280

Construction financing balances are monies advanced from the Parent to assist in the development of the Utility's infrastructure. Interest is payable annually at December 31 and at the maturity date.

During the year the Utility did not make any principal repayments. The Utility borrowed an additional \$8,400,000 and refinanced the amount of \$23,280,000 which was due December 31, 2016 as \$13,985,000 in construction financing and \$9,295,000 as long-term debt.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

12. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	December 31 2016	December 31 2015
Yukon Development Corporation		
\$92,458,473 term note bearing interest at 2.40% repayable in annual installments of \$3,683,800 principal, plus accrued interest with the balance of \$77,726,473 due December 31, 2019	\$ 85,091	\$ 88,775
\$21,900,000 flexible term note bearing interest up to 5.46% repayable in annual installments of \$336,923 principal, plus accrued interest with the balance of \$8,423,078 due December 31, 2051 (i)	20,215	20,552
\$5,505,000 term note bearing interest at 2.40% interest only payable annually, due December 31, 2039	5,505	5,505
\$20,984,404 term note bearing interest at 2.21% repayable in annual installments of \$839,376 principal, plus accrued interest with the balance due December 31, 2040	20,145	20,984
\$12,136,000 term note bearing interest at 2.10% interest only payable annually, due December 31, 2041 (ii)	12,136	-
TD Bank		
\$12,400,000 term note bearing interest at 4.02% payable in monthly installments of \$94,406 interest and principal, with the balance due September 30, 2016. The note is guaranteed by the Yukon Government.	-	837
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptances amounts from a variable interest rate based on the Bankers' Acceptances rates to a fixed rate of 2.69% per annum. Payable in monthly installments of \$50,407 interest and principal with the balance due on December 28, 2022 (iii)	9,697	10,036
Carmacks Stewart First Nation Liability		
Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non-interest bearing, repayable in varying installments, due in 2028	220	251
	153,009	146,940
Less current portion	5,238	6,066
	\$ 147,771	\$ 140,874

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

12. LONG-TERM DEBT - continued

(i) **\$21,900,000 Flexible Term Note**

The terms of the flexible term note provide for a maximum amount of interest payable within a calendar year, calculated based on the actual grid generation on the electrical grid system connected with the Mayo Hydro Enhancement Project. The amount of interest payable as a result of the interest rate exceeding the maximum interest payable will abate forever. The actual interest rate on this flexible note was 0.81% (2015 - 0.61%).

(ii) **Debt Refinancing**

On December 31, 2016, the Utility entered into an agreement with YDC to convert \$9,295,000 of existing construction financing with YDC into long-term debt (Notes 11 and 12) and borrow \$2,841,000 declared as a dividend to YDC at year end to maintain its capital structure (Note 25).

(iii) **TD Bank Loan and Interest Rate Swap**

On December 28, 2012, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures December 28, 2022.

Long-term debt repayment

Scheduled repayments for all long-term debt are as follows:

2017	\$ 5,245
2018	5,255
2019	79,284
2020	1,571
2021	1,564
Thereafter	60,091
	\$ 153,010

Fair value

The fair value of long-term debt at December 31, 2016 is \$154 million (2015 - \$149 million). The fair value for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

13. POST-EMPLOYMENT BENEFITS

Characteristics of benefit plans

The Utility sponsors a defined benefit pension plan for employees joining the Utility before January 1, 2002 and a defined benefit pension plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the employee defined benefit pension plan. The Utility makes contributions to a Registered Retirement Savings Plan ("RRSP") on behalf of these employees and employees hired before January 1, 2002 who belonged to the employee defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution plan. The costs recognized for the period are equal to the Utility's contribution to the plan. During 2016, these were \$448,000 (2015 - \$446,000).

The employee defined benefit pension plan and the defined benefit pension plan for a former executive are regulated by the Office of the Superintendent of Financial Institutions (OSFI) through the *Pension Benefits Standards Act* and regulations. This Act and accompanying regulations impose, among other things, minimum funding requirements.

These minimum funding requirements require the Utility make special payments as prescribed by the OSFI to repay any unfunded liability or deficit that may exist. For the employee defined benefit pension plan the Utility is required to pay \$225,300 as a minimum annual payment in each of the next 12 years (2015 - \$323,700 in each of the next 12 years).

A committee of the Utility's Board of Directors oversees these plans and is responsible for the investment policy with regard to the assets of these funds.

Risks associated with defined benefit plans

The defined benefit pension plans expose the Utility to risk such as investment risk and actuarial risk. Investment risk is the risk that the assets invested will be insufficient to meet expected benefits. Actuarial risk is the risk that benefits paid will be more than expected. There are no particular unusual, entity-specific or plan-specific risks or any significant concentration of risk.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

13. POST-EMPLOYMENT BENEFITS - continued

Net defined benefit liability

	December 31 2016	December 31 2015
Present value of benefit obligations		
Balance, beginning of year	\$ 20,793	\$ 20,690
Employee Contributions	84	89
Current service cost	493	544
Interest cost	868	847
Benefits paid	(458)	(397)
Actuarial losses (gains) on experience	539	(657)
Actuarial losses (gains) on financial assumptions	661	(323)
Balance, end of year	\$ 22,980	\$ 20,793
Fair value of plan assets		
Balance, beginning of year	15,357	14,672
Interest income on plan assets	638	599
Gains (losses) on plan assets	716	(468)
Employee contributions	84	89
Employer contributions	781	905
Benefits paid	(421)	(360)
Administrative costs	(42)	(80)
Balance, end of year	17,113	15,357
Net defined benefit liability	\$ 5,867	\$ 5,436

Components of benefit plan cost:

	December 31 2016	December 31 2015
Current service cost	493	544
Interest cost	868	847
Interest income on plan asset	(638)	(599)
Administrative costs	42	80
Defined benefit expense in Statement of Operations	765	872
Defined contribution expense	448	446
Total benefit expense in Statement of Operations	\$ 1,213	\$ 1,318

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

13. POST-EMPLOYMENT BENEFITS - continued

Actuarial losses (gains) on obligation	1,200	(980)
(Gains) losses on plan assets	(717)	468
Total re-measurements included in Other Comprehensive Income	483	(512)
Total benefit costs recognized in Statement of Operations and Other Comprehensive Income	1,696	806

Distribution of plan assets of defined benefit pension plans

The fair value of the defined benefit pension plans' assets are based on market values as reported by the defined benefit pension plans' custodians as at each applicable Statement of Financial Position date. The distribution of assets by major asset class is as follows:

	<u>December 31, 2016</u>	<u>December 31, 2015</u>
Equities	54.9%	52.4%
Fixed income securities	35.9%	36.8%
Real estate	9.2%	10.8%

Significant assumptions:

	<u>December 31, 2016</u>	<u>December 31, 2015</u>
Discount rate - accrued benefit obligation	3.90 - 4.00%	4.10 - 4.50%
Assumed rate of salary escalation	2.80 - 3.50%	3.00 - 3.50%
Pension growth	2.00 - 2.50%	2.00 - 2.50%

Sensitivity analysis of the defined benefit pension plans:

The sensitivities of each key assumptions used in measuring accrued benefit obligations at each Statement of Financial Position date have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously. The sensitivity analysis has been determined based on reasonably possible changes of the respective assumptions occurring at the end of the reporting period. The mortality assumptions are based on the 2014 Canadian Pensioner Mortality Private Table projected with full generational mortality improvements using scale B.

Assumptions and sensitivity as at December 31, 2016

Assumption	+1%	-1%	+1%	-1%
Discount rate	-14.1%	17.9%	\$ (3,241)	\$ 4,129
Salary growth	2.5%	-2.4%	550	(521)
Pension growth	14.2%	-11.7%	3,071	(2,537)
Life expectancy (1 year movement)	2.4%	-2.4%	555	(559)

Assumptions and sensitivity as at December 31, 2015

Assumption	+1%	-1%	+1%	-1%
Discount rate	-14.6%	18.6%	\$ (2,839)	\$ 3,617
Salary growth	3.2%	-3.0%	616	(579)
Pension growth	13.7%	-11.4%	2,678	(2,220)
Life expectancy (1 year movement)	2.3%	-2.3%	446	(450)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

13. POST-EMPLOYMENT BENEFITS - continued

The sensitivity analysis presented above may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Furthermore, in presenting the above sensitivity analysis, the present value of the defined benefit obligation has been calculated using the projected unit credit method at the end of the reporting period, which is the same that is applied in calculating the defined benefit obligation liability recognized in the Statement of Financial Position.

The Utility pays the balance of the cost of the Plan over the employee contributions, as determined by the actuary. Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings (YMPE) plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. Employees can make additional contributions to purchase ancillary benefits. Members choose the ancillary benefit on termination of service or on retirement.

The average duration of the benefit obligation is 16.0 years (2015 - 16.6 years). The Utility expects to make payments of \$706,000 (2015 - \$871,000) to the defined benefit plans during the next financial year.

14. CONTRIBUTIONS IN AID OF CONSTRUCTION

	Government of Canada	Parent since 1998	Customer since 1998	Yukon Government since 1998	Pre-1998 contributions	Total
Cost:						
At December 31, 2014	71,000	73,545	24,001	10,879	1,739	181,164
Additions	-	18,265	578	161	-	19,004
At December 31, 2015	71,000	91,810	24,579	11,040	1,739	200,168
Additions	-	-	274	58	-	332
At December 31, 2016	71,000	91,810	24,853	11,098	1,739	200,500
Accumulated amortization:						
At December 31, 2014	3,048	6,694	7,588	1,425	1,249	20,004
Amortization	991	1,217	1,173	200	43	3,624
At December 31, 2015	4,039	7,911	8,761	1,625	1,292	23,628
Amortization	990	1,680	1,179	209	44	4,102
At December 31, 2016	5,029	9,591	9,940	1,834	1,336	27,730
Net book value:						
At December 31, 2015	66,961	83,899	15,818	9,415	447	176,540
At December 31, 2016	65,971	82,219	14,913	9,264	403	172,770

The sources of contributions received prior to 1998 were not recorded separately.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

15. DECOMMISSIONING FUND

	December 31 2016	December 31 2015
Opening balance	\$ 2,612	\$ 2,586
Interest	24	26
Closing balance	\$ 2,636	\$ 2,612

16. SALES OF POWER

	2016	2015
Wholesale	\$ 28,641	\$ 29,794
Industrial	4,506	4,230
General service	4,359	4,265
Residential	2,040	2,015
Secondary sales	371	544
Sentinel and street lights	96	100
	\$ 40,013	\$ 40,948

17. OPERATIONS AND MAINTENANCE EXPENSES

	2016	2015
Regulatory account expenses (Note 9 (c))	\$ 8,731	\$ 7,436
Wages and benefits	5,955	5,553
Contractors	1,692	1,826
Materials and consumables	1,173	1,143
Fuel	1,168	781
Travel	311	341
Rent	234	234
Communication	58	62
	\$ 19,322	\$ 17,376

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

18. ADMINISTRATION EXPENSES

	2016	2015
Wages and benefits	\$ 5,737	\$ 5,516
Materials, consumables and general	2,273	849
Insurance and taxes	1,812	1,593
External labour	1,189	1,094
Licences and fees	658	614
Travel	171	170
Board fees	83	55
	\$ 11,923	\$ 9,891

19. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all YG departments, agencies and Territorial Corporations. Transactions are entered into in the normal course of operations with these entities. All sales transactions are recorded at the rates approved by the YUB.

Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers. These revenues are included in sales of power on the Statement of Operations and Other Comprehensive Income.

The following table summarizes the Utility's related party transactions for the year:

	2016	2015
Revenue		
Sales of service to YDC	\$ 6	\$ 14
Program cost reimbursement from YG	-	127
Rate subsidy received from YDC	299	274
Funding from YDC	825	6,135
Operating expenses		
Interest expense on borrowings from YDC	\$ 3,220	\$ 2,964
Dividend to YDC	\$ 2,841	\$ -
Other receipts		
Construction financing from YDC	8,400	11,200
Long-term debt from YDC	-	20,984
Other payments		
Repayment of long-term debt from YDC	\$ 4,860	\$ 4,021
Repayment of construction financing from YDC	-	8,400

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

19. RELATED PARTY TRANSACTIONS - continued

Other related party transactions and balances are as disclosed elsewhere in these financial statements (Notes 11 and 12).

Funding from YDC of \$825,000 is for feasibility studies for the Stewart Keno Transmission Line.

At the end of the year, the amounts receivable from and due to related parties are as follows:

	December 31 2016	December 31 2015
YDC		
Accounts receivable	\$ 28	\$ 27
Accounts payable	167	128
Construction financing	22,385	23,280
Current portion of long-term debt	4,860	4,860
Long-term debt	138,233	130,957
YG		
Accounts receivable	\$ 62	\$ 823
Accounts payable	32	301

These balances are non-interest bearing and payable on demand except for construction financing and long-term debt.

Transactions with Key Management Personnel

The Utility's key management personnel include members of the senior management team and the Board of Directors, a total of 18 individuals (2015 - 18 individuals). Key management personnel compensation is as follows:

Year ended December 31	2016	2015
Short-term employee benefits	\$ 1,537	\$ 1,606
Post-employment benefits	59	55
Retirement benefits	-	18
	\$ 1,596	\$ 1,679

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

20. COMMITMENTS

Aishihik water licence

The Yukon Water Board issued a water use licence in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this licence commits the Utility to meet a number of future requirements including annual fish monitoring programs.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2019. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

Contractual obligations

The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31, 2016 as the product or service had not been provided. The total commitments at year end are \$1,754,000 (2015 - \$5,712,000).

21. CONTINGENCIES

Aishihik Third Turbine Project

This project was commissioned into service in December 2011. On March 2, 2012, the general contractor filed a claim with the Supreme Court of Yukon for \$4,000,000 plus interest and costs alleging the Utility has not paid for work performed. During 2016, the judge awarded the plaintiff \$1,682,000 of which \$1,308,000 had already been accrued for in the financial statements. The Utility is also required to reimburse the plaintiff for its legal costs and interest. The Utility has recognized an estimate for this amount as a liability in the Statement of Financial Position. The Utility has appealed the decision. The outcome of the appeal is not determinable at this time and no estimate of appeal settlement has been recognized in the financial statements.

Asset Retirement Obligations

The Utility has not recognized a provision for the closure and restoration obligations for certain generation, transmission and distribution assets which the Utility anticipates maintaining and operating these assets for an indefinite period, making the date of retirement of these assets indeterminate. These significant uncertainties around the timing of any potential future cash outflows are such that a reliable estimate of the liability is not possible at this time. A provision will be recognized when the timing of the retirement of these assets can be reasonably estimated.

22. PROVISION FOR ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations.

The Utility has conducted environmental site assessments at all its diesel plant sites. At sites where environmental contamination was found and a legal obligation to remediate the site existed, the Utility has conducted a full remediation. As at December 31, 2016 no new provisions for environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility will continue to use its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis. The Utility does not have a provision for environmental liabilities as there is no present obligation to remediate.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2016, the Utility's financial instruments included cash, accounts receivable, accounts payable and accrued liabilities, construction financing, long-term debt and interest rate swaps. The fair value of cash, accounts receivable, accounts payable and accrued liabilities and construction financing approximate their carrying value due to the immediate or short-term maturity of these financial instruments.

The long-term debt is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term debt is estimated by discounting the future cash flows using current rates for debt instruments subject to similar risks and maturities as disclosed in Note 12.

Interest rate swaps are financial contracts that derive their value from changes in an underlying variable. The Utility's interest rate swaps are classified as held for trading and are recognized at their fair value on the date the contract has been entered into. Any subsequent unrealized and realized gains and losses are reported in net income during the period in which the fair value movement occurred. The fair value of the interest rate swaps is estimated using standard market valuation techniques and is provided to the Utility by the financial institution that is the counterparty to the transactions.

The Utility did not engage in any other hedging transactions.

Interest rate risk

Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility's future cash flows are not exposed to significant interest rate risk due to its long-term debt having fixed interest rates, with the exception of the Bankers' Acceptances from the TD Bank. The Bankers' Acceptances have had the variable rate converted to a fixed rate using an interest rate swap to eliminate the interest rate risk.

As at December 31, 2016, the Utility had an interest rate swap agreement in place with a notional principal amount of \$9.7 million (2015 - \$10.0 million). The agreement effectively changes the Utility's interest rate exposure on this notional amount from a floating rate to a fixed rate of 2.69%.

The fair value of the interest rate swap agreement on December 31, 2016 was a liability of \$409,000 (2015 - liability of \$553,000). The increase in the fair value in 2016 of \$144,000 (2015 - decrease of \$340,000) is recognized on the Statement of Operations and Other Comprehensive Income as an unrealized gain or loss. A 100 basis point increase or decrease in the interest rate assumption would have resulted in an increase/decrease in the interest rate swap agreements fair value of \$498,000 (2015 - \$593,000).

The Utility has access to a \$10 million line of credit. The account accrues interest on withdrawals at prime rate minus 0.75% per annum. By agreement the financial institution has a legally enforceable right to set off the outstanding balance under the line of credit by cash balances in other accounts with the same bank. The amount outstanding on the line of credit balance at year end was \$2.5 million (2015 - \$1.3 million). The Utility has cash balances with the same financial institution of \$2.8 million (2015 - \$2.8 million). Due to the short-term nature of the amount drawn on the line of credit and the Utility's cash balances with the same financial institution, the interest rate risk is minimal.

Credit risk

Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

The following table illustrates the maximum credit exposure to the Utility if all counterparties defaulted:

	December 31 2016	December 31 2015
Cash	\$ 551	\$ 1,672
Accounts receivable	5,873	6,347
	\$ 6,424	\$ 8,019

Credit risk on cash is considered minimal as the Utility's cash deposits are held by a Canadian Schedule 1 Chartered bank.

Credit risk on accounts receivable is considered minimal as the Utility has experienced insignificant bad debt in prior years. In addition, its primary customer is a rate regulated utility that purchases power from the Utility for resale and as such these receivables are considered fully collectible. Included in the accounts receivable past due but not impaired at December 31, 2016 are \$257,000 (2015 - \$667,000) which management believes will be received in full.

Liquidity risk

Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility manages liquidity risk through regular monitoring of cash and currency requirements by preparing cash flow forecasts to identify financing requirements. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

The Utility's largest current liability is current portion long-term debt which is predominantly due to the parent, and the Utility has successfully renegotiated this debt in prior years. In addition, rate regulation assists the Utility with liquidity management by providing consistent revenues and a consistent debt to equity ratio.

Fair values

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2016:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	\$409	-	\$409
Long-term debt	-	-	\$154,000	\$154,000

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

December 31 2016

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2015:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	\$553	-	\$553
Long-term debt	-	-	\$149,000	\$149,000

24. CAPITAL MANAGEMENT

The Utility's capital is its shareholder's equity which is comprised of share capital, contributed surplus and retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year. Short term debt related to assets under construction at the Statement of Financial Position date is excluded from the calculation of total debt, as the assets are similarly excluded from the determination of rate base. In addition the provision for decommissioning of the Minto Mine spur line has been added (Note 15). Total capitalization is calculated as total debt plus total shareholder's equity as shown on the Statement of Financial Position. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

The Utility has a policy which defines its capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of Canadian dollars)

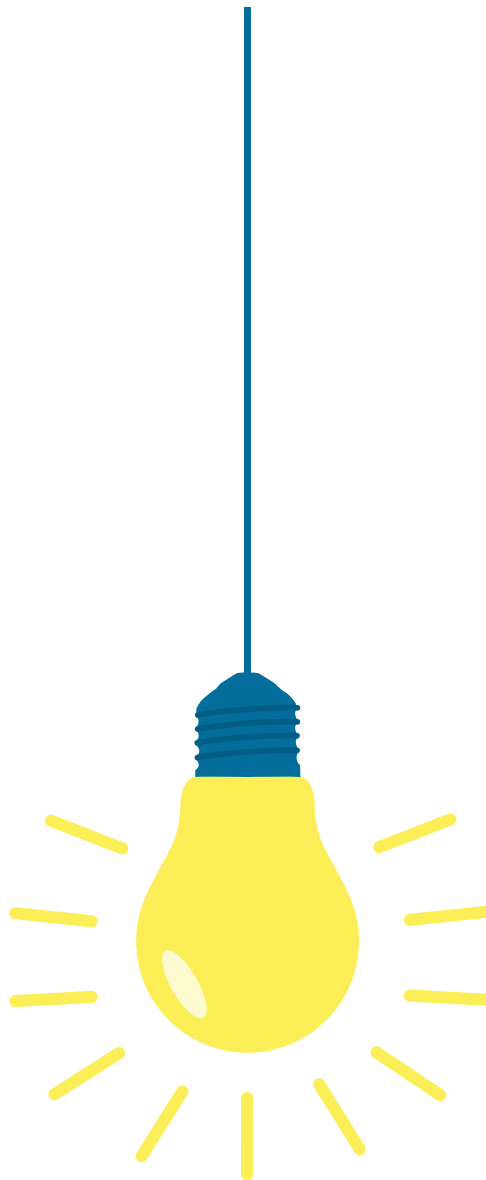
December 31 2016

24. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility's total debt to total capitalization position:

	December 31	
	2016	2015
Long-term debt due within one year	\$ 5,238	\$ 6,066
Long-term debt	147,771	140,874
Total debt	153,009	146,940
Add provision for decommissioning of industrial customer spur line	2,636	2,612
Total debt to include in the calculation	\$ 155,645	\$ 149,552
Share capital	\$ 39,000	\$ 39,000
Contributed surplus	14,600	14,600
Retained earnings	51,034	46,303
Total shareholder's equity	104,634	99,903
Total capitalization	\$ 260,279	\$ 249,455
Total debt to total capitalization	60 %	60 %

There were no changes in the Utility's approach to capital management during the period.



**YUKON
ENERGY**

April 6, 2018

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Page A-43

1 **TOPIC:**

2
3 **REFERENCE: June 22, 2017 Application, page 1**

4
5 *YEC states "Pursuant to the Order in Council (OIC) 2014/23*
6 *direction, the Board must ensure until the end of 2018 that rate*
7 *adjustments for retail customers and major industrial customers*
8 *apply equally, when measured as percentages, to all classes of*
9 *retail customers and to the class of major industrial customers.*
10 *Consequently, for both 2017 and 2018, all proposed rate*
11 *adjustments for retail customers and industrial customers apply*
12 *equally, as percentages".*

13
14 **REFERENCE: December 11, 2017 IR Responses, VGC PPA, UCG-YEC-1-13(c)**

15
16 *"YEC is not specifically prohibited from conducting a fully allocated*
17 *cost of service (COS) analysis, subject to securing from AEY the*
18 *information needed for completing a consolidated COS for all*
19 *Yukon including both YEC and AEY facilities and customers."*
20

21 **PREAMBLE:**

22
23 **QUESTION:**

- 24
25 a) Please confirm that there is no cost of service analysis underlying current wholesale
26 rates charged by YEC.
27
28 b) Please confirm that the revenue-to-cost ratio related to YEC's wholesale rate class
29 is not currently known.
30

31 **ANSWER:**

32
33 **(a) and (b)**

34
35 Cost of service analysis, with related revenue-to-cost ratios for each customer class, is
36 done for firm retail and industrial customer class rates, based on a consolidated YEC/AEY
37 test year approved revenue requirement. No cost of service analysis or revenue-to-cost

- 1 ratio has ever been done, or would be appropriate to do, on the wholesale rate charged
- 2 to AEY by YEC.

**Yukon Utilities Board
(YUB)**

1 **TOPIC:** DCF

2
3 **REFERENCE:** Appendix A to Board Order 2015-01, PDF pages 6 and PDF
4 page 14

5
6 **QUOTE:** The difference in cost between forecast diesel and actual diesel
7 generation in any year at any given level of grid generation reflects
8 only the variance in water availability (hydro generation) relative to
9 the forecast, and this difference is what goes into or comes out of the
10 DCF. Funds are held in the DCF to protect ratepayers against
11 adverse and material rate impacts at such time as drought or low
12 water conditions act to severely reduce hydro generation and thereby
13 require increased diesel generation on the grid. (Footnote omitted,
14 emphasis added)(Page 6 of 30)

15 ...

16 ... the Board accepts the DCF as proposed by YEC because it is a
17 fund for customers to smooth rate impacts for those occasions when
18 hydro generation is less than LTA or to build up the fund when hydro
19 generation is greater than LTA. (Footnote omitted, emphasis
20 added)(Page 14 of 30)

21
22 **PREAMBLE:** Whether or not changes should be made to the DCF

23
24 **QUESTION:**

25
26 a) Please confirm that the DCF, as it currently exists, stabilizes utility costs of
27 diesel (now thermal) due to fluctuations in generation related to higher or lower
28 than average long term hydro generation due to water availability.

29
30 b) If part (a) is not confirmed, please explain.

31
32 c) For the DCF, as it currently exists, is the implementation or operation of the
33 DCF different today from that described in the above-noted quotes from
34 Appendix A to Board Order 2015-01? Please explain.

35
36 d) Should ratepayers or YEC pay for variances from forecast thermal generation
37 fuel volumes? Please explain. Is this a common practice in Canadian

1 jurisdictions? Please explain.

2

3 e) For isolated communities, please explain whether ratepayers or YEC pay for
4 variances from forecast thermal generation fuel volumes.

5

6 f) For the DCF, as it currently exists, are ratepayers at risk for all thermal
7 generation fuel volume variances (including fuel volume variances not related
8 to water conditions)? Please explain.

9

10 g) If the Board determined that ratepayers should not assume 100% of the risk
11 for variances from thermal generation volume forecasts, what impact would
12 that have on YEC?

13

14 h) If YEC assumed the risk for thermal generation volume variances above or below
15 forecast up to a certain threshold, for example 10%, how would that impact YEC?
16 (For clarity, any variances above or below the threshold would be borne by
17 ratepayers but any variance within the bounds of the thresholds would be borne
18 by YEC). Please indicate what YEC would consider an appropriate threshold and
19 why.

20

21 i) What are YEC's views if, instead of the DCF, a rider set at a determined level of
22 cents/MW.h of energy sold was established to create a fund or deferral account to
23 cover variances for extreme water conditions (flood or drought)? What impact
24 would such a rider have on YEC?

25

26 **ANSWER:**

27

28 **(a) and (b)**

29

30 Confirmed.

31

32 **(c)**

33

34 The above-noted quotes reference high-level and fundamental principles of the DCF.
35 These principles have been retained in the DCF as it currently exists and as it is proposed
36 in the 2017/18 GRA, and in this respect the implementation and operation of the DCF is

1 no different today than the DCF described in the referenced quotation of Appendix A to
2 Board Order 2015-01.

3 The updates noted in Section 1.2 and 1.3 of Appendix 3.4 do not alter the fundamental
4 principles underlying the DCF or its implementation or operation as described in the
5 above-noted quotes from Appendix A to Board Order 2015-01.

6
7 **(d)**
8

9 Costs due to variances from forecast thermal generation fuel volumes can arise due to
10 different factors. Ratepayer versus YEC responsibility for these costs during periods
11 between GRAs should vary depending on the factors causing the costs, and whether the
12 “ratepayer” is a utility receiving wholesales versus a retail or industrial customer.

13 Costs due to variances from forecast thermal generation fuel volumes should be assigned
14 to the utility when due to total generation load forecast variance¹ or thermal generation
15 unit maintenance requirements², and to ratepayers when due to water or wind forecast
16 variance or other specific factors for which the utility is unable to control and/or the
17 regulator has established deferral or contingency fund cost accounts, e.g., DCF or RFID
18 related thermal generation fuel costs.

19 The DCF and prior contingency funds approved by the Board to assign water-related
20 thermal fuel generation costs to ratepayers in each instance retained YEC responsibility
21 for forecast thermal generation fuel cost variance due to total generation load forecast
22 variance.³ This cost assignment is common practice in Canadian hydro generation
23 jurisdictions.

¹ Yukon experience during the period of Faro mine operation highlighted the impact of major swings in rates when the mine shut down, e.g., the 1993 mine closure lead YEC to seek an average rate increase of almost 60%, of which the Board approved an increase of over 30% (see response to YUB-YEC-2-2(c)). A prime goal of water-variance contingency funds such as the DCF is to smooth out over the long-term life of hydro generation assets the rate impacts related to thermal generation cost changes related to annual water changes.

² This factor is recognized in YEC's 2017/18 GRA. Prior GRA's did not separate out this factor.

³ The Board has been clear that the utilities alone should bear the risk for thermal cost variances due to variances from forecast total generation requirements (noting thermal zone communities as one example where this applies and hydro generation does not exist), while also noting that all parties agree that hydro generation risks related to water lie with the ratepayer (see Section 2.3.1.4 of Appendix A to Board Order 2015-01). The Board has separately, in 2008/09, approved the Purchase Power Flow Through Account for YECL [now AEY] which allows AEY to flow through to its customers any ERA charges incurred due to additional costs incurred by YEC due to changes in wholesale volumes.

1 Please see response to YUB-YEC-2-2(c) for detailed review of relevant GRA filings and
2 Board Orders regarding the principle that risk of low water conditions variance relative to
3 GRA forecasts, as regards added cost of thermal generation, is borne by customers of the
4 utility. See response to YUB-YEC-2-9(e) and YUB-YEC-2-31(c) and (d) regarding
5 contingency fund approaches used with regard to water-related hydro generation
6 variances in other Canadian jurisdictions.

7 Wholesales impacts on YEC are one instance where neither the retail/ industrial
8 ratepayers nor YEC have been responsible for forecast thermal generation fuel cost
9 variance due to total generation load forecast variance. As originally proposed for the
10 ERA, this generation fuel cost variance is shifted from YEC to YECL and would not result
11 in any cost impact to retail or industrial ratepayers. Key factors and documentation in this
12 regard include the following:

- 13 • In accordance with the directions in OIC 1991/92, similar to the current directions
14 in Section 7 of OIC 1995/90 regarding fixing YEC wholesale rates to YECL (AEY)⁴,
15 Order 1993-7 approved a restructured wholesale rate as proposed in the Joint
16 YEC/YECL 1993/94 GRA⁵ to implement the ERA in order to provide a more stable
17 balance of costs and revenues between the two companies in the event that YEC
18 power sales to YECL vary from forecasts on an annual basis.
- 19 • The ERA focus from the outset has been linked to adjusting between forecast and
20 actual wholesale transfers at a rate based on YEC's incremental thermal
21 generation cost (net of revenues received) impacts.
- 22 • As stated in the Joint YEC/YECL 1993/94 GRA, "The new wholesale rate [the ERA]
23 will cause adjustments in transfers between YEC and YECL that balance the
24 changes in revenues and costs caused by sales fluctuations and will have no effect
25 on retail sales."⁶

26 **(e)**

27 Since completion of the Mayo-Dawson Transmission Project, off-grid communities in
28 Yukon are all served by AEY [not YEC].

⁴ Section 7 of OIC 1995/90 includes direction that YEC's wholesale rates for AEY "must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers". Similar directions were provided in Section 4 of OIC 1988/150 and Section 9 of OIC 1991/62.

⁵ See Section 5 of Order 1993-7 (page 5-1) for the Board's review of this matter.

⁶ Joint YEC/YECL 1993/94 General Rate Application, page 3-9.

1 Off-grid communities in Yukon are served entirely by diesel generation, i.e., there is no
2 water risk related to hydro generation as exists on the Yukon grid. The utility (i.e., AEY)
3 pays for forecast thermal generation fuel volume variances for off-grid communities that
4 are due to forecast load variances.

5
6 **(f)**
7

8 No. The DCF does not put ratepayers at risk for all thermal generation fuel volume
9 variances (including fuel volume variances not related to water conditions). The DCF
10 clearly retains utility (rather than ratepayer) responsibility for certain thermal generation
11 fuel volume risks.

12 The DCF as it currently exists applies only to Yukon Energy. As reviewed in response to
13 (d) above, under this DCF Yukon Energy is at risk for thermal generation fuel volume
14 variances that are due to total generation load variances and ratepayers are at risk for
15 thermal generation fuel volume variances that are related to water and wind variances as
16 determined by the DCF (as well as due to RFID-related factors).

17
18 **(g) and (h)**
19

20 Ratepayers do not currently assume 100% of the risk for variances from thermal
21 generation volume forecasts.

22 Historically ratepayers have only carried the risk for thermal generation cost changes
23 related to changes in hydro or wind generation (as well as changes in fuel price). Thermal
24 generation cost changes between GRAs related to changes from forecast total generation
25 load have historically been carried 100% by the utilities.

26 Based on normal regulatory principles, none of the risks related to water variance are
27 borne by the utility. In order to address this requirement, the utility needs to find acceptable
28 methods to adjust rates in response to changes in water conditions. The DCF has been
29 designed to meet this requirement.

1 YEC is not aware of any regulatory precedent for similar hydro electric utilities in Canada
2 where thresholds have been introduced (say +/- 10% of forecast) wherein the utility
3 assumes responsibility for thermal generation volume variances. In the context of the
4 current DCF, introducing such a +/- 10% threshold concept relative to the LTA thermal
5 generation would affect less than 10% of the 35 water years (see Table 3.4-4 of the GRA),
6 add rather than reduce complexity, and move away from established regulatory principles
7 and precedent. Accordingly, YEC is not aware of any such threshold that would be
8 appropriate for the DCF LTA assessment (that would shift water risk to the utility) – nor of
9 any threshold that would be appropriate for the total generation forecast volume (that
10 would shift non-water risk to ratepayers).

11
12 **(i)**

13
14 YEC is unclear what is being proposed in this question.

15 In dealing with water-related variances in thermal generation costs, the regulatory
16 principles and precedent in Yukon is that the risk of low water conditions is to be borne by
17 the ratepayer (see response to YUB-YEC-2-2(c)). On this basis, the suggested option for
18 a new rate rider and deferral account ultimately would impact ratepayers rather than YEC,
19 i.e., mechanisms would continue to be needed to ensure that ratepayers bear the risks
20 and rewards related to water conditions. Impacts on YEC would likely be limited to the
21 relative complexities to administer alternative approaches.

22 The DCF is an established mechanism to achieve rate stabilization related to water
23 variances. The question suggests an option whereby the following occur:

- 24 • **The DCF is replaced.** It currently charges or rebates to the utility for any variance
25 from LTA hydro generation for the grid firm load, subject to caps set by the Board,
26 i.e., charges or rebates to ratepayers occur when the fund goes beyond these
27 caps. Rates to customers are otherwise set based on LTA hydro generation for the
28 grid firm load.
- 29 • **A rider is set for all firm retail and industrial customers “to create a fund or**
30 **deferral account to cover variances for extreme water conditions (flood or**
31 **drought).”** The following elements needed to implement this concept would need
32 to be defined in order to assess the impacts, effectiveness and complexities:

1 o How will rates to customers be set (LTA or short term hydro forecast) and
2 how will forecast thermal generation variances related to water be
3 addressed?

4 ▪ If the DCF is removed and the new fund uses a fixed rider, how will
5 variances in YEC thermal generation costs due to water-based
6 hydro generation variances from GRA forecasts be addressed?

7 ▪ Is it correct to assume that LTA forecasts would likely not work for
8 GRA filings absent a DCF mechanism?

9 ▪ Will YEC need to secure ongoing rate variances (or have a separate
10 deferral account) to address ongoing changes from short-term
11 hydro forecasts due to water variances?

12 ▪ How will the new fixed rider amount be determined? Under what
13 circumstances will the fixed amount be varied?

14 o How will the new fund or deferral account operate, including:

15 ▪ How will water-related variances in thermal generation fuel volumes
16 be determined for the purposes of the new fund?

17 ▪ When will amounts be paid in versus out of the fund?

18 ▪ Will such transfers occur only when there are “extreme water
19 conditions” and, if so, how will these be defined?

20 ▪ What caps (if any) will apply to the new fund?

21 ▪ What happens when the new fund hits the cap, i.e., is the rate rider
22 suspended and/or an added rider applied?

23 A core distinction for any effective deferral account for forecast thermal generation
24 variances related to water is the fund’s ability to handle material (drought) changes in
25 hydro availability.⁷ More information is needed to assess the extent to which the suggested
26 option would in fact vary from the DCF in terms of ratepayer impacts and ability to handle
27 extreme water conditions (drought or flood).

⁷ Board Order 2015-01, Appendix A, page 15 re: directions on matter of DCF cap. The Board also noted an interest in minimizing the frequency of related rider applications (in the context of rate instabilities).

1 **TOPIC: Risk Assignment**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page A2.2-2, PDF
4 page 30

5
6 **QUOTE:** From the outset of Board review of YEC revenue requirements in the
7 late 1980s, it was understood that the risk of low water conditions, as
8 regards added cost for thermal generation, would need to be borne by
9 the customers of the utility.

10
11 **PREAMBLE:**

12
13 **QUESTION:**

- 14
15 a) Is “low water conditions” a defined term?
16
17 b) If “low water conditions” is not a defined term, please provide a definition of
18 low water conditions and an explanation for YEC’s working use of the term.
19
20 c) On what basis did YEC conclude that the risk of low water conditions, as it
21 relates to additional cost for thermal generation, is to be borne by the
22 ratepayers? Was this statement made in a Board decision? If so, please
23 provide the excerpts from that decision.
24

25 **ANSWER:**

26
27 **(a) and (b)**

28
29 “Low water conditions” is not a defined term. In the context of the current GRA and the
30 DCF, such conditions are considered to exist when actual hydro generation is below long
31 term average hydro generation due to lack of water. In the broader context of the above
32 quote and earlier GRAs prior to adoption of LTA hydro forecasts, such conditions
33 reference the risk of higher-than-GRA-forecast thermal generation costs due to lower-
34 than-forecast water conditions resulting in lower-than-forecast hydro generation.

1 Looking at current grid loads and conditions, thermal generation higher than LTA will be
2 required in years when hydro generation water conditions are less than the LTA.

3
4 Appendix 3.4, Attachment 3.4.2 (Table 3.4-4), indicates that at approximate 2018 GRA
5 load levels (420 GWh/year), LTA thermal generation over the 35 water years of record is
6 13.9 GWh/year. The information outlines impacts on thermal generation at the 420
7 GW.h/year load in water years with “low water conditions” relative to the LTA:

- 8
9 • By way of example, a repeat of water conditions experienced in 1998 would result
10 in 31.2 GWh/year of thermal generation (2.25 times the LTA thermal generation of
11 13.9 GW.h/year).
- 12
13 • A repeat of water conditions experience in 1999 would result in 107.5 GWh/year
14 of thermal generation (7.73 times the LTA thermal generation of 13.9 GW.h/year).
- 15
16 • In summary, “low water conditions” with thermal generation in excess of 13.9 GWh
17 [LTA] at the 420 GW.h grid load would be required in 10 of the 35 water years
18 [thermal generation requirements in excess of LTA range from 14.2 GWh in 2003
19 to 107.5 GWh in 1999], and these 10 low water years (at the 430 GW.h load) are
20 consecutive.

21
22 The same Table 3.4-4 shows how the LTA and low water condition water years vary with
23 different grid loads. The response to John Maissan-YEC-1-21-Revised, for example,
24 includes assessment in this table at a load of 490 GW.h/year (approximate 2018 load level
25 with VGC Group load added). At this higher load, the LTA is 51.1 GW.h/year and “low
26 water conditions” with thermal generation in excess of 51.1 GWh [LTA] would be required
27 in 16 of the 35 water years [thermal generation requirements in excess of LTA range from
28 51.8.0 GWh in 1982 to 125.5 GWh in 1999], and the 16 low water years are not all
29 consecutive.

30
31 Please see YUB-YEC-2-12(b) for review of fuel cost impacts related to the above low
32 water condition examples.

1 (c)

2
3 Yukon Energy made this conclusion based on its understanding of GRA filings and Board
4 Orders throughout the period that Yukon Energy has been regulated by the Board.

5
6 Yukon Energy's understanding is that it has long been a principle in this jurisdiction that
7 risk of low water conditions, as it relates to additional cost for thermal generation, is to be
8 borne by the ratepayers. This principle has been implicit in the operation of the DCF as
9 well as the earlier Low Water Reserve Fund (LWRF), and has been accepted by the Board
10 and intervenors as evidenced in prior GRA proceedings and related Board Orders
11 approving the operation of each of these funds.

12
13 The relevant history of GRA filings and Board Orders related to this principle is detailed
14 below.

15
16 ***Yukon Energy 1989/90 GRA and Order 1989-4***

17
18 Yukon Energy's first GRA filing with the Board for the 1989/90 GRA indicated that a reserve
19 of \$2,250,000 had been established by YEC out of retained earnings in 1987 to assist in
20 maintaining rate stability in the event of uninsured losses and additional costs resulting
21 from low water levels¹. Of this amount \$2,000,000 was established to protect against
22 increased costs to produce electricity by diesel generation at times of low water conditions
23 and shutdowns of hydro facilities; it was noted that this would enable the Company to
24 cushion the impact of low water conditions before having to ask the Board for an increase
25 in consumer rates.² At that time, the Company explained that the reserve would be
26 replenished when drawn down, and noted options in this regard to include an application
27 for a special surcharge rider, provision for amounts as a portion of YEC's revenue
28 requirement at a GRA, or a charge against retained earnings.³ Company witnesses also
29 agreed that if risk of low water conditions of a utility is borne by the customers of the utility,
30 then the compensation to investors of the utility should be less than would otherwise be⁴.

¹ 1989/90 GRA, page 2-28.

² See Order 1989-4, page 19.

³ Ibid.

⁴ See Order 1989-4, page 20.

1 While the Board provided no specific comment on the reserve fund in its reasons, the Board
2 Order quoted the following basis for the fund as provided by Company witnesses⁵:

3
4 “The provision has been made that the owners of the utility, who are in the end the
5 people, have set aside from retained earnings before regulation a healthy sum so
6 that the owners are in fact taking the first crack at the reserve fund. **Based on the**
7 **NCPC experience and experiences in other jurisdictions, though, it would be**
8 **appropriate in the long run for the consumers of the utilities to be paying for**
9 **their own contingencies.**” Emphasis added.

10
11 In summary, Yukon Energy’s first filings with the Board on this matter indicated that, based
12 on the prior NCPC experience and experiences in other jurisdictions, the consumers of the
13 utilities in effect bear the ongoing risk of additional costs from low water conditions, and
14 that it would be appropriate in the long run for these consumers to be paying for their own
15 contingencies. See YUB-YEC-2-2(c) Attachment 1 for the relevant excerpts of the 1989/90
16 GRA and Board Order 1989-4.

17
18 ***Yukon Energy 1991/92 GRA and Order 1992-1***

19
20 The 1991/92 GRA and Order 1992-1 re-affirmed the principle that ratepayers, and not the
21 utility shareholders, receive the benefits as well as the added costs resulting from changes
22 in hydro forecasts from GRA forecasts.

23
24 The 1992 GRA revenue requirement was adjusted in October 1991 [subsequent to the
25 GRA being filed June 6, 1991] in part to reflect higher than expected 1991 water flows that
26 would enable YEC to save diesel fuel and O&M costs of \$4,057,000 [reducing the potential
27 impact on YEC’s revenue requirement by \$2,000,000].⁶ Above average rainfall during the
28 summer filled the Aishihik reservoir to the full supply level, increasing available hydro
29 generation from 107 GWh as forecast in the GRA to 150 GWh; and consequently reducing
30 forecast diesel generation requirements by 43 GWh [from 91.6 GWh to 48.6 GWh].

⁵ Ibid.

⁶ The initial GRA application submitted in June 1991 noted increased costs to providing service related in part to “increased energy consumption and the decrease in hydraulic generation. This increased diesel generation is due primarily to the depletion of the Aishihik Lake storage system.”

1 Yukon Energy sought the following approvals regarding implementation of the Low Water
2 Reserve Fund (LWRF) as part of the October 1991 revision during the 1991/92 GRA⁷: (1)
3 that the reserve be established in the manner proposed⁸; that a \$4 million maximum
4 amount be approved for the reserve; and that the Board approve an update to YEC's initial
5 Application [October 21, 1991 update] that would increase forecast Aishihik generation
6 from 107 GWh to 150 GWh for the 1992 test year based on higher-than expected water
7 availability which occurred after filing the initial Application in June 1991.

8
9 In its application, YEC specifically noted as follows regarding its previously established
10 contingency reserve⁹:

11
12 “YEC's contingency reserve remains, from the previous Application, as an
13 unfunded reserve for low water (\$2.0 million) and a reserve for uninsured losses
14 (\$250,000). This reserve is treated as no-cost capital in the GRA, reflecting its use
15 to fund YEC's rate base. ***It is the intention of YEC that this reserve be treated***
16 ***as a customer operating reserve rather than as part of Shareholders' equity,***
17 ***with appropriations and withdrawals in future being reflected in the statement***
18 ***of income prior to determination of net income.***” [Emphasis added]

19
20 The principles underlying the fund and risk allocation were summarized as follows by
21 Yukon Energy witnesses [as summarized by the Board in Order 1992-1]¹⁰:

22
23 “I think that's the important thing to focus on from the customers' point of view, is
24 that it [the low water financial reserve] takes any excess earnings which result from
25 a factor such as rainfall, and makes sure that the customers eventually get it.

⁷ As summarized in Board Order 1992-1, page 51.

⁸ Board Order 1992-1, page 49 summarizes the Board's understanding of how the LWRF would be implemented as follows in relation to the GRA: (1) the Company will determine the level of the lake [Aishihik] at the time the forecast is prepared; (2) the Company will forecast average water inflows during the year; (3) based on steps (1) and (2) the Company will forecast the amount of hydro generation and thus the required amount of diesel generation; and (4) at the end of the year the Company will determine if the forecast diesel generation differed from actual experience due to water flows and if so the reserve will be increased or decreased accordingly.

⁹ 1991/92 GRA, pages 2-24 and 2-25.

¹⁰ See Order 1992-1, page 47.

1 “As I stated before, in the case of a low water year, we would be inclined, I think [in
2 the absence of such a reserve], to come back to the Board for higher rates in a year
3 because the potential impact is quite large.”
4

5 The Board indicated in Order 1992-1 concern that “the use of the ‘level of the lake at the
6 time the (hydro) forecast is prepared’ as proposed in the October 1991 update rather than
7 using a hydro generation forecast based upon long term average hydro generation may
8 lead to rate instability.”¹¹ While the Board accepted the hydro generation forecast for 1992,
9 it noted an expectation for Yukon Energy to present evidence relating to the advantages
10 and disadvantages of using current water levels as compared to long term average hydro
11 generation. The Board approved the LWRF but noted that all matters relating to the low
12 water reserve would need to be re-examined at the next general rate application.
13

14 See response to YUB-YEC-2-3(a) Attachment 2 which provides the relevant excerpt of
15 Order 1992-1 approving the Low Water Reserve Fund as applied for in the 1991/92 GRA.
16

17 ***Yukon Energy 1993/94 GRA and Order 1993-8***
18

19 The 1993/94 GRA occurred after the Faro mine (as then operated by Curragh Resources)
20 had shut down, and YEC was required as a result to seek a very large rate increase (i.e.,
21 the revised application sought a cumulative increase through January 1994 of 58.62% over
22 1992 rates)¹² to address the large overall loss of net income to fund rate base. In this
23 context, hydro generation forecasts were not a material consideration in determining the
24 test year revenue requirements.
25

26 The benefits of the low water reserve fund, as well as pros and cons related to using long
27 term average generation versus short term forecasts based on current Aishihik Lake levels,
28 were reviewed (as previously directed by the Board) in the 1993/94 GRA, Volume 1, Tab
29 5, pages 5.0-6 to 5.0-11 [see Attachment YUB-YEC-2-2(c) Attachment 2]. It was noted that
30 “diesel generation cost variance from GRA forecasts in any year will reflect many factors,
31 including variances in overall sales, diesel fuel prices, equipment availability, and water
32 flows”; however, the low water financial reserve “is to be affected only to the extent that

¹¹ At page 52 of Order 1992-1.

¹² See Decision 1993-8, page 6. The Board approved a cumulative increase of 31%, a reduction of almost one-half of the increase requested by the Companies.

1 diesel generation variance is directly related to water flow variances that have affected
2 hydraulic generation”.

3
4 Intervenors had proposed that, since Curragh was expected to remain off the system during
5 the test years, little diesel would be required and the level of the reserve could be reduced
6 “without significant risks to ratepayers”. At page 70 of Order 1993-8 approving YEC’s
7 updated GRA filing, the Board notes its agreement with the parties that a reasonable
8 drawdown of the LWRF can be effected to reduce rates in the current Test Years without
9 creating undue risk for future customers.

10
11 See YUB-YEC-2-2(c) Attachment 2 for the relevant excerpts of the 1993/94 GRA, Volume
12 1, Tab 5, Pages 5.0-6 to 5.0-11 and Board Order 1993-8.

13
14 ***Yukon Energy 1996/97 GRA, Negotiated Settlement and Order 1996-7:***

15
16 The 1996/97 GRA occurred after Faro mine operation had resumed in 1995, and the added
17 YEC net income resulting from these resumed operations had in effect been made interim
18 and refundable by Board Order 1995-01. In this context, hydro generation forecasts had
19 once again become relevant for GRA revenue requirement determinations. The filings,
20 settlement agreement, and Board Order all reaffirmed the principle that the risk of low water
21 conditions, as it relates to the cost for thermal generation, is to be borne by the ratepayers.
22 This is the first GRA when hydro generation forecasts for the test years (and therefore
23 related thermal generation forecasts for the test years) were approved based on LTA hydro
24 generation estimates.

25
26 In the 1996/97 GRA, the Companies noted that significant variance in water flows “led the
27 Companies to reassess their position with respect to the use of the low water reserve
28 fund.¹³” As part of the 1996/97 GRA the Companies proposed shifting from short-term
29 forecasts, based on Aishihik Lake levels at the time of filing, to LTA hydro forecasts. The
30 Companies noted that potentially large fluctuations in rates caused by variances in
31 available water flows warranted moving to LTA for determining rates, and proposed to use
32 the LWRF as a Rate Stabilization Fund to “absorb annual fluctuations in available water
33 resources without resorting to massive rate fluctuations from year to year.”

¹³ 1996/97 GRA, page 2-4.

1 The 1996/97 GRA was subject to a Negotiated Settlement process which established the
2 Diesel Contingency Fund [to replace the Rate Stabilization Fund as proposed in the
3 1996/97 GRA], and which was to “operate to smooth customer rate changes and offset
4 forecast diesel costs.”

5
6 The Negotiated Settlement established that “rates and the fund will be determined using
7 the long-term average water expected to be available for generation (105 + 246 GWh)”;
8 and “the fund is only to be used for the purposes of stabilizing customer rates and
9 offsetting diesel generation cost estimates and the fund is not to be accessed for other
10 reasons including government subsidy of rates.”¹⁴ The Negotiated Settlement was
11 approved by the Board in Order 1996-7. The Board noted that it was satisfied that the
12 settlement agreement was in the best interests of the public and accepted the settlement
13 package as presented.

14
15 See YUB-YEC-2-2(c) - Attachment 3 for the relevant excerpt of Yukon Energy’s 1996/97
16 GRA Application. See YUB-YEC-2-3(d) – Attachment 1 which provides a copy of the
17 Negotiated Settlement. See also YUB-YEC-2-3(c) – Attachment 1 which provides Order
18 1996-7, including materials relevant to the negotiated settlement.

19
20 ***1999 YUB Review of DCF – Order 1999-3***

21
22 The Board in 1999 reviewed the DCF purpose and implementation for the period 1996
23 through 1998, and approved in Order 1999-3 the additions and deletions to the fund over
24 that initial period. See YUB-YEC-2-3(d), Attachments 2-4 for YEC letters reviewing the
25 DCF over this period, and Order 1999-3.

26
27 The question as to why a DCF (or similar rate stabilization mechanism) is needed was
28 reviewed in this 1999 proceeding and summarized in a letter by Yukon Energy to the
29 Yukon Utilities Board (based on an excerpt from a report to the YUB in April 1997 prepared
30 by the Accounting firm Stephen Johnson - see YUB-YEC-2-3(d), Attachment 3):

31
32 “In certain jurisdictions, electric power is generated at hydro dams or run-of-the-
33 river hydro operations. Low Water Reserves have been established to protect

¹⁴ See March 11, 1996 Letter from Bill Grant to Bill Byers regarding Proposed Settlement of Issues Concerning the Revenue requirement and Rate Design Application of YEC and YECL attached to Order 1996-7.

1 customers against short term fluctuations in the cost of electricity when more costly
2 sources of generation, such as diesel, are substituted for hydro generation at times
3 of low water conditions behind the dams or in the rivers. Simply, lower than
4 average water level conditions generally result in higher diesel generation costs...”

5
6 “Given that the reserve is a vehicle for smoothing the cost fluctuations due to water
7 level divergence from average, it is set up so that it can be drawn down to offset
8 the costs of diesel generation in years of low water levels.”
9

10 The same letter noted that “the DCF is set up so to replenish in years of high water levels.
11 The result is better rate stability and predictability for both customers and utilities.”
12

13 ***2014 DCF/ERA Proceeding***
14

15 The premise for, and principles underlying the DCF have most recently been reviewed as
16 part of the 2012/13 GRA [where the DCF was updated and reactivated] and the 2014
17 DCF/ERA Proceeding. These proceedings reaffirmed the principle that the risk of low water
18 conditions, as it relates to the cost for thermal generation, is to be borne by the ratepayers.
19

20 As reviewed in response to YUB-YEC-2-3(b), surplus hydro conditions following closure of
21 the Faro mine resulted in suspension of the DCF from 1998 until 2012. Under these
22 conditions, hydro generation forecasts were once again not a material consideration in
23 determining the test year revenue requirements in the GRA proceedings that occurred for
24 2005 and 2008/09. The 2012/13 GRA therefore re-implemented the principles related to
25 the DCF and the adoption of LTA hydro forecasts for GRA purposes.
26

27 In Order 2015-01 approving the DCF the Board noted that “all Parties to this proceeding
28 agree that there is a need for a mechanism that effectively protects ratepayers from diesel
29 generation cost impacts caused by fluctuation of hydro generation due to water conditions
30 or changes in wind conditions.”¹⁵ Further, the Board accepted the DCF as proposed by
31 YEC “because it is a fund for customers to smooth rate impacts for those occasions when
32 hydro generation is less than LTA or to build up the fund when hydro generation is greater
33 than LTA.”¹⁶

¹⁵ Order 2015-01, Appendix A, page 11.

¹⁶ Order 2015-01, Appendix A, page 14.

- 1 See YUB-YEC-2-2(c) - Attachment 4 for the relevant excerpt of Order 2015-01.

2.5

1987 Financial Statement

Since acquiring the utility assets in March 1987, YEC's financial performance has been better than expected. Gross revenues were \$15.6 million in 1987 (9 months) and are anticipated at \$22 million in 1988. Net income was \$6.7 million in 1987 (see Section 6) and is projected at \$9.8 million in 1988 (see Section 5, Schedule 6). This positive performance is due to a number of factors which reduced costs below what was anticipated at the time of the transfer, while rates remained fixed at their March 31, 1987 levels.

A two year rate freeze expiring April 1, 1989 was implemented as part of the transfer from the NCPC to the Yukon Government (See Section 2.3). Relative to annual 5% increases which NCPC was contemplating immediately prior to the transfer, the two year freeze was seen at that time as providing considerable benefit to Yukon consumers. X

Several favourable events occurred during the rate freeze period. Diesel fuel costs dropped from about 11 cents/kW.h in 1986 to about 7 cents/kW.h in late 1988. After a lengthy 4 year shutdown, the Curragh mine resumed operations in 1986. Energy consumption increased from 261 GW.h in 1985 to 374 GW.h in 1987 to 383 GW.h in 1988. In addition, non-fuel operating costs were lower than anticipated. There were some offsetting negative influences throughout this period such as a labour strike at the Curragh mines; however, the positive factors had a much greater impact than the negative ones.

YEC's earnings are being and will be used to improve the utility's capability to serve its customers. YEC has established a Contingency

2-26

Reserve of \$2.25 million out of its 1987 earnings (see Table 1) to protect against injury and property claims, increased costs to produce electricity by diesel due to low water conditions, and shutdowns. The appropriation of income for 1987 was as follows:

Self insured loss	\$ 250,000
Low water expense	<u>2,000,000</u>
Total	\$ 2,250,000
	=====

The Contingency Reserve is included in equity as no-cost capital. Other YEC equity at the end of 1987 was provided by \$39 million of share capital and \$3.6 million of retained earnings. In total, YEC equity at the end of 1987 equalled \$44.8 million (45% of total equity and long term debt).

After extensive cross-examination on the subject of YEC's dividend policy and its inter-relationship with the subsidy program, YEC's witnesses were unable to explain the policies in a clear and unambiguous fashion. Consequently the Board directs that prior to the time of its next general rate application YEC present a clear explanation of this matter.

4.4.3. Reserve for Contingencies

During the course of the proceeding, Company witnesses explained that a reserve of \$2,250,000 was established out of retained earnings in 1987. Of this amount, \$250,000 was established to protect against injury and property claims and \$2,000,000 was established to protect against increased costs to produce electricity by diesel generation at times of low water conditions and shutdowns of hydro facilities. The reserve of \$2,000,000 would enable the Company to cushion the impact of low water conditions before having to ask the Board for an increase in consumer rates.

Company witnesses explained that in the event that the reserves were drawn down as a result of such events, it would be the Company's intention to replenish the reserve. It was also explained that the reserve would be replenished, either by charges against retained earnings, the inclusion of the amount required to replenish the reserve as a portion of YEC's revenue requirement at a general rate application, or by an application to the Board for a special surcharge rider. As shown in Section 5, Schedule 4, the balance of \$2,250,000

YUKON UTILITIES BOARD
DECISION 1989-4

PAGE 20.

is shown as "No Cost Capital", and accordingly no return on this amount is provided for in the Company's revenue requirement. As explained by Company witnesses at page 402 of the transcript:

"The provision has been made that the owners of the utility, who are in the end the people, have set aside from retained earnings before regulation a healthy sum so that the owners are in fact taking the first crack at the reserve fund. Based on the NCPC experience and experiences in other jurisdictions, though, it would be appropriate in the long run for the consumers of the utilities to be paying for their own contingencies."

Company witnesses also agreed that if the risk of low water conditions of a utility is borne by the customers of the utility, then the compensation to investors in the utility should be less than it would otherwise be.

4.4.4 Position of the Board

In its Decision 1989-3 the Board found a fair rate of return for common equity capital of YECL to be 13.5% for 1989 and 1990. After considering all of the evidence presented at the Hearing, together with Arguments and Replies of the parties, and taking into consideration its finding of a fair return for common equity capital of YECL and the existence of the reserve fund of YEC, the Board finds a fair rate of return for common equity capital of YEC to be 13.25% for 1989 and 1990.

Having considered the forecast capital structure submitted by YEC to be appropriate for the fixing of the fair return on rate base, and having considered the cost rates of the components of the capital structure for YEC which are assumed to be financing the forecast rate base, the Board hereby fixes for the test years the fair return on rate base for YEC as follows and as set out in Schedule "B" attached:

1989 Forecast	\$9,375,104
1990 Forecast	\$9,842,592

5. ELECTRIC UTILITY REVENUE REQUIREMENT

5.1 Control Over Operating and Maintenance Expenses

Company witnesses explained that control over the operating expenses of YEC is exercised by its Board of Directors. In response to a question on this matter, Mr. Alwarid stated:

"Mr. Chairman, the budget is set by the Board of Directors, certain operating expenses are recommended by the manager [YECL] as to the operation of the utility, the other operating expenses related to YEC's office are recommended by the executive director to the Board, and in turn the Board has to approve them."
(Transcript Page 427)

Mr. Alwarid further explained that there is an annual budget which is submitted to the Board for its approval, and also quarterly variance reports which are examined by the Board. In addition, the manager submits monthly reports to the monthly meetings of the Board of Directors of YEC. With respect to the forecasting process, the Board of Directors determines forecast operating expenses after receiving the advice of the manager.

5.0-6

The companies have experienced difficulties in determining appropriate measures of labor productivity. Unlike most other utilities the unit cost of electricity in Yukon can increase as the sales increase, due to the fact that diesel generation has been used for the margin. Productivity measurements can also show increases when Curragh is closed and only hydro generation is used. Historical reviews can be meaningless in light of these factors.

Discussions with other power utilities indicates similar concerns about determining appropriate productivity measures of labor particularly on historical and forecast basis.

Low Water Financial Reserve

Section 7 in Decision 1992-1 requested YEC to present evidence in the next GRA relating to the advantages and disadvantages of using current water levels as compared to long term average hydro generation when calculating additions to, or deletions from, YEC's low water financial reserve.

Background on the Reserve

As reviewed in the Board's decision, the basic concept of the low water reserve as modified in the 1991/92 GRA is as follows:

- (a) no direct charge for this reserve is included in forecast revenue requirement in a GRA

5.0-7

- (b) if YEC over-earns in a year because the actual diesel generation is less than the forecast diesel generation due to higher than forecast water flows, the reserve would be increased to the extent of the difference between forecast and actual diesel generation (reflecting incremental costs saved for diesel generation) up to a maximum reserve of \$4 million
- (c) if YEC under-earns in a year because actual diesel generation exceeds forecast diesel generation due to lower than forecast water flows, the reserve would be decreased.

Each GRA is prepared on the basis of forecast sales, long term average water flows for the prospective test years, and the storage then available at Aishihik Lake. YEC does not, however, seek Board approval for specific levels of generation at each hydraulic plant; as events occur, YEC is required to respond to actual sales, generation needs, equipment availability, water levels and other conditions so as to minimize costs. As a general operating rule normal to similar utilities in Canada, available water is utilized (subject to water licence terms and conditions) to minimize fuel operating costs.

Diesel generation cost variance from GRA forecasts in any year will reflect many factors, including variances for overall sales, diesel fuel prices, equipment availability, and water flows. The low water financial reserve, however, is to be affected only to the extent that diesel generation variance is directly related to water flow variances that have affected hydraulic generation.

Application of Reserve: 1992 Actual Results

5.0-8

By way of example, in 1992 the following annual variances between actual and GRA forecast occurred in the WAF system of YEC:

- o hydro generation: 3.1 GW.h
- o diesel generation: (15.1) GW.h
- o total generation: (12.0) GW.h

The above 1992 results indicate an overall reduction in sales (and thus total generation) of 12 GW.h relative to the GRA forecast. However, diesel generation savings were 3.1 GW.h greater than the reduction in overall generation and, after review, it was concluded that this 3.1 GW.h reflected higher than forecast water flow. The increase to the low water financial reserve for 1992 was then determined as follows:

- (a) calculate WAF fuel cost saved based on GRA approved costs for 1992 (28.6¢ per litre at fuel efficiency of 3.65 kW.h/l) equals 7.83562¢ per kW.h
- (b) assumed variable O&M cost saved as per 1992 GRA, at 1.5¢ per kW.h diesel generation
- (c) calculated diesel generation cost saved in 1992 due to higher than forecast water flows equals \$292,462 = (3,132,760) (\$0.093356).

Advantages and Disadvantages of Using Current Aishihik Levels

The Board expressed concern in Decision 1992-1 that use of a hydro generation forecast which reflects the level of Aishihik Lake at the time when the forecast is prepared (rather than using long term average hydro generation) may lead to rate

5.0-9

instability. The Board requested YEC to present evidence on the advantages and disadvantages of these two options.

The Companies want to clarify that the initial GRA Application filed in June 1991 and the October 1991 update both used the level of Aishihik Lake at the time each of the hydro forecasts were prepared in order to forecast hydro generation for 1992. At no time have the Companies prepared a GRA which ignored the level of Aishihik Lake existing at the time when the hydro forecast is prepared. Each hydro forecast reflects the lake level then existing, assumes long term average water inflows for the future, and assumes that whatever storage may exist at Aishihik Lake will be used within the limits permitted by the water license and YEC's water management policy.

The low water reserve is intended to be calculated on the basis of deviations from the hydraulic generation forecast adopted when the Board sets rates for the test years. In 1992, the Board accepted the updated 1992 hydro generation forecast for Aishihik (which increased forecast generation for 1992 from 107 to 150 GW.h based solely on higher-than-expected water availability which occurred after filing of the initial Application in June 1991). The low water financial reserve allows both YEC and the customers to be protected against earnings and/or rate instability due to water availability variance from forecasts used in each GRA. If the Board had set 1992 rates based on long term average hydro generation at Aishihik (which was then estimated at 100 GW.h/yr), incremental costs for an extra 50 GW.h of diesel generation would have been required in the 1992 revenue requirement. Based on the WAF incremental fuel costs reflected in the Board's 1991/92 GRA decisions, such an adjustment would have had the following impacts on 1992 rates and reserve calculations:

5.0-10

- o the 1992 revenue requirement approved by the Board would have had to be increased by about \$4.7 million (this would have significantly increased 1992 rates)
- o the year-end 1992 low water reserve would presumably have been calculated relative to long term average hydro generation and diesel generation; thus the apparent "saving" in diesel generation would have been 53.1 GW.h (rather than 3.1 GW.h); the low water reserve would then have been increased to its maximum of \$4 million, and the balance of almost \$3 million would have gone to increase YEC earnings.

In short, ignoring the level of Aishihik Lake when there is usable storage can lead to higher-than-necessary rate levels for consumers in the test years as well as the likelihood that YEC will "over-earn" on rate base (e.g., even if the Aishihik water availability in 1992 had been below the long term average, the above example would still have probably indicated an apparent saving in diesel generation relative to the forecast). These problems will not exist, of course, if no usable storage exists in the lake when the forecast is prepared; however, in this situation, long term average hydro generation would equal the most likely forecast for the test years (based on the lake level at the time when the forecast is prepared).

The above analysis demonstrates the main advantage of using forecast Aishihik hydro generation, reflecting current Aishihik Lake water levels, as compared to using long term average Aishihik hydro generation for the purpose of the low water reserve. The present approach allows the Companies to set rates based on the best available forecast of hydro generation; this in turn allows consumers to benefit during test years from reduced diesel generation forecast on the basis of current Aishihik Lake water

5.0-11

levels. The present approach also minimizes the year-end reserve adjustments likely to be required whenever current Aishihik Lake water levels are expected to permit Aishihik hydro generation higher than the long term average level.

The Companies also note that the main disadvantage of the present approach is that it contributes to rate instability to the extent that successive GRA's are required to adjust rates in response to current Aishihik Lake levels. Setting rates (and therefore reserve calculations) in each GRA on the basis of long term average hydro generation at Aishihik Lake would remove any instability in rates due to Aishihik Lake level fluctuation; however, it would have achieved this result in 1992 by requiring higher consumer rates and greater year-end reserve adjustments. Whenever Aishihik hydro generation is forecast to exceed the long term average (such as in 1992) due to current lake levels, the Companies see significant problems for consumer rates if the reserve is calculated using long term average hydro generation.

The present approach simply allows the Board and the utilities to set rates based on the best available forecast of hydro and diesel generation; such a forecast must reflect current Aishihik Lake levels, as well as various other factors such as forecast sales. Generation forecasts are still prepared assuming long term average water inflows for each test year to Aishihik Lake and Whitehorse Rapids; and adjustments at year-end to the low water reserve are designed solely to reflect variances in water availability relative to the GRA forecasts.

5.1.3.2 YEC/YECL POSITION

The Companies submitted in Exhibit 134 that the Curragh bad debt does not qualify as an extraordinary item and should be included as a legitimate cost in the year incurred. The Companies, in their Argument, requested that the Curragh bad debt be included as a 1993 expense or amortized over five years beginning in 1993.

5.1.3.3 BOARD FINDINGS

The Board directs that the Curragh bad debt of \$815,000 be removed from O&M expense in 1993 and amortized over five years commencing in 1993, during which time the Board will allow a return on the unamortized balance.

The Companies indicated that the proposed rate design will allow for a reduction to the 1994 rates charged to customers should amounts related to the Curragh bad debt be recovered. The Board directs that in the event that any portion of the Curragh bad debt is recovered at any time, then that amount shall be applied to the benefit of YEC's and YECL'S customers.

5.1.4 LOW WATER RESERVE

As explained in previous Decisions, the Low Water Reserve was established by YEC out of retained earnings to protect against increased costs to produce electricity by diesel generation at times of low water conditions and shutdowns of hydro facilities. As at December 31, 1992, the balance in YEC's Low Water Reserve account was approximately \$2.3 million. In the revised application, the Companies had proposed not to add to or draw on the reserve during the Test Years 1993 and 1994.

5.1.4.1 CITY POSITION

The City in its Evidence noted that, if Curragh were to remain off the system during the Test Years, little diesel power would be required. Therefore, the level of the Low Water Reserve could be reduced without significant risks to ratepayers. The City's witness recommended that the Low Water Reserve be reduced by \$1 million over the period July 1, 1993 to December 31, 1994 in order to help mitigate the proposed 1993/94 rate increases.

5.1.4.2 YEC/YECL POSITION

In response to the City's request, YEC reviewed the possibility of reducing the Low Water Reserve. Under the assumption that the Faro mine does not reopen, YEC determined that the existing level of the reserve at \$2.3 million can be reduced to \$500,000 over the Test Years. The \$1.8 million reduction reflects the estimate of increased diesel generation that could occur over two years of low water conditions. YEC submitted that, under the reduced load conditions, a future ceiling for this reserve should be \$1 million to reflect load growth through to the year 2000. If, however, increases in the load required significant diesel generation, the ceiling of the reserve should return to the \$4 million level. The Companies recommended that the requirements for the Low Water Reserve should continue to be reviewed at least every two years.

The Companies proposed to reflect the reserve reduction directly in the form of rate relief to non-government residential and commercial customers. The Companies did not propose a reduction in revenue requirement. Witnesses for YEC indicated that this proposal had received the approval of YEC's Board of Directors on the presumption that the Faro mine remains closed. The Companies proposed to allocate \$400,000 and \$1,400,000 of the total reduction to the reserve to 1993 and 1994, respectively. The rate relief as proposed by the Companies would entail a one-time reduction in bill increases of approximately 14 to 16 percentage points for eligible sales.

5.1.4.3 BOARD FINDINGS

The Board agrees with the parties that, under the present circumstances, a reasonable drawdown of the Low Water Reserve can be effected to reduce rates in the current Test Years without creating undue risk for future customers. The Board accepts the Companies' proposal to reduce the Low Water Reserve by \$400,000 in 1993 and \$1,400,000 in 1994. However, the Board does not agree with the Companies' proposal to use the drawdown directly in the form of rate relief. The Board directs that the reduction in the Low Water Reserve be applied as a reduction to the revenue requirement.

5.1.5 RESERVE FOR INJURIES AND DAMAGES

During cross-examination, a company witness indicated that the Companies intend to increase the reserve for each of YEC and YECL by \$51,500 and \$53,000 in 1993 and 1994, respectively. The witness also explained that the Companies are targeting for reserves of \$250,000 for YEC and \$100,000 to \$150,000 for YECL based on experience and insurance deductibles.

Proposed Rate Stabilization Fund

The very significant variance in water flows over the past three to four years has led the Companies to reassess their position with respect to the use of the low water reserve fund. If the Companies had been using their past practice of adjusting for actual reservoir elevations, the revenue requirement in this Application would not be materially different. There is also a significant risk that actual Aishihik water flows will continue to be below average in 1996 and 1997. We believe our suggested increases to the low water reserve fund address this risk.

The Companies believe that the potentially large fluctuations in rates which will be caused by variances in available water flows at the system hydro sites warrants a move to long-term average hydro generation for the purposes of determining rates. The low water reserve fund would then be used as a Rate Stabilization Fund to absorb the annual fluctuations in available water resources without resorting to massive rate fluctuations from year to year.

The benefits of amending the generation forecasting process and the operation of the low water reserve/rate stabilization fund would be as follows:

- low or no rate fluctuation from year to year caused by changes in water flows;
- greater certainty for customers on the future level of rates;
- simplification of the generation forecasting process; and
- the potential to extend test periods and reduce long-term regulatory costs due to a defined adjustment which will control the fluctuation in a significant cost item.

The mechanism for this new "Rate Stabilization Fund" would operate in the same manner as the currently approved low water reserve fund. The only difference would be that the "forecast" hydro generation would always be long-term average generation instead of an ever-changing forecast of hydro generation based on changes in available water from year to year.

The Companies would also like to include YECL's Fish Lake facility and YEC's wind generator in the operation of the reserve. This change fits in with the goal of providing long-term stability to rates and ensures customers receive the benefit of high flow years and the shareholder is protected from the risk of low flow years.

The Companies believe that the ceiling for this fund must be at least \$5 million as this represents the impact of only one year's fluctuation in extreme conditions. The Companies wish to study the potential swings in this fund and may propose a higher ceiling at a future hearing. Our initial review of this fund is that it may be more volatile than the low water reserve due to the fact that generation forecasts will not be updated for actual water conditions at the beginning of each test period.

In Volumes I and II, the Companies have accounted for the Rate Stabilization Fund as a reduction in the rate base as directed in prior Board decisions. The Companies propose, however, that the fund be removed from rate base and that all interest income or expense on the fund be charged directly to the fund. This proposal retains the benefit of having all of the financing benefit going to the account of the customers but removes the circular calculations and volatility resulting from including the fund in rate base.

shock is still an obtainable objective⁴³ and therefore submitted that a DCF cap of \$4 - \$5 million is preferred.⁴⁴

Regarding YEC's use of the YECSIM model, UCG made the following comments:

With respect to YEC's position that annual YECSIM model determinations of "expected default diesel generation" are appropriate for the DCF, UCG repeats its argument that it is detrimental to the review efforts of the YUB and stakeholders to have YEC refuse to provide all the data, calculations and assumptions used to derive the YECSIM model by hiding behind a proprietary model claim.⁴⁵

... it is still important for an independent review of the model to verify that it is the optimal program to be using.⁴⁶

UCG agrees with AEY's [YECL's] argument that YEC's DCF proposal appears to be excessively and unnecessarily complex and agrees with AEY's [YECL's] conclusion that a complex and untestable model like the YECSIM to attempt to forecast diesel volumes and then using the same model to calculate the amount to which the forecast is trued up, goes against basic principles of deferral accounts and causes unnecessary complexity.⁴⁷

2.1.1.4 Views of the Board

The Board notes that all Parties to this proceeding agree that there is a need for a mechanism that effectively protects ratepayers from diesel generation cost impacts caused by fluctuation of hydro generation due to water conditions⁴⁸ or changes in wind conditions. The question before the Board is: How is this best accomplished? Currently, there are three models for the Board to consider: YEC Option A, YEC Option B and YECL Diesel Deferral Account (DDA), which is discussed later in these reasons.

YEC's Option A and Option B present the same DCF model, the difference between the two pertains to the ERA, which is discussed in the next section of these reasons.

The Board notes the following from YEC's evidence:

Diesel generation fuel costs at 100% LTA related to any incremental growth above GRA approved forecasts in any year are also charged to YEC under the DCF as proposed in YEC's January 31, 2014 filing, regardless as to actual diesel generation that occurs in any year. This reflects long-standing principles under the

⁴³ UCG Reply Argument, page 4.

⁴⁴ UCG Reply Argument, page 2.

⁴⁵ UCG Reply Argument, page 2.

⁴⁶ UCG Reply Argument, page 3.

⁴⁷ UCG Reply Argument, page 4.

⁴⁸ UCG Final Argument, page 6, AEY [YECL] response to YUB-YECL-1-7 (b), YEC argument, page 5 and YEC Supplemental Filing, Attachment 1, page 1-3.

DCF and YEC's prior Low Water Reserve Fund, i.e., when the DCF is activated, YEC's actual costs for diesel in any year reflect GRA approved diesel generation forecasts based on specified water forecast assumptions and not actual YEC generation.⁴⁹ [emphasis added]

The Board interprets that the above sets out how the fund operates. That is, YEC records the expected diesel costs based on long-term average (LTA) hydro availability⁵⁰. Any deviation between the expected diesel costs at LTA availability and actual diesel costs are then attributed to the DCF.

Generally, the issues brought forward by parties regarding the DCF pertain to the YECSIM model, diesel being “on the margin” and secondary sales. Regarding the latter two, YEC has provided sufficient evidence⁵¹ to convince the Board that based on current loads, expected load growth, and LTA hydro generation that there is a reasonable expectation that under these conditions that diesel or “thermal” generation will form part of baseload generation thus making the question of diesel being either “on the margin” or “off the margin” moot. Therefore, the Board does not consider diesel being “on the margin” part of the criteria for invoking the DCF. Further, regarding secondary sales, the availability of secondary sales for discrete portions of the year does not take away that over the course of the year thermal generation is required for baseload generation under LTA water conditions, not just for peaking purposes. The availability of secondary sales can represent a situation where water availability diverges from LTA. That is, there can be more hydro availability than LTA thus make secondary sales available, or there can be less hydro availability than LTA, but the fixed load profile for certain periods is such that fixed load is less than hydro availability and therefore secondary sales can be made available. Thus the availability of secondary sales does not determine the application of the DCF.

With respect to the use of the YECSIM model, YECL has brought forward several points:

- the complexity of the YIS;
- operational decisions which can impact line losses and hence diesel requirements;⁵²
- the complexity of the YIS environment and the ability to isolate a single variable such as water flow appears unrealistic⁵³; and
- it is more efficient to test forecast to actual results versus testing the accuracy of a complex model.⁵⁴

⁴⁹ YEC Supplemental Filing (June 30, 2014), Attachment 1, page 1-3.

⁵⁰ LTA is adjusted for Fish Lake Hydro and forecast Wind generation.

⁵¹ See for example YEC application, Appendix 1.1 Pages 1.1-5 to 1.1-6, Attachment 1.1 page A1.1-9 to A1.1-10 and pages 1.1-11 to 1.1-15

⁵² AEY [YECL] Final Argument, paragraph 14.

⁵³ AEY [YECL] Final Argument, paragraph 14.

⁵⁴ AEY [YECL] Final Argument, paragraph 26.

YECL further stated:

YEC's proposed DCF mechanism, however, is contrary to these basic principles of a deferral account. It utilizes the overly complex, opaque, untestable YECSIM model to not only forecast diesel volumes for the purposes of setting YEC's rates, but it is also uses the YECSIM model to calculate the "expected actual" diesel volume amount, which the forecast is trued up to, for the purposes of determining the amount to credit to the DCF.⁵⁵

YECL further stated that due to its proprietary nature, YECSIM cannot be independently tested or retrospectively verified⁵⁶ and concluded by saying:

ATCO Electric Yukon [YECL] continues to have grave doubts that any model, no matter how sophisticated or expensive, could be designed to accurately isolate the impact of water and wind variability from all of the numerous other factors that can affect diesel consumption.⁵⁷

UCG echoed many of the points made by YECL and in addition requested independent verification of the model.

YEC responded to the YECL and UCG comments by stating this argument was without merit, in that it fails to recognize the specific basis upon which the Board approved current rates as well as essential features of any DCF. Therefore, it provided no basis for concluding that the DCF is no longer relevant or appropriate⁵⁸ and that DCF mechanisms, as approved in the past as well as proposed today, must rely on an "expected diesel generation" amount based on either an assumption or a model's analysis of LTA hydro generation.⁵⁹

YEC added:

Yukon Energy's [YEC's] submission is that discontinuing a DCF based on forecast LTA water conditions would increase rate instability, mask rather than display the expected long-term cost of power, and frustrate rather than facilitate intergenerational equity and fair treatment related to the benefits provided by hydro generation over its long-term economic life.⁶⁰

Regarding the testing of the YECSIM model as noted earlier in this decision, YEC responded that there was no merit or relevance to suggestions that YECSIM is inaccurate, that YECSIM was designed by experts and custom made for the operation of the YEC

⁵⁵ AEY [YECL] Final Argument, paragraph 27.

⁵⁶ AEY [YECL] Final Argument, paragraph 30.

⁵⁷ AEY [YECL] Reply Argument, paragraph 10.

⁵⁸ YEC Reply Argument, page 4.

⁵⁹ YEC Reply Argument, page 4.

⁶⁰ YEC Reply Argument, page 5.

power system, that YECSIM was not designed to replicate the past and that a true-up to actual results has no relevance to the past or current DCF mechanism.⁶¹ In addition YEC further noted that in the past, and in the current DCF proposal, actual diesel generation for DCF determination is not adjusted for changes from GRA approved load or generation forecasts due to changes in industrial loads, load shape over the year, or overall system losses, and therefore each of these factors can affect DCF results — a point which has nothing to do with YECSIM per se, and which in no way invalidates past or proposed DCF mechanisms.⁶²

When the Board considers the two proposed models (DCF and DDA), both have a forecast element⁶³ in terms of diesel costs and both review those forecasts versus either actual results or adjusted actual results. The Board has previously accepted LTA hydro generation as the basis for YEC GRA forecasts⁶⁴. The 2012-13 LTA forecast was provided by means of YEC's YECSIM model and was not contested at that time. Moreover, no evidence has been presented in this proceeding that the YECSIM model does not operate as it is intended, or that there would be any harm to customers if the model is used in a consistent fashion for DCF purposes. The evidence of YEC is that the fund is held in "trust" for customers.

However, if YEC is to continue to use the YECSIM model for forecasting, it has to make the model and its results available for testing because as a public utility its forecasts and rates proposals that are based on its forecasts are subject to testing by interveners and the Board. Providing forecasts which can be tested is essential in setting rates.

Therefore, although the Board has noted the other parties concerns regarding the YECSIM model, and is aware that the YECSIM model has not been tested before the Board⁶⁵, the Board accepts the DCF as proposed by YEC because it is a fund for customers to smooth rate impacts for those occasions when hydro generation is less than LTA or to build up the fund when hydro generation is greater than LTA. The Board approves the DCF as proposed by YEC. However, the Board directs that the DCF fund is to be used only for variations from LTA water availability. Any application to utilize the fund in some other fashion will require the closing of the fund, the refunding of any balances to customers, and the direction for YEC to use short-term forecasts for its hydro generation for future GRAs.

In terms of "caps" for the DCF, the Board is of the view that the +/- \$2-million level proposed by YECL is too low and would require frequent rider applications before the Board. The +/- \$5-million level as proposed by UCG would have minimal impact in the

⁶¹ YEC Reply Argument, page 15.

⁶² YEC Reply Argument, page 15.

⁶³ For YEC, please see the overview of the DCF in this Appendix A taken from YEC's 2012 General Rate Application, Transcript Volume 3, November 14, 2012, pages 573-574. For YECL, from the DDA section later in this Appendix, at page 7 of the AEY [YECL] Application, the first step is to "Determine the diesel revenues recovered by YEC rates" is based on forecast.

⁶⁴ Board Order 2013-01, Appendix A: Reasons for Decision, paragraph 60.

⁶⁵ The results of the model have been tested, but the model itself has not been tested before the Board.

case of a severe drought. Thus, the Board accepts the level of +/- \$8 million as proposed by YEC as an acceptable balance between frequency of rider applications and ability to handle material (drought) changes in hydro availability.

YEC is to reflect the result of this decision in its compliance filing to this decision. In the compliance filing, YEC is to provide an updated balance for the DCF and include any actions to be undertaken regarding that balance if necessary.

To summarize, secondary sales or diesel being “on the margin” are not hurdles to be overcome before the DCF is applied. The Board accepts there is sufficient load on the system for diesel to form part of baseload generation and therefore to apply the DCF.

Whatever model YEC uses to determine LTA hydro generation, DCF calculations or other forecast process, that model and its results, or other forecast process must be made available for testing by the Board and interveners.

The DCF is to be used for variations in LTA hydro availability. Any application of the DCF outside of this intended use may result in the cessation of the DCF, the dispensation of any balance in the DCF, and the use of short-term forecasts for hydro generation in future GRAs.

The DCF will have a cap of +/- \$8 million as proposed by YEC. If the balance in the DCF falls out of the +/- \$8 million range, YEC shall make an application to the Board to dispense with the balance that is outside of that range within 60 days of the outside-the-range occurrence.

2.2 ENERGY RECONCILIATION ADJUSTMENT

YEC describes the Energy Reconciliation Adjustment (ERA) as:

... an element of Rate Schedule 42 Wholesale Primary (YEC). The ERA determines how Yukon Energy’s annual diesel cost variances due solely to variances from YUB approved GRA wholesale forecasts are to be reflected in Yukon Energy’s rate charged to Yukon Electrical. Yukon Energy’s diesel cost impacts included in the ERA are determined after the Diesel Contingency Fund (DCF), and therefore exclude diesel generation impacts related to current water conditions.

The ERA addresses the material gap that exists between the average wholesale energy rate that YEC charges YECL under Rate Schedule 42 and the incremental cost of diesel incurred by YEC when diesel generation changes occur in response to changes in YECL’s wholesale purchases. The ERA is required to comply with OIC direction that the YEC wholesale rate charged to YECL include appropriate provisions to ensure that YEC recovers its costs. (footnotes omitted)⁶⁶

⁶⁶ YEC Application, Appendix 2, page 2-1.

1 **TOPIC:** **Stabilization Mechanism**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-2, PDF page 30

4
5 **QUOTE:** An initial thermal cost or contingency fund account mechanism (i.e.,
6 the Low Water Reserve Fund, or “LWRF”) to address water-based
7 variances from thermal generation forecasts was established in the
8 early 1990s, when YEC relied upon short-term hydro generation
9 forecasts for GRA purposes. The Board at that time noted concerns
10 about lack of rate stability with use of short-term versus LTA hydro
11 generation forecasts for GRA purposes. ... DCF was approved by
12 the Board to replace the LWRF as the thermal cost or contingency
13 fund account mechanism to address thermal generation cost
14 variances from GRA approved LTA forecasts and to smooth rate
15 cost fluctuations due to water level divergence from average.
16 (Emphasis added)
17 ...
18 In 1996/97, after the Faro Mine resumed operations, LTA hydro
19 generation forecasts were adopted for GRA purposes and the DCF was
20 approved by the Board to replace the LWRF as the thermal cost or
21 contingency fund account mechanism to address thermal generation
22 cost variances from GRA approved LTA forecasts and to smooth rate
23 cost fluctuations due to water level divergence from average.

24
25 **PREAMBLE:**

26
27 Clarification is needed regarding the change from using LTA hydro generation
28 forecasts to ST hydro generation forecasts and back to the current LTA hydro
29 generation forecasts.

30
31 **QUESTION:**

- 32
33 a) Please provide a copy of reasons of the Board or a Board Order in which the
34 Board accepted the use of short-term versus LTA hydro generation forecasts
35 for GRA purposes.
36
37 b) Has YEC continuously used LTA for hydro generation since 1996/97? Please

1 explain.

2
3 c) Please provide the reasons of the Board or a Board Order in which the Board
4 accepted LTA hydro generation forecasts from the 1996/97 GRA.

5
6 d) With respect to the DCF that was part of the 1996-97 GRA,

7 i. Please provide details as to how the DCF operated, including sample
8 numerical calculations of how determinations were made to either pay
9 or withdraw funds from the account.

10 ii. How were water level divergences determined?
11

12 **ANSWER:**

13
14 **(a)**

15
16 YUB-YEC-2-3 (a) - Attachment 1 provides the relevant excerpt from the Yukon Energy
17 1991/92 GRA seeking approval of revenue requirements and rates, as well as the Low
18 Water Reserve Fund (LWRF), using what today is in effect considered as a short term
19 hydro generation forecast [i.e., the forecast was based on the level of Aishihik Lake at the
20 time the GRA forecast was prepared, and long term average inflows thereafter]. At that
21 time, Yukon Energy did not provide any option or assessment regarding potential use of
22 long-term average hydro generation for the GRA or the LWRF, i.e., the Board was not
23 asked in the 1991/92 GRA to consider short-term versus LTA hydro generation forecasts
24 for GRA purposes.

25 YUB-YEC-2-3 (a) - Attachment 2 provides the relevant excerpt of Order 1992-1 approving
26 the short-term hydro forecasts and the Low Water Reserve Fund as applied for in the
27 1991/92 GRA.

28 It is noted that the Board in Order 1992-1 indicated concern that not using a long term
29 average hydro generation forecast (which would in effect include LTA assessment of
30 Aishihik reservoir levels) may result in rate instability. While the Board in Order 1992-1
31 accepted the short term hydro generation forecast provided by Yukon Energy in that GRA,
32 it directed Yukon Energy to present evidence related to the advantages and
33 disadvantages of using current water levels as compared to long term average hydro
34 generation at its next GRA¹.

¹ See Order 1991-2, page 52.

1 (b)

2
3 YEC has not continuously used LTA for hydro generation for GRA purposes since
4 1996/97, in the sense that the DCF was effectively suspended from 1998 until 2012.

5 The Faro mine closed permanently in 1998, subsequent to the 1996/97 GRA, leaving a
6 material surplus of hydro generation on the WAF system. Consequently, the impact of
7 water flow variations on Yukon Energy diesel fuel generation costs was only relevant in
8 the case of an extreme drought. The DCF and ERA also became effectively inactive over
9 this period as diesel was not “on the margin” [i.e., the Faro mine had closed and there was
10 a material hydro surplus].² In these circumstances, LTA hydro generation forecasts were
11 not relevant for the purpose of determining forecast diesel generation costs in rates; and
12 rates for the 2005 Required Revenues and Related Matters proceeding and the 2008/09
13 GRA did not include diesel generation requirements based on LTA hydro generation
14 forecasts.

15 Between 1998 and 2008, the existing diesel infrastructure was utilized primarily as reserve
16 capacity to meet peak or short-term emergencies. The 2008/09 GRA noted that the DCF
17 would not be advanced to the “diesel on the margin” mode until such time as the system
18 had firm loads that exceeded the LTA capability of the system over the course of a long
19 period (many months to years). However, it was also noted that the DCF could be required
20 in the test years in the event of a drought.³

21 The 2012/13 GRA Application noted that diesel generation had increased materially
22 relative to the approved 2009 GRA forecast due to load growth and reduced surplus hydro
23 generation. Further, ongoing non-industrial load growth and connection of the new
24 industrial loads to the grid had reduced surplus hydro available for secondary sales over
25 this period; and secondary sales had been interrupted on a sustained basis since
26 September 2010 and were not forecast to be available during the 2012/13 test years. In
27 these circumstances Yukon Energy proposed to transition towards using long term
28 average hydro generation forecasts in the 2012/13 GRA and to update and re-activate
29 both the DCF and the ERA.

² Under the DCF fund rules that previously existed, when diesel was not on the margin, the account could in certain circumstances be used to pay for the costs of generation using diesel (when monthly diesel generation exceeded 250 MW.h notwithstanding that it is not required to meet base loads under normal flows, i.e., in the case of a drought that requires diesel generation even though hydro should be able to fully satisfy the system outside of limited peaking use).

³ 2008/09 GRA, Tab 3, page 3-22.

1 Board Order 2013-01 directed Yukon Energy to set rates once again based on 100% long
2 term average hydro forecasts, starting with 2012.

3
4 **(c)**

5
6 The 1996/97 GRA Negotiated Settlement established the Diesel Contingency Fund which
7 replaced the Rate Stabilization Fund as proposed in the 1996/97 GRA, and which was to
8 “operate to smooth customer rate changes and offset forecast diesel costs.”

9 The Negotiated Settlement established that “rates and the fund will be determined using
10 the long-term average water expected to be available for generation (105 + 246 GWh)”;
11 and “the fund is only to be used for the purposes of stabilizing customer rates and
12 offsetting diesel generation cost estimates and the fund is not to be accessed for other
13 reasons including government subsidy of rates.”⁴

14 The Negotiated Settlement was approved by the Board in Order 1996-7. The Board noted
15 that it was satisfied that the settlement agreement was in the best interests of the public
16 and accepted the settlement package as presented. [See YUB-YEC-2-3(c) – Attachment
17 1 which provides Order 1996-7 and includes materials relevant to the Negotiated
18 Settlement.]

19 Further context leading up to the 1996/97 GRA and the adoption of the DCF and LTA
20 hydro generation as part of the Negotiation Settlement is provided as follows:

- 21 • Prior to 1996/97 GRA, Board Order 1992-1 had approved a low water reserve
22 based on short term hydro forecasts that considered Aishihik Lake levels at the
23 time the forecast was prepared.
- 24 • In the 1991-92 GRA, the Board indicated concern that the [short term hydro
25 forecast] approach adopted by the utilities would result in greater rate instability,
26 and directed the utilities to provide an assessment of the advantages and
27 disadvantages of using current water levels as compared to long term average
28 hydro generation at the next GRA. [See Attachment 2 to YUB-YEC-2-3(a) for the
29 relevant excerpt of Order 1992-1; the response to the Board’s directive from Order
30 1992-1 is provided as YUB-YEC-2-2(c) Attachment 2.]

⁴ See March 11, 1996 Letter from Bill Grant to Bill Byers regarding Proposed Settlement of Issues Concerning the Revenue Requirement and Rate Design Application of YEC and YECL attached to Order 1996-7.

- 1 • The utilities responded to this direction in the 1993/94 GRA noting that the use of
2 LTA hydro generation would remove instability in rates due to Aishihik Lake level
3 fluctuation, but would have achieved this result in 1992 by requiring higher
4 consumer rates and greater year end reserve adjustments. The Companies in the
5 1993/94 GRA maintained the short-term forecast methodology [based on current
6 Aishihik Lake water levels] for the purpose of determining 1993/94 rates.⁵
- 7 • As part of the 1996/97 GRA the Companies proposed shifting to LTA forecasts
8 from short-term forecasts, based on Aishihik Lake levels at the time of filing, noting
9 that “very significant variance in water flows over the past three to four years has
10 led the Companies to reassess their position with respect to the use of the low
11 water reserve fund.” Specifically, it was noted that high water flow years on the
12 Aishihik system in the late 1980’s and early 1990’s had been replaced with drought
13 conditions; that Aishihik Lake inflows in 1994 were only 35% of long term average
14 [translating to a 68 GWh loss of generation]; and that total water flows at Aishihik
15 in 1995 were expected to be 52% of LTA. The Companies noted that potentially
16 large fluctuations in rates caused by variances in available water flows warranted
17 moving to LTA for determining rates, and proposed to use the LWRF as a Rate
18 Stabilization Fund to “absorb annual fluctuations in available water resources
19 without resorting to massive rate fluctuations from year to year.”
- 20 • The low water reserve/ rate stabilization fund included in the 1996/97 GRA filing
21 by the Companies was addressed as part of a Negotiated Settlement. As part of
22 the terms of the Negotiated Settlement, the parties agreed that the “Diesel
23 Contingency Fund” would replace the proposed Rate Stabilization Fund, and
24 “operate to smooth customer rate changes and offset forecast diesel costs.”
25 Further, “rates and the fund will be determined using the long-term average water
26 expected to be available for generation (105 + 246 GWh)”; and “the fund is only to
27 be used for the purposes of stabilizing customer rates and offsetting diesel
28 generation cost estimates and the fund is not to be accessed for other reasons
29 including government subsidy of rates.”⁶

⁵ It was clarified that each hydro forecast to that point reflected the lake level then existing at Aishihik Lake, assumed long term average water inflows for the future and that whatever storage may existing at Aishihik Lake will be used within the limits permitted by the water license and YEC’s water management policy.

⁶ See March 11, 1996 Letter from Bill Grant to Bill Byers regarding Proposed Settlement of Issues Concerning the Revenue requirement and Rate Design Application of YEC and YECL attached to Order 1996-7.

- In Order 1996-7 the Board noted that it was satisfied that the settlement agreement was in the best interests of the public and accepted the settlement package as presented. [See YUB-YEC-2-3(c) – Attachment 1 which provides Order 1996-7.]

(d)

The Terms of the 1996/97 Negotiated Settlement approved by Board Order 1996-6 provided for the creation of the Diesel Contingency Fund (DCF). The March 11, 1996 letter recording the settlements is provided as YUB-YEC-2-3(d) - Attachment 1.

Historically, the DCF operated to smooth customer rate changes and offset forecast diesel cost variances due to variances in hydro generation capability. The DCF operated on the same basis as the earlier Low Water Reserve Fund (LWRF) in place from 1991 through 1995, except for the material differences specific in the 1996/97 Settlement Agreement. (YUB-YEC-2-3(d) - Attachment 2 and YUB-YEC-2-3(d) - Attachment 3 to this response provide two letters filed with the Board June 2, 1999 and October 7, 1999 which detail how the fund was to operate. These letters addressed issues arising for Board approval of annual DCF filings for 1996 through 1998, and include review of issues specific to that time period, e.g., impacts of the fire at YEC's Whitehorse facilities and impacts of a drought.)

- The DCF was intended to offset diesel generation cost changes for the WAF system caused solely by variances from long term average levels of WAF system hydro and wind generation. As documented in YUB-YEC-2-3(d) - Attachment 2, long term average generation was set as follows, based on the best information then available:
 - o YEC's hydro for WAF at 351 GW.h/yr. (105 GW.h at Aishihik and 246 GW.h at Whitehorse);
 - o YEC wind for WAF at 0.3 GW.h/yr.; and
 - o YECL Fish Lake hydro at 10 GW.h/yr.
- In accordance with defined procedures [reviewed in YUB-YEC-2-3(d) Attachments 2 and 3], the DCF Report set out both actual and forecast generation numbers for the purpose of each year's calculations.
- The forecast generation for hydro and wind reflected the appropriate long term average levels, as confirmed in the Negotiated Settlement Agreement for the 1996/97 GRA.

- 1 o The WAF diesel generation costs per kWh were based on the GRA forecast
2 (standard efficiency for diesel generation unit use of fuel, YEC average
3 WAF diesel fuel price forecasts, and variable O&M diesel generation costs
4 per kWh, each as approved in the GRA).

5 The DCF fund operated outside of rate base with annual reporting to the Board to detail
6 additions and deletions to the fund. The Board directed the Companies on the additions
7 and deletions to the fund. Prior to the re-activation of the DCF in 2012/13 GRA,
8 additions/deletions to the fund were last addressed in Order 1999-3 [see YUB-YEC-2-3(d)
9 - Attachment 4).

10 A key element of the DCF operation as approved in the 1996/97 GRA was determining
11 when diesel generation was “on the margin” (defined as diesel being used to meet long-
12 term firm energy requirements of the WAF system, not just periodic peaking
13 requirements). Diesel was not considered to be “on the margin” when the Faro mine was
14 closed. On this basis, diesel was determined under the DCF to not be on the margin from
15 June 1 to October 31, 1997, and after January 31, 1998 (i.e., after the Faro mine closed
16 permanently). The requirement to reactivate the DCF to address growing thermal
17 requirements on the Yukon Integrated System did not occur until the 2012/13 GRA.

18 Aside from interest payments or charges, the DCF operation as approved from the
19 1996/97 GRA could be either credited or debited each month for one of two reasons:

- 20 • **When diesel was “on the margin”**, the account stabilized the diesel costs related
21 to water flow variations. In these situations (i.e., with diesel “on the margin”), when
22 hydro varied positive or negative from the long term average forecast, that variance
23 was met effectively 1 for 1 with changes in diesel generation compared to what
24 would have occurred had the hydro variance not occurred. This happened, for
25 example, in the periods of 1996-1998 when the Faro mine was operating, and was
26 last triggered for January 1998.
- 27 • **When diesel was not on the margin**, the account could in certain circumstances
28 be used to pay for the costs of baseload generation using diesel when such
29 baseload generation arose due to low water conditions. This happened in a
30 number of months during 1999, when diesel was not considered to be on the
31 margin (due to low grid load levels hydro should have been able to supply all base
32 load requirements); however, extremely low water led to the need for baseload
33 diesel generation.

1 In practice, when diesel was not on the margin, the distinction between normal
2 “peaking” operation and true baseload diesel was set at 250 MW.h/month for
3 calculation purposes⁷.

4 In addition, diesel generation from forest fire impacts in July 1998 and from the
5 October 1997 fire impacts at the YEC Whitehorse Rapids hydro facility were
6 removed from the DCF in recognition that these requirements were not related to
7 water conditions (see YUB-YEC-2-3(d) - Attachment 2).

8 Based on the DCF operation example provided in YUB-YEC-2-3(d) - Attachment 3, the
9 following sample numerical calculations show how determinations were made to either
10 pay or withdraw funds from the DCF related to YEC operations (ignores wind and Fish
11 Lake hydro), and the critical importance of the “expected diesel generation” concept in
12 order to isolate water-related variances from load-related variances:

- 13 • Example 1: Diesel on the Margin (Faro mine operating)
 - 14 o Assume:
 - 15 ▪ Forecast 50 GW.h total WAF load, with 10 GW.h from diesel based
 - 16 on 40 GW.h average hydro forecast at this load.
 - 17 ▪ Actual 60 GW.h total WAF load with 20 GW.h from diesel.
 - 18 o DCF and LWRF determinations:
 - 19 ▪ “Expected diesel generation” = actual load less approved long term
 - 20 average (LTA) hydro generation amount = 60-40 = 20 GW.h
 - 21 ▪ Accordingly, actual diesel=expected diesel and no impact on DCF.
 - 22 ▪ Same result if actual load was 40 GW.h and diesel was “0”.
- 23 • Example 2: Diesel on the Margin (Faro mine operating)
 - 24 o Assume:
 - 25 ▪ Same forecast as above.
 - 26 ▪ Actual 60 GW.h total WAF load with 15 GW.h from diesel.
 - 27 o DCF and LWRF determinations:

⁷ In cases where diesel generation exceeded 250 MW.h but the generation was for peaking requirements, the DCF was not charged – for example, December 2008.

- 1 ▪ “Expected diesel generation” = actual load less approved long term
2 average (LTA) hydro generation amount = $60 - 40 = 20$ GW.h.
- 3 ▪ Diesel savings = expected less actual = $20 - 15 = 5$ GW.h due to
4 water.
- 5 ▪ DCF then be credited for value of 5 GW.h of diesel generation cost
6 savings due to water variance from LTA.
- 7 • Example 3: Diesel on the Margin (Faro mine operating)
 - 8 o Assume:
 - 9 ▪ Same forecast as above.
 - 10 ▪ Actual 60 GW.h total WAF load with 25 GW.h from diesel.
 - 11 o DCF and LWRF determinations:
 - 12 ▪ “Expected diesel generation” = actual load less approved long term
13 average (LTA) hydro generation amount = $60 - 40 = 20$ GW.h.
 - 14 ▪ Diesel savings due to water = expected less actual = $20 - 25 = -5$
15 GW.h.
 - 16 ▪ DCF then be charged (drawn down) for value of 5 GW.h of diesel
17 generation added costs due to water variance from LTA.
- 18 • Example 4: Diesel Not on the Margin (Faro mine closed)
 - 19 o DCF now assumes expected diesel at “0” (based on ability to meet WAF
20 loads with hydro at LTA and no diesel).
 - 21 ▪ Experience shows some minor level of diesel still needed for
22 peaking, voltage stability or other purposes not affected by
23 variances from forecast hydro generation capability.
 - 24 ▪ YUB-YEC-2-3(d) - Attachments 2 and 3 note that, to address this
25 factor, DCF was not activated in any month when actual diesel
26 generation not exceed 250 MW.h.
 - 27 o However, DCF will apply if diesel becomes required due to drought (low
28 water conditions).
 - 29 ▪ During winter of 1998/99, with Faro mine closed, actual low water
30 conditions did result in baseload diesel being required, and the DCF
31 was used in 1999 to address this variance.

o Numerical example:

- Assume forecast as per Example 1 with total load at 50 GW.h, LTA hydro at 40 GW.h capability if load exists, and diesel at 10 GW.h.
- Assume actual as follows:
 - Actual load at 35 GW.h due to mine closure; means expected diesel = 0.
 - Actual diesel at 5 GW.h (means actual hydro at 30 GW.h).
- Diesel cost due to water = Expected diesel less actual diesel = 0-5=-5 GW.h.
- DCF then be charged (drawn down) for value of 5 GW.h of diesel generation added costs due to water variance from LTA.

The above examples show how water level divergences were determined. For any given grid load, the “expected diesel” was equal to what remained after deducting the approved hydro forecast for the grid load (for the DCF, this was LTA hydro forecast) – and water level divergence equaled expected diesel less actual diesel.

- The 1996/97 approved DCF was relatively simple to implement when the Faro mine was operating, i.e., LTA hydro was assumed at one specific level (by month) regardless of actual grid load, and expected diesel then equaled actual load less expected hydro generation.
- When the Faro mine was not operating, expected diesel was set at zero. In the event that material actual diesel occurred, assessments were made (with specified assumptions) to determine what portion (if any) of this diesel was due to low water conditions.

2-24

As at December 31, 1990, YEC remained in a strong financial position with equity in excess of 40 per cent of total capital.

2.8 Financial Policies

YEC has been directed in Order-in-Council 1991/62 to earn a rate of return equivalent to a normal commercial rate of return less one half of one per cent. YEC has determined that the rate of return requested by YECL represents a fair and reasonable normal commercial rate of return, and YEC will rely on the testimony of YECL with respect to the normal commercial rate of return submitted in the GRA for 1991 and 1992. In accordance with the directive, YEC has set its rate of return in this Application at one half of one per cent less than the rate requested by YECL.

As mentioned above, YEC was formed with a debt equity ratio of 60:40. A recent review by YEC indicates that a higher target ratio of 50:50 may be appropriate to facilitate future cost effective financing of major new long term debt needed to develop major new transmission or hydro generation projects. The GRA has been prepared, however, assuming YEC's existing general debt equity ratio of approximately 60:40. YEC will retain all earnings other than those required to fund the rate relief program (as described in more detail below).

YEC's contingency reserve remains, from the previous Application, as an unfunded reserve for low water (\$2.0 million) and a reserve for uninsured losses (\$250,000). This reserve is treated as no-cost capital in the GRA,

2-25

reflecting its use to fund YEC's rate base. It is the intention of YEC that this reserve be treated as a customer operating reserve rather than as part of Shareholders' equity, with appropriations or withdrawals in future being reflected in the statement of income prior to determination of net income. The following ground rules are proposed with respect to the future use of the \$2 million contingency reserve related to water-flow generation variances:

- a) YEC will establish standards, from time to time, for hydraulic generation from its system based upon long term averages of available water as well as forecasts for load requirements. At the present time, YEC's hydraulic generating stations on the WAF system are estimated to have an energy capability as follows:

	1991	1992	
Whitehorse	250	250	GWh/yr.
Aishihik	134	107	GWh/yr.

- b) In years when water availability deviates from long term averages and causes actual hydraulic generation to differ from YEC's projected generation, the resulting variance in diesel generation costs (i.e. the variation in such costs relative to forecasts, due solely to the impact of water availability fluctuation on hydraulic generation capability) would be treated as follows:

- I. Appropriations would be made from YEC income to the extent that YEC diesel generation costs in any year are below forecast levels due to above average hydraulic generation capability, and such appropriations would be added to the above contingency

2-26

reserve(subject to the condition that the reserve not exceed a specified maximum level as set out below).

II. Withdrawals from the above contingency reserve would be added to YEC income to the extent that YEC diesel generation costs exceed forecast levels due to below average hydraulic generation capability.

- c. It is proposed that the maximum contingency reserve amount for the above purposes reflect a reasonable estimate of YEC losses which could result from replacing hydraulic generation with diesel generation in low water years.

2.9 Bill Relief Program

As required by regulations outlined in the Order-in-Council 1987/72, bill or rate relief is funded from YEC's retained earnings. During the period of the GRA it is expected that the rate relief will amount to:

1991	<u>\$193,538</u>
1992	<u>\$467,157</u>

As outlined in the previous GRA, Yukon government policy has identified the following levels as being eligible for rate equalization and rate relief:

- a. Residential non-government accounts, customer charge and consumption up to 1,000 kWh/month.

YUKON UTILITIES BOARD
DECISION 1992-1

PAGE 47.

these two positions to be \$100,000 per year and will deal with this cost as part of the Company's DSM expenditures.

The Board considers that at this time it would be inappropriate to include any costs relating to DSM expenditures in YEC's 1991 and 1992 revenue requirement. The Board directs the Company to provide detailed support for its 1991 DSM programs and its planned 1992 DSM programs in the upcoming capital hearing.

In particular the Board directs the Company to provide detailed program evaluations and cost benefit studies together with a detailed description of the results of similar programs carried out in other jurisdictions.

The Board directs that all DSM expenditures for 1991 and 1992 be placed in CWIP. Accordingly, the Board has reduced the operating expenses by \$150,000 for each of the test years 1991 and 1992. The year end 1992 rate base has also been reduced by \$750,000.

7. LOW WATER RESERVE

At December 31, 1990 there was a balance of \$2 million in the Company's low water reserve. As explained in Decision 1989-4, the \$2 million reserve was established out of retained earnings to protect against increased costs to produce electricity by diesel generation at times of low water conditions and shutdowns of hydro facilities.

YUKON UTILITIES BOARD
DECISION 1992-1

PAGE 48.

In the current application YEC has proposed the following with respect to the low water reserve:

"I. Appropriations would be made from YEC income to the extent that YEC diesel generation costs in any year are below forecast levels due to above average hydraulic generation capability, and such appropriations would be added to the above contingency reserve (subject to the condition that the reserve not exceed a specified maximum level as set out below).

II. Withdrawals from the above contingency reserve would be added to YEC income to the extent that YEC diesel generation costs exceed forecast levels due to below average hydraulic generation capability." (YEC's Application, Page 2-25)

YEC is also proposing:

"... that the maximum contingency reserve amount for the above purposes reflect a reasonable estimate of YEC losses which could result from replacing hydraulic generation with diesel generation in low water years." (YEC's Application, Page 2-26)

In response to an information request the Company indicated that it was proposing a maximum contingency reserve of \$4 million.

The response also states that:

"Variations to the reserve will not normally be factored into General Rate Applications as the GRA is based upon average water flows for prospective test years.

The reserve will be affected only when hydraulic generation varies from these amounts due to fluctuations in water flow. This will be done on a retrospective basis after the actual results for the operating year have been taken into consideration. The debit or credit to the reserve will be utilized in the calculation of net income for the year. For

YUKON UTILITIES BOARD
DECISION 1992-1

PAGE 49.

example, if hydraulic generation exceeds the forecast due to higher than expected water flows, then the savings in diesel will be credited to the reserve. If hydraulic generation is less than the forecast due to lower than expected water flows, then the additional costs incurred making up the shortfall with diesel will be debited to the reserve and credited to expense."
(WHSE-YEC-10)

Company witnesses further explained how the low water financial reserve will work to stabilize rates in Yukon.

"I think that's the important thing to focus on from the customers' point of view, is that it [the low water financial reserve] takes any excess earnings which result from a factor such as rainfall, and makes sure that the customers eventually get it.

As I stated before, in the case of a low water year, we would be inclined, I think [in the absence of such a reserve], to come back to the Board for higher rates in a year because the potential impact is quite large."
(Tr.591)

On the basis of the evidence adduced during the hearing, it is the Board's understanding that the low water reserve will be implemented by the Company in the following manner:

- (1) The Company will determine the level of the lake at the time the forecast is prepared.
- (2) The Company will forecast average water inflows during the year.
- (3) Based on steps (1) and (2) the Company will forecast the amount of hydro generation and thus the required amount of diesel generation.

YUKON UTILITIES BOARD
DECISION 1992-1

PAGE 50.

- (4) At the end of the year the Company will determine if the forecast diesel generation differed from actual experience due to water flows and if so the reserve will be increased or decreased accordingly.

Based on the above procedures it is the Board's understanding that no direct charge will be included in the forecast revenue requirement for the low water reserve. Rather, if the Company over earns in a year because the actual diesel generation is less than the forecast diesel generation due to higher than forecast water flows, the reserve would be increased to the extent of the difference between forecast and actual diesel generation up to a maximum of \$4 million. Similarly, if the Company under earns in a year because actual diesel generation exceeds forecast diesel generation due to lower than forecast water flows, the reserve would be decreased.

In its October 1991 update YEC stated:

"The proposed GRA adjustments do not include any additions in 1992 to YEC's low water financial reserve, thereby facilitating the minimum 1992 rate increase; as a result, the 1993 overall retail rate increase will be increased by approximately six percentage points above the level otherwise required if 1992 rates had reflected the maximum potential 1992 increase (\$2.0 million) in YEC's financial reserve." (October 1991 Adjustments, Page 4)

The Board's understanding of this statement is that rates would be impacted in the following manner:

YUKON UTILITIES BOARD
DECISION 1992-1

PAGE 51.

- (1) The 1992 revenue requirement as initially filed was based on average hydro and diesel generation.
- (2) The 1992 amended revenue requirement was based on above average hydro generation and below average diesel generation resulting in lower rates than would have prevailed if average hydro and diesel generation had been used.
- (3) If, in 1993, water flows are such that hydro generation is average resulting in average diesel generation, an increase in rates above 1992 levels will be required.

In YEC's argument it requested that the Board approve the following with respect to the low water reserve:

- "(a) Whether this reserve should be established in the manner proposed by YEC, including the various ground rules set out by YEC in the evidence?
- (b) If the Board approves the reserve, is the proposed \$4.0 million approved as the maximum amount applicable at this time for the reserve?
- (c) If the Board approves the above proposals, is the proposed adjustment to YEC's initial Application (the October 21, 1991 update) accepted with respect to Aishihik generation for the test year 1992, i.e., the increase in forecast Aishihik generation from 107 to 150 GWh for that test year based solely on higher-than-expected water availability which occurred after filing of the initial Application in June 1991?"
(Page 51)

YUKON UTILITIES BOARD
DECISION 1992-1

PAGE 52.

initial Application in June 1991?"
(Page 51)

The Board is concerned that the use of the "level of the lake at the time the (hydro) forecast is prepared" as proposed in the October 1991 update rather than using a hydro generation forecast based upon long term average hydro generation may lead to rate instability.

For the purpose of this Decision the Board accepts the updated hydro generation forecast for 1992. At the time of the next general rate application the Board expects the Company to present evidence relating to the advantages and disadvantages of using current water levels as compared to long term average hydro generation. Also for the purpose of this Decision the Board will accept the procedure for the low water reserve as described at Pages 2-25 and 2-26 of the Company's Application and the \$4 million maximum. However, the Board anticipates that all matters relating to the low water reserve will need to be re-examined at the next general rate application.

8. RIDER F - FUEL ADJUSTMENT RIDER

YEC'S evidence indicated that at the end of 1990 fuel costs exceeding those included in rates (unfavourable variance) of \$544,190 had not been collected from its customers. The unfavourable variance was included as a deferred charge on YEC's 1990 balance sheet.

1996-7

**AN ORDER IN THE MATTER of the *Public Utilities Act*
Revised Statutes, 1986, c. 143, as amended**

and

**A Joint Application by Yukon Energy Corporation and
The Yukon Electrical Company Limited**

BEFORE: B. Morris, Chair; and)
G. Duncan, Acting Vice-Chair) June 11, 1996

ORDER 1996 - 7

1.0 APPLICATION

On November 17, 1995 Yukon Energy Corporation and Yukon Electrical Company Limited ("YEC/YECL, the Companies") filed with the Yukon Utilities Board ("Board"), pursuant to the *Public Utilities Act* ("Act") and Order-In-Council 1995/90, an Application requesting an Order granting new rates, effective with consumption January 1, 1996 with a further increase on January 1, 1997.

The General Rate Application also proposed changes in rate design, with average increases of 18 percent to the Industrial class, 4 percent to the Government Residential class, 12 percent decreases to the General Service non-government classes, and 23 percent decreases to Street Lights rates and Rate Riders for other new mines. The Application proposed to establish a Rate Stabilization Fund, amend Electric Service Regulations and withdraw previous reporting requirements.

In accordance with Board Orders, a negotiated settlement process took place and a public hearing into the Application was held beginning on March 18, 1996 in Whitehorse, Yukon.

2.0 NEGOTIATED SETTLEMENT

2.1 Overview

As a result of the public workshops and settlement discussions held during the week of March 4, 1996 a settlement agreement was achieved with respect to numerous issues in

the Companies' Application (Exhibit 142). The settlement participants agreed with the contents and details of the Application, except for certain adjustments and the identification of specific issues which were reviewed by the Board in a public hearing.

The settlement agreement also accepted the rate design philosophy of the Companies subject to review of cost of service allocations and the appropriate revenue/cost ratios that are to be achieved by various customer classes. Although the cost of service studies in the Application were accepted by all parties for this rate-making period, the Companies agreed to provide a preliminary community-based 1995 cost of service study by July 1, 1996. (T. 49) On March 15, 1996 the Companies filed the schedules required to calculate the revised revenue requirement based on the negotiated settlement package (Exhibit 148).

2.2 Revenue Requirement Decision

The Board has a statutory responsibility to regulate in the public interest and therefore the Board cannot accept a proposed settlement unless it is persuaded that the settlement agreement is in the best interest of the public. This ultimate responsibility cannot be delegated to the Board staff or to a negotiation group. During the public hearing, the Board heard evidence and argument with respect to the Application and the negotiated settlement package, with the exception of certain cost of service arguments to be filed by March 25, 1996. (T. 145)

The Board, being satisfied that the settlement agreement was in the best interests of the public, accepted the settlement package as presented and issued Order 1996-6 which also identified the hearing costs to be included in the Companies' revenue requirement.

3.0 COST OF SERVICE ISSUES

3.1 Line Losses

In its March 25, 1996 submission (Exhibit 181), the Anvil Range Mining Corporation (ARM) states that it represents about 40% of the total Yukon electrical load and therefore there is no reason that its line losses cannot be calculated independently. The Companies argue that, since the majority of line losses occur in low voltage distribution and not high voltage transmission, the losses attributed to ARM should not be based on the Yukon average.

Rates that are designed so that a customer only pays for costs of assets directly attributable to their load are essentially a regionalizing of the rate structure. In order to regionalize ARM's rates and charge them only for the system losses caused by their load, YEC/YECL would have to perform several system load flow studies with and without their load. To eliminate a degree of uncertainty, the load flow studies would have to be done under different demand and system configurations. These studies could then form the basis for calculating the system losses attributable to ARM (station loads

would have to be added on a prorated basis). In addition, system costs would need to be analyzed to determine what proportion of costs are attributable to ARM's losses. The appropriateness of regionalizing rates in the Yukon has not been determined and this hearing did not examine any such studies. Therefore, the Board has an insufficient base to draw any conclusions regarding the impact of such rates on other customer classes. At present sections 4 and 6 of OIC 1995/90 preclude the implementation of more than one rate zone. However, this issue may require future action and the Board will consider the merits of a more detailed evaluation at a later date.

According to ARM, evidence presented at previous GRA hearings has indicated that the line losses for the Faro mine were below the Yukon average (calculated to be 6.62%, by Dr. Ileo, a consultant representing Curragh in the 1993/94 General Rate Application hearing). Since studies are currently not available, ARM concludes that the Companies are simply estimating the results without supporting backup evidence. ARM therefore requests that the Board accept the conclusion reached by Dr. Ileo or direct the Companies to perform the studies to resolve the issue.

The Companies respond that Board Decision 1993-8 considered line losses and found that line losses for industrial customers should not be adjusted at the time. In addition, the Companies state that the Board concluded that circumstances had not changed to warrant a revision to the cost of service or rate design principles from those established in the 1992 Cost of Service hearing. The Companies submit that Anvil had not provided new information to the Board which would provide a basis to review the line losses with respect to the cost of service allocators and that, based on current evidence and prior hearing information, there is no justification for the Board to conclude that the determination of line loss is "discriminatory or unfair" (Exhibit 189).

The City of Whitehorse offered the view that the bulk of the line losses occur in the low transmission system while ARM is served at high transmission voltage. In this circumstance, it considers that the increase in line losses attributed to ARM is a result of the mine being at the end of a long transmission line from the hydro generation facility (Exhibit 186).

As stated by the Companies, the line loss calculation elements are transmission, distribution and station losses and each is integral to the line loss calculation (Exhibit 153). In the original Application, the line losses were calculated to be 13.47% but a subsequent study revised the losses to 11.13%. The Companies stated that there were a number of factors that accounted for this difference:

- The transmission line distance between hydro generation (which is dispatched before diesel generation) and the Faro mine causes significant line losses;
- Line losses are reduced when the diesel units at the Faro mine are operating;
- Station service electrical heating load can be derived from hydro (when there is surplus) or waste heat from the diesel generation units;
- System modeling error occurs when yearly energy values are converted to average demand; and

- The Companies have assumed that a new 3.0 MV diesel unit (installed in 1993) will be used heavily during the test years (Exhibit 153).

The Board accepts the revised line loss calculation of 11.13% as presented by the Companies. However, this issue may require future action and the Board will consider the merits of more detailed evaluation at a later date.

3.2 Demand Allocation based on KV.A and kW

ARM's concern is that the cost of service study is based on kW's and not KV.A; that the Companies have not adjusted KV.A's in the study to reflect a power factor of about .95; and therefore the electrical demand has been over estimated resulting in additional costs assigned to ARM which are not justified (Exhibit 181).

According to the Companies, the forecast demand was converted from KV.A to kW with the appropriate power factor before costs were allocated in the cost of service study. The power factor was determined on the basis of information provided by ARM while historical information was collected from the previous mine operator. Therefore ARM has its costs allocated on the same kW basis as every other customer (Exhibit 189).

The City of Whitehorse contends that the cost of service study is consistently based on the kW unit where appropriate, therefore there is no issue (Exhibit 186).

ARM may be confused with the rate structure. The rate form with a KV.A component is intended to encourage a high power factor and does not indicate the cost allocation process. The Board finds that the correct conversion to kW has been performed to determine the appropriate allocators.

3.3 Attachment to the System of a "New" Customer or an "Old" Customer

ARM argues that it is a new company that has taken over an old mine and that the Board should not permit the mine to be burdened with specific cost allocations that applied in the past. If this is taken to be the case, the transmission line from Whitehorse to Faro in fact was not designed for ARM and is fully depreciated, therefore the rate level to ARM should reflect the current cost of the line.

The Companies argue that the vintage of the customer is irrelevant in the development of a cost of service study, stating:

"In fact this method specifically makes the vintage of (a) customer irrelevant, which combined with its stability makes the fully allocated embedded cost of service study the universal standard of fair cost allocation." (Exhibit 189)

It is the Companies' view that there have been no changes in circumstances that require a revision to the methodology from that established in the 1992 Cost of Service Report (Exhibit 189).

The City of Whitehorse states that ARM's argument is irrelevant and the mine should be treated like every other customer in the Yukon that must pay a rate based on the embedded cost of service (Exhibit 186)

The allocation of specific transmission costs to ARM conforms to similar practices in Canada. The assignment of 85% of costs of the Faro transmission line to the industrial rate class is based on usage and is not related to the status of old or new customer. In the absence of the mine load, the transmission line would not have been built. The current cost of service was prepared in accordance with the Board's recommendations in 1992 and subsequently reaffirmed in its Decision 1993-8 (Section 6.1, page 99).

The Board finds that the vintage of a customer is not currently appropriate to the development of the cost of service studies for the Yukon.

3.4 One Rate Zone, Pooling of Income Taxes and Other Costs

The Yukon has two electrical systems operating under different ownership. Each one has a different cost structure, one pays income taxes (YECL), and the other (YEC) does not. Although ARM is a customer of Yukon Energy Corporation, under the concept of tax pooling, it is responsible for taxes incurred by YECL. In ARM's opinion, the legal basis for pooling income tax costs has never been explained and the argument that the same class of customers must pay the same electrical rates whether they are customers of YEC or YECL is without foundation as YECL has no industrial customer class.

As well, according to ARM, any requirement to charge postage stamp rates does not preclude the Companies from determining the actual costs to supply each customer class, including large industrial customers such as ARM. ARM asserts that, without proper price signals, longer term strategies to develop power options cannot be developed. It argues that customers on the Whitehorse-Aishihik-Faro (WAF) system subsidize the diesel generation component of the system. The result is that the cost of diesel in outlying communities does not reflect actual costs and inhibits the development of competitive sources of alternative power generation.

ARM believes that tax revenues should be the source of funding for a social assistance policy and that two separate rate zones would eliminate the cross subsidization. The June 1985 NEB Decision indicated that there should be two separate rate zones divided between diesel and hydro (Exhibit 181).

The Companies point out that the present cost of service methodology, including the method of pooling income taxes and other costs, is the same as the method approved by the Board in the previous GRA. The Companies argue that there is no discretion provided to the Board or the Companies to decide costs that should be pooled. The rate charged by both companies, YEC and YECL should be the same and all areas of the Yukon must be pooled in determining a Yukon-wide cost of service (Exhibit 189).

The City of Whitehorse states that the Board is prevented from adopting ARM's argument under OIC 1995/90, Section 6 (1), which requires that rate levels for customers in the same class be identical across the Yukon (Exhibit 186).

The Board has a responsibility to represent all customers in all classes and cannot rely on an intervention by a single customer in any one class to adequately represent the entire class.

According to OIC 1995/90, Section 6 (1), pages 4 and 5, the following condition applies:

"The Board must ensure that the rates charged to major industrial power customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole of the Yukon as a single rate zone and the rate charged by both utilities must be the same."

Therefore, in the Board's view, the entire Yukon must be treated as one rate zone and costs must be pooled in order to develop a rate that is equal for both utilities.

3.5 Classification of Whitehorse #4

According to ARM, the classification of Whitehorse #4 to 100% energy results in an unfair burden being placed on this industrial customer. Since the hydro facility is operated for baseload it is no different than Whitehorse #1, #2 or #3. Generation is operated collectively and one unit should not be separated out. ARM states that, if conventional utility practice were applied and Whitehorse #4 were considered the same as the other units for cost allocation purposes, then there would be less cost burden transferred to the mine.

The Companies state that the rationale for building Whitehorse #4 was to replace diesel generation with lower cost hydro generation, that no extra peaking capacity was provided to the WAF system, and that the classification to 100% energy has been examined in previous hearings without a change to this current method (Exhibit 189).

In the Cost of Service Study Report, the Board recommended that, based on the available evidence the appropriate method of classifying the costs associated with Whitehorse #4 was to apply 100% to energy. The Board at that time also recommended that the Companies perform a study of Whitehorse #4 to determine the impact on the capacity of Aishihik at the system peak. The results of that study were provided to the Board in the 1993/94 GRA Volume 1, Tab 5, pages 5.2 - 12/13 (YUB - YECL - 1 - 53). The resultant study confirmed the earlier conclusions.

The Board finds that the allocation factor used is appropriate and is consistent with past practice, and is appropriate at this time. However, the Board makes no

comment on the conclusions of the Company study and will consider the issue still subject to review at a later date if circumstances change.

3.6 Classification of Other Hydro Facilities

According to the Companies, the usual practice is to classify hydro facilities as 60% energy and 40% demand and that this procedure has been followed with the exception of Whitehorse #4 which reflects the specific cost causation for this facility. The Companies submit that the current classification which was accepted by the Board in the last GRA be approved as no valid alternative allocation has been proposed (Exhibit 189).

The City concluded that there is no new evidence before the Board that would change the classification of costs to energy and demand (Exhibit 186).

The Board accepts the allocation that has been proposed (YUB - YEC/YECL - 1 - 51). It was affirmed as Board Recommendation #2 in the Cost of Service Study Report and the Board agrees that there is no new evidence to change that opinion. However, the Board considers this issue open and subject to review in a future proceeding.

4.0 RUN-OUT RATES

It is New Era Electric Corporation's ("New Era") contention that run-out rates are important to provide the correct price signal to consumers so that conservation and energy alternatives can be properly evaluated. In fact, the run-out rates should properly incorporate long-run marginal costs.

New Era indicated that this currently is not possible since the Companies have not provided this information and are in violation of a Board Order (Cost of Service Study Report, page 40, Recommendation #11) which required a long-run marginal cost study to be performed on the system. This report stated that:

“for the purpose of identifying long-run marginal costs that should appropriately be included in run-out rates, and the results of this study should be presented to the Board by the Companies at the time of the next general rate application.”

New Era's review of the Good Hope Lake contract and the 1966 cost of service indicated that the operating and maintenance cost of \$.016/kW.h is incorrect and that the proper rate should be in the range of \$.064 to \$.10/kW.h. Based on this information, New Era concluded that the Companies achieved a before-tax return on equity of between \$67,000 and \$134,000.

Since this information is vital to rate design and the Companies were unwilling to complete the assignment as the Board Order required, the intervenor requested that the Board appoint an independent consultant to develop the recommended study (Exhibit 176).

The Companies state that there is a distinction between “Recommendations” as set out in the 1992 Cost of Service Report and Board Orders as a result of a General Rate Application hearing. In any case the Board reviewed this “Recommendation” in the 1993/94 GRA (Section 5.2). The Companies provided the required information in the Capital Hearing submission (Table 1, page 2.3). The Board reviewed this analysis in the capital hearing and did not agree with New Era that the long-run diesel costs were unreasonable.

With regard to the diesel installation at Good Hope Lake, the Companies point out that it is outside the jurisdiction of the Board. It is a negotiated contract that therefore bears little resemblance to regulated diesel operation and, therefore it provides no basis for comparison with regulated communities in the Yukon.

The Companies submit that the run-out rates have been prepared on a basis that is consistent with OIC 1995/90 and which the Board approved in the 1993/94 GRA. This method was consistent with accepted rate design principles and reflects the incremental costs. The Companies assert that it is only New Era that demands a change in the rate to reflect long-run as opposed to short-run marginal costs (Exhibit 189).

The Board finds that the run-out rates have been designed consistent with rate design principles and specific directions established in OIC 1995/90. The resultant rate in each of the five zones (Hydro-Diesel, Watson System, Dawson System, Small Diesel and Old Crow) reflect short-run variable costs (Exhibit 1, Tables 3.2 and 3.3) which the Companies must meet.

Under item 10 of the Settlement, the Companies are committed to provide a cost assessment of each of the communities in the four rate zones (based on the 1992 methodology revised with current information). The Board is cognizant that rate design objectives may be in conflict and there must be trade-offs to achieve a particular outcome. In this case, revenue stability, recovery of cost and the appropriate price signal are achievable results in the current methodology that have been incorporated in the run-out rates. The Board agrees that it is necessary to provide the correct price signals to consumers which accurately reflects costs of providing service so that rational energy choices can be made. The Board believes that the study to be filed by the Companies on July 1, 1996 is an important element of future rate design and conservation programs. This material has been requested by intervenors previously and the Board hopes that distribution and consideration of this costing data will assist in building an ongoing productive consensus between the interests of customers and the Companies.

5.0 REVENUE/COST RATIOS

Subject to rates that are maintained to fund the Rate Stabilization Fund, the Application proposed rate adjustments for non-industrial customers that will bring revenues closer to costs for specific classes (Table 3.1). As previously noted, OIC 1995/90 requires that rates to the industrial class be sufficient to cover its cost of service. Arguments on the appropriate revenue/cost ratios to be achieved in the residential class were submitted by

the Utilities Consumers' Group and the Association of Yukon Communities, with reply by the Companies.

The Utilities Consumers' Group requests that the Board direct the Companies to not increase the revenue/cost ratio for the residential class above 75% for the test years or for the foreseeable future (Exhibit 180).

The Association of Yukon Communities requests that the revenue/cost ratio for the residential class remain at its present 78-80% range for the foreseeable future.

In the 1992 Review of Cost of Service and Rate Design, Recommendation #9, the Board recommended:

“that a target range for revenue to cost ratios of 90% to 110% be established for all customer classes other than the industrial class, and that the Companies take the necessary steps to improve the quality of their cost of service studies so that a target revenue to cost ratio of 95% to 105% will be attainable.”

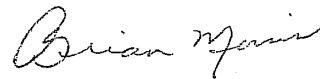
In 1996 the revenue/cost ratio for the non-governmental class was approximately 79% but after rate relief this declines to 68%. The Application does not propose any change in the non-government residential rate until the government rate relief has been eliminated since, until then, residential customers will see no changes in their bills and the correct price signal won't occur. However, the Board-approved reduction in revenue requirement will result in the residential revenue/cost ratio moving to 80% in 1997.

In the Board's view, this rate design provides a legitimate but modest signal that rates are moving in the correct relative direction to meet the respective costs of each class. The Companies are directed to file for approval tariff schedules together with supporting evidence that demonstrate compliance with the Board's Decision.

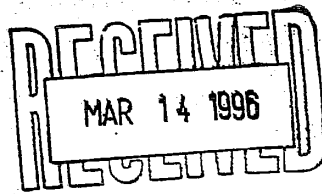
The Companies are to design a rate shift program that would target revenue/cost ratios in the range of 90% to 110% over a ten year period (T. 53). These proposals may include setting up a Rate Redistribution Fund which would hold a portion of the total rate relief in a particular year so that it can be used in subsequent years to mitigate a rate increase to a specific class.

DATED at the City of Whitehorse, in the Yukon Territory, this 11th day of June, 1996.

BY ORDER



Brian Morris
Chair



March 14, 1996

Mr. J. Slater
Secretary
Yukon Utilities Board
P.O. Box 2703
Whitehorse, Yukon
Y1A 2C6

FEED FAX THIS END	
FAX Sent via FAX	
To:	MR. J. SLATER
Dept.:	YUKON UTILITIES BOARD
Fax No.:	8,1403 667-5055
No. of Pages:	14
From:	MR. W. J. G. PANT
Date:	MARCH 14, 1996
Company:	
Fax No.:	
Comments:	
Post-it	fax pdc 7803E

Dear Mr. Slater:

Re: Settlement of Certain Issues Concerning
Revenue Requirement and Rate Application of YEC and YECL ("the Companies")

As a result of the public workshops and settlement discussions held during the week of March 4, 1996 a proposed settlement has been achieved with respect to numerous issues in the Companies' Application. The proposed settlement and the letters of endorsement from participants are attached for the use of the Board Panel hearing this Application. This information is to be made public and available for review by any participants in the process.

You will note that the Utilities Consumers Group ("UCG") letter of endorsement for most of the settlement package includes a number of adjustments. UCG no longer supports the negotiated level of return on equity ("ROE") at 11.25% for YECL (YEC is to receive an ROE one-half percent lower). UCG proposes to file the Decision of the Nova Scotia Utility and Review Board which apparently has set a return on equity for Nova Scotia Power at 10.75%.

In preparation for review of ROE, all parties may wish to analyse the package of information made available as a result of the public workshops. The proposed ROE of 11.25% is equal to that allowed by the National Energy Board for low risk utilities based on a forecast of long Canada interest rates at 8%. The proposed settlement return is 25 basis points higher than that awarded the lowest risk utility in British Columbia by the B.C. Utilities Commission, based on a long Canada forecast of 8%. Other data provided, indicates that returns to other utilities are higher than that level in other jurisdictions and the new information from UCG identifies one tribunal which has awarded a lower return on equity. Parties may wish to review the circumstances of the award in Nova Scotia in comparison with that provided by other tribunals in Canada, the evidence of McShane and Sherwin and the extent to which the benchmark long Canada bond has recently increased up to 8.22%.

UCG also proposes that the net revenues of the Companies effectively become "decoupled". This issue has not previously been raised in this process. In such an instance any excess earnings or deficiencies will be offset so that the company earns its allowed return on equity in both good years and bad. It will be up to the Board to determine if this new issue should be considered in this hearing, studied towards review at a later period, or dismissed.

We believe that concerns with respect to items 2, 9 and 6 of the proposed settlement are covered by the settlement terms.

By way of procedures on the first day of the hearing, we expect that the Companies would provide a panel to explain the terms of the settlement. Other signatories to the settlement would speak to their endorsement of the package. UCG and other non-signatories would undertake any cross-examination of ROE or issues not supported. Thereafter, UCG or others may lead evidence in support of their positions. Following final argument, the Board may wish to retire to consider whether it is prepared to accept the settlement. If any segments of the settlement are to be altered the Board should provide an opportunity for parties to open up other issues which they may have previously tied together in their acceptance of the settlement.

Yours truly,



W.J. Grant

WJG/mmc

C O N F I D E N T I A L

VIA FACSIMILE

March 11, 1996

Dear :

Re: Proposed Settlement of Issues
Concerning the Revenue Requirement
and Rate Design Application of YEC and YECL

The purpose of this letter is to record the settlements we have achieved with respect to specific issues in the YEC and YECL ("the Companies") Application. This letter remains confidential until it is submitted to the Yukon Utilities Board for consideration. I, therefore, ask that you provide to me a communication of endorsement for the proposal so that we may forward it to the Board and make it public by Wednesday, March 13, 1996.

I have taken the liberty of reordering issues in our proposed settlement working sheets so that they align better with the subject areas of discussion in the Application. I have also added words to the bullets that we have agreed upon to explain the settlement to those parties who were not present at negotiations.

The settlement participants agree with the content and details of the Application, save for the following adjustments and identification of specific issues to be reviewed by the Board in public hearing. It is recognized by all the parties that the agreement represents a package proposal within which there has been give and take by all parties. No issue is to be severed from the proposed settlement without allowing signatories the opportunity to address other related issues in the package.

The terms of the settlement are as follows:

1. Return on Equity ("ROE")

It is agreed that the ROE for 1996 and 1997 is to be set at 11.25 percent and that a Diesel Contingency Fund is to be established.

2. Diesel Contingency Fund

This fund is to replace the proposed rate stabilization fund. The fund will operate to smooth customer rate changes and offset forecast diesel costs. Rates and the fund will be determined using the long-term average water expected to be available for generation (105 + 246 GW.h). The initial funding will be determined based upon the funds available as at December 31, 1995. If additional funding becomes available due to other determinations with respect to diesel costs or other utility costs in 1995, the fund will be adjusted. The fund is only to be used for the purposes of stabilizing customer rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates.

The cap on the fund is set at the initial contribution level. If the fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider to customers over the following two years. If the fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and

negative cap levels. The fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.

The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund. The annual report to the Board will also include a forecast of available water for the following year.

3. Capital Structure

The Companies agreed to back preferred shares out of their capital structure as soon as feasible. As the preferred shares are refunded, the Board is to consider appropriate common equity levels at future GRA hearings, having regard to the most efficient capital structure for the future.

4. Demand-Side Management ("DSM")

The DSM costs identified in the Application are accepted. A working group is to be formed, under terms of reference set by the Board, to make recommendations on energy management, conservation and efficient use programs and rates. The working group will also consider rate methods to encourage industrial self-generation when this will benefit system rates. The working group will also consider joint programs with municipalities. This working group is to be convened within one month following the Decision and a report is to be filed with the Board no later than November 1, 1996.

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The proposed capital projects schedule of the Companies is agreed to with the following changes:

- The new diesel plant at Dawson is agreed to.
- The Grum Substation is to be reassessed with ARM and it will only be added if required, and if alternative generation is not feasible. The capital cost of the substation and additional works is to be recovered from ARM so that there will be no impact on other customers.
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- The proposed automatic meter reading program is removed from the 1997 budget and will be reconsidered for inclusion in 1998, or later.

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The revenue requirement budgets are accepted with the following conditions or changes:

- The sales forecast is to be revised based on the ARM Slurry Pipeline not proceeding.
- The Companies will revise the budgets to reflect the agreed upon long-term average water levels in the Diesel Contingency Fund.
- The Companies are undertaking a revised line loss study which is to be filed before the hearing and will be considered at the hearing.

- The program of additional maintenance for upgradings which is scheduled for completion in 1996 has been reviewed and is agreed to by the parties.
- The escalating charges from YECL's parent company, including potential future customer information system charges, are to be reviewed annually and the company is to seek out least cost alternatives.
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The parties agree that the 1995 Interim Rates should be confirmed as permanent.

9. ARM Interim Rates

The interim rates outstanding for ARM since 1994 are to be confirmed as permanent.

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YECL and YEC are to commit to provide a preliminary cost assessment of each community in the four zones based upon the same methodology as was used in the 1992 study, updated to use 1995 data. The cost assessment is to be filed with the Board by July 1, 1996.

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It is agreed that these reports should be replaced by performance indicators as they are developed. Until then quarterly reporting should be adequate for Board and customer reviews.

The companies are to provide an updated filing to the Board showing the revised revenue requirements of this proposed settlement. It may be that the reductions identified will lead to lower rates in 1996. That filing is to be made by Friday, March 15, 1996.

On another matter, the participants considered the UCG complaint with respect to water spillage in 1993 and 1994. The parties were unable to achieve a consensus view to suggest a resolution of the complaint. All intervenors present have agreed that this complaint should be heard at the upcoming public hearing.

In closing, I wish to commend the efforts of the Companies and all intervenors at the workshops and settlement discussions. The extensive efforts made by all parties to understand each issue along with the concerns and interests of other parties has allowed this settlement to come to fruition.

Yours truly,

W.J. Grant

WJG/ssc

YUKON
ENERGY



Our File: 2/8025

YUKON ENERGY
CORPORATION
#304-204 LAMBERT S
WHITEHORSE
YUKON Y1A1Z4
Telephone (403) 667-5011
FAX (403) 668-3327

March 12, 1996

British Columbia Utilities Commission
P.O. Box 250
900 Howe Street, Sixth Floor
Vancouver, B.C.
V6Z 2N3

Attention: Mr. W. J. Grant, Esq

Dear Sir:

Re: Proposed Settlement of Issues Concerning the Revenue Requirement and Rate
Design Application of YEC and YECL

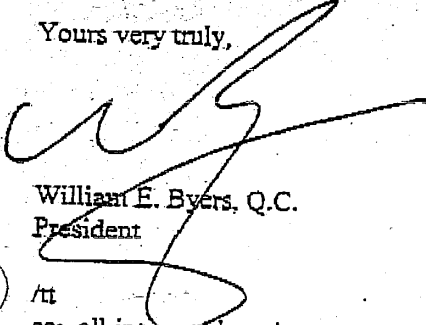
The Yukon Energy Corporation fully endorses and accepts the Settlement of Issues as contained in your letter dated March 11, 1996 and received by the Corporation via FAX on March 12, 1996.

There is one caveat to be noted in regard to paragraph number one, Return on Equity ("ROE"): the ROE set at 11.25 percent is the ROE of YECL; by statute the ROE of YEC is thereby set at 10.75 percent for 1996 and 1997.

The writer also wishes to thank all who participated in the workshops and settlement discussions as I believe this bodes well for not only the current GRA but for future applications as well. I believe that we have taken a large step towards reducing the costs of such applications to the rate payers of the Yukon.

I especially wish to commend Messrs. Grant and McKinley for their patience, expertise and commitment to assisting all of the parties to work through and with this new process.

Yours very truly,


William E. Byers, Q.C.
President

/s/

cc: all interested parties

C:\DATA\BILLING\1-17\BUC\7/12/96



City of Whitehorse

2121 SECOND AVENUE • WHITEHORSE, YUKON Y1A 1C2 • TELEPHONE: (403) 667-6401
FAX: (403) 668-8384 City Hall • (403) 668-8387 Purchasing • (403) 668-8386 Municipal Services
FAX: (403) 668-8388 Transit • (403) 668-8389 Firehall #1



March 12, 1996

File #: 3440-0203

W. J. Grant
British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, B.C.
V6Z 2N3

Dear Sir:

RE: Proposed Settlement of Issues Concerning the Revenue
Requirement and Rate Design Application of YEC and YECL

The City of Whitehorse has reviewed the letter (dated March 11, 1996) recording the settlements achieved with regard to YEC/YECL's Revenue Requirement and Rate Design Application for 1996 and 1997. The City endorses the record as presented in this letter as the settlement achieved at the workshop and negotiation sessions of March 4 to 7, 1996 with the clarification noted below.

The City believes the Diesel Contingency Fund agreement was achieved on the basis that a review of the operation of this fund occur at the next GRA to try and make improvements based on experience. The wording of this section (2) is not clear as to this review occurring and the words may need to be added.

The City wishes to thank all participants in the workshops and settlement discussions believing that the format used provided for a very positive consensus building and is an excellent method for future rate applications. The City would like to thank B.C. Utilities Commission staff for their hard work and commitment to the process.

Yours truly,

Douglas D. Raines
Director of Municipal Services

ddr/dls

: All Interested Parties

R.C.M.P. CENTENNIAL "WORKING WITH YUKON PEOPLE"



THE YUKON ELECTRICAL COMPANY LIMITED

An **ATCO** Company

P.O. BOX 4190, WHITEHORSE, YUKON Y1A 3T4 • TELEPHONE (416) 632-7000 • FAX (416) 663-3066

March 12, 1996

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Mr. W. J. Grant

Dear Sir:

Re: YEC/YECL GRA Proposed Settlement

The Yukon Electrical Company Limited (YECL) has reviewed the "Proposed Settlement of Issues Concerning the Revenue Requirement and Rate Design Application of YEC and YECL" dated March 11, 1996 and find it to be an accurate record of the agreement reached between the interested parties on March 6 and 7, 1996.

YECL therefore endorses the proposal as contained in the above-referenced document.

Yours truly,

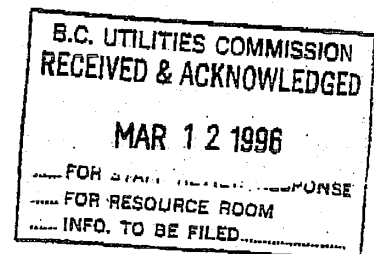
THE YUKON ELECTRICAL COMPANY LIMITED

C.H. Kerslake, P.Eng.
Vice President and General Manager

CHK:ds

encl:1/revoyt

Post-It® Fax Note	7671	Date	MAR 12/96	# of pages	1
To	MR. W. J. GRANT	From	H. KERSLAKE		
Co./Dept.	BCUC	Co.	YECL		
Phone #		Phone #			
Fax #	604-660-1102	Fax #	403-668-3965		





117 Industrial Road, Whitehorse, Yukon Y1A 2T8
Telephone (403)633-5588 Facsimile (403)668-6518

March 12, 1996

British Columbia Utilities Commission
P.O. Box 250
900 Howe Street, Sixth Floor
Vancouver, B.C.

Via Facsimile No: (604) 660-1102

Attention: Mr. W. J. Grant, Esq

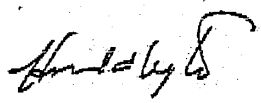
Dear Sir

Re: Proposed Settlement of Issues Concerning the Revenue Requirement & Rate
Design Application of YEC and YECL

Anvil Range Mining Corporation endorses and accepts the Settlement of Issues contained in your letter dated 11 March, 1996 and received 12 March, 1996 via facsimile.

Anvil wishes to thank all who participated in the workshops and settlement discussions of the 4 to 7 March, 1996. Also, Anvil thanks the B.C. Utilities Commission staff for their work in bringing the workshops and settlement discussions to a fruitful conclusion.

Best regards


Kurt A. Forgaard
President & Chief Executive Officer

/bd YEC\hrcawig

Utilities Consumers' Group

Box 6086, Whitehorse, Yukon Y1A 5L7
Fax (403) 633-6361

March 12, 1996

British Columbia Utilities Commission
P.O. Box 250
900 Howe Street, Sixth Floor
Vancouver, B.C. V6Z 2N3

SENT BY FAX: (604) 660-1102

Attention: W.J. Grant, Esq.

Dear Mr. Grant:

Re: Proposed Settlement of Issues
Concerning the Revenue Requirement
and Rate Design Application of YEC and YECL

The Utilities Consumers' Group has received your letter dated March 11, 1996 regarding the above.

In the time since last week's NS Workshop, we have had the opportunity to reflect on the process, to absorb the significant amount of information exchanged during the 4 days and to consider the developments in a broader perspective. We have concluded that you, Mr. McKinlay, and the two other BCUC staff members deserve recognition and praise for the constructiveness displayed by all participants during the 4 days of meetings.

These observations have enabled us to arrive at additional conclusions which follow.

BCUC's Negotiated Settlement Process - Policy, Procedures and Guidelines - January 1996, the model for the negotiated settlement process used with the YEC/YECL 1996/97 GRA, says: *"When participants sign off a proposed settlement they agree to provide their support to the agreement and agree to waive their right to present evidence and cross-examine on matters dealt with by the agreement."*

Part 9 of the booklet says: *"There are, however, circumstances where the agreement may require amendment: (i) One or more participants may become aware of new information that was not reasonably available to them at the time of the settlement discussions and which has a significant bearing on the assumptions upon which the settlement was reached".*

UCG is aware of new information: Nova Scotia Power was recently awarded a return on equity of 10.75% by the Nova Scotia Utility and Review Board (NSU&RB). The companies listed Nova Scotia Power (NSP) as a comparable in response to UCG-1-56, in APL's ROE testimony and at the ROE presentation on March 4, 1996. In those instances, NSP's ROE was pegged between 11.50% - 12.00%, or .75% - 1.25% higher than currently allowed.

This new information appears to undermine results from the comparable earnings test used by the companies' experts: *"Dr. Sherwin and Ms. McShane concluded that a fair return for a typical high grade utility is in the range of 11.8% to 12.6% (midpoint 12.2%)."*

As noted in your letter, the agreement represents a package proposal within which there has been give and take by all parties. In our view, the 11.25% ROE accepted by the companies represented what we thought was a "give" on their part in exchange for the several "takes" in the remainder of the package. However, the new information sheds new light on that perspective. We no longer believe that the companies gave to the extent previously thought and the package is unfair until a reasonable concession is made.

It is our position that YECL's ROE should reflect the findings of the NSU&RB at 10.75%. Consequently, UCG must dissent on section (1) of the package. Confirmation of the NSU&RB decision is pending and we will forward the information once it is available.

At this opportunity we forward another proposal with respect to item #1: *"The companies' ROE earnings should be capped at the YUB approved level and excess earnings should be transferred to the Diesel Contingency Fund (DCF)"*. Protecting the interests of customers and YEC's shareholders (the Yukon public) by allowing those customers and citizens to benefit from savings should be incentive enough for the companies to reduce costs. Moreover, the companies should not over-earn at the expense of consumers.

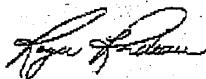
In addition, UCG proposes the following three amendments to the package:

- Part (2), DCF, the last sentence should be changed to: *"The companies shall submit to the Board a report called Diesel Contingency Fund Forecast and Variance Report by March 31 each year that shall include a forecast of inflows and generation by plant for the coming calendar year and a variance analysis of the previous calendar year complete with an explanation for any variance."*
- Part (9), ARM Interim Rates, should be retroactive to Jan. 1, 1996.
- Part (6), Revenue Requirement, should not be set until all adjustments have been taken into account and the Board has approved the final amount.

We hope that all parties will understand our position and support these proposed amendments prior to the hearing in order to reduce hearing time and costs. Although UCG cannot agree to the package in its present form, we are optimistic that the problems can be overcome in time for the settlement package to proceed with the endorsement of all parties.

If you have any comments or questions, please contact us at your convenience.

Yours truly,



Roger Rondeau
President

xc: Your mailing list



TOWN OF WATSON LAKE

P.O. Box 590, Watson Lake, Yukon Y0A 1C0 403-536-7778 Fax: 403-536-7522

March 13, 1996

Mr. W. Grant
British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, B.C.
V6Z 2N3

Dear Sir:

Re: Proposed Settlement of Issues concerning the Revenue Requirement and Rate Design Application of Y.E.C. and Y.E.C.L.

I have reviewed your letter of March 11th and on behalf of the member communities of the Association of Yukon Communities agree with the settlement as proposed. We agree with the City of Whitehorse that the operation of the Diesel Contingency Fund should be reviewed at each G.R.A. in order to provide an improvement process.

We will address the issue of cost of service allocation at the upcoming public hearings.

The Association of Yukon Communities is pleased that all parties have committed to this process of consensus settlement. We feel this is a much more cost effective method of achieving a settlement and of benefit to all Yukoners. We wish to thank you and your staff for your dedication and commitment in assisting the Companies and intervenors in reaching this settlement.

Your truly,

J.B. Ravenhill
Chairman, Energy Committee
Association of Yukon Communities

JBR/tc

HOME OF THE WORLD FAMOUS SIGNPOST FOREST



NEW ERA Electric Corporation

Northern Small Hydro Specialists

Box 4491, Whitehorse, Yukon, Canada Y1A 2R8 Phone/Fax 403-668-3978

March 13, 1996

TO: Jim Slater
Yukon Utilities Board

BY: Fax 667-5059 PAGES TO FOLLOW: 0

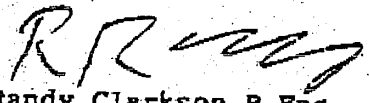
Dear Mr Slater:

RE: Proposed Settlement of Issues Concerning the Revenue Requirement and Rate Desing Application of YEC and YECL.

RE: Cost of Service Issues

NEW ERA Electric Corporation has reviewed the "Proposed Settlement of Issues Concerning the Revenue Requirement and Rate Desing Application of YEC and YECL" and is prepared to accept the proposal.

However NEW ERA is DOES NOT believe that Cost of Services Issues can be appropriately resolved with written submission and argument. We strongly believe that proposed run-out rates are heavily cross subsidized, do not reflect true costs, and will lead to a faulty allocation of resources. We feel that it is imperative that we are able to address the issue of Cost of Service at the hearing. The minor cost savings achieved through avoiding this subject at the hearing are miniscule as compared to the present and future costs of these faulty allocations.


Randy Clarkson P.Eng.

Peter Percival P.Eng.

cc

H Kerslake, Yukon Electrical Corporation 668-3965

W Byers, Yukon Energy Corporation 668-3327

K Forgaard, Anvil Range Mining Corp 668-6518

L Bagnell, Association of Yukon Comm 668-7574

D Raines, City of Whitehorse 668-8364

R Rondeau, Utilities Consumer Group 633-6361

VIA FACSIMILE
03,668-3327

March 11, 1996

Mr. Bill Byers
Yukon Energy Corporation
304 - 204 Lambert Street
Whitehorse, Yukon Y1A 1Z4

EXHIBIT B-16

Dear Mr. Byers:

Re: Proposed Settlement of Issues
Concerning the Revenue Requirement
and Rate Design Application of YEC and YECL

The purpose of this letter is to record the settlements we have achieved with respect to specific issues in the YEC and YECL ("the Companies") Application. This letter remains confidential until it is submitted to the Yukon Utilities Board for consideration. I, therefore, ask that you provide to me a communication of endorsement for the proposal so that we may forward it to the Board and make it public by Wednesday, March 13, 1996.

I have taken the liberty of reordering issues in our proposed settlement working sheets so that they align better with the subject areas of discussion in the Application. I have also added words to the bullets that we have agreed upon to explain the settlement to those parties who were not present at negotiations.

The settlement participants agree with the content and details of the Application, save for the following adjustments and identification of specific issues to be reviewed by the Board in public hearing. It is recognized by all the parties that the agreement represents a package proposal within which there has been give and take by all parties. No issue is to be severed from the proposed settlement without allowing signatories the opportunity to address other related issues in the package.

The terms of the settlement are as follows:

1. Return on Equity ("ROE")

It is agreed that the ROE for 1996 and 1997 is to be set at 11.25 percent and that a Diesel Contingency Fund is to be established.

2. Diesel Contingency Fund

This fund is to replace the proposed rate stabilization fund. The fund will operate to smooth customer rate changes and offset forecast diesel costs. Rates and the fund will be determined using the long-term average water expected to be available for generation (105 + 246 GW.h). The initial funding will be determined based upon the funds available as at December 31, 1995. If additional funding becomes available due to other determinations with respect to diesel costs or other utility costs in 1995, the fund will be adjusted. The fund is only to be used for the purposes of stabilizing customer rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates.

The cap on the fund is set at the initial contribution level. If the fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider to customers over the following two years. If the fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and

negative cap levels. The fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.

The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund. The annual report to the Board will also include a forecast of available water for the following year.

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The Companies agreed to back preferred shares out of their capital structure as soon as feasible. As the preferred shares are refunded, the Board is to consider appropriate common equity levels at future GRA hearings, having regard to the most efficient capital structure for the future.

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- The program of additional maintenance for upgradings which is scheduled for completion in 1996 has been reviewed and is agreed to by the parties.
- The escalating charges from YECL's parent company, including potential future customer information system charges, are to be reviewed annually and the company is to seek out least cost alternatives.
- The Companies are to provide actual rate application costs for determination of final rates.

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4

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The companies are to provide an updated filing to the Board showing the revised revenue requirements of this proposed settlement. It may be that the reductions identified will lead to lower rates in 1996. That filing is to be made by Friday, March 15, 1996.

On another matter, the participants considered the UCG complaint with respect to water spillage in 1993 and 1994. The parties were unable to achieve a consensus view to suggest a resolution of the complaint. All intervenors present have agreed that this complaint should be heard at the upcoming public hearing.

In closing, I wish to commend the efforts of the Companies and all intervenors at the workshops and settlement discussions. The extensive efforts made by all parties to understand each issue along with the concerns and interests of other parties has allowed this settlement to come to fruition.

Yours truly,



W.J. Grant

WJG/ssc

MiscCor/YEC•YECL Specific Issues



Our File: 2/5590-08-00
2/8005-07

JUN 11 1999

YUKON ENERGY
CORPORATION
P.O. BOX 5920
WHITEHORSE
YUKON Y1A 5L7
Telephone (867)667-5028
FAX (867)393-6327

EXHIBIT B18

June 2, 1999

Yukon Utilities Board
#19, 10014 1st Avenue
P.O. Box 6070
Whitehorse, Yukon
Y1A 5L7

FAXED
99/06/04
Em

Attention: Mr. Jim Slater, Board Secretary

Dear Sir:

Re: Diesel Contingency Fund Filings: 1996 to 1998

Please find attached the final report, which details the changes to the Diesel Contingency Fund (DCF) in 1998. Also attached are revised reports for 1996 and 1997. This filing includes a correction to remove fire-related impacts for the period October through December 1997. It also includes, for convenience, copies of relevant DCF tables for The Yukon Electrical Company Limited. We understand that both utilities have agreed on all of the DCF filings for 1996 through 1998.

The 1996/97 Settlement Agreement provided as follows:

"The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund. The annual report to the Board will also include a forecast of available water for the following year."

Please find attached the following schedules and tables related to the Diesel Contingency Fund.

1. Summary of 1996 and 1997 DCF calculation revisions
2. DCF continuity schedule: January 1, 1996 - December 31, 1998
3. Revised 1996 and 1997 as well as final 1998 DCF schedules.

The Yukon Utilities Board is requested to approve the 1998 DCF as filed. Also, the Board has not yet approved the DCF filings for 1996 and 1997. It is requested that the Board approve the revised DCF schedules for 1996 and 1997 as final.

As requested by BCUC staff, The Yukon Electrical Company Limited and Yukon Energy Corporation discussed the DCF with BCUC staff on April 13, 1999. The current filing includes background information to explain the operation of the DCF to date (see below). Yukon

June 2, 1999
Yukon Utilities Board
Attention: Mr. Jim Slater, Board Secretary
Page 2

Electrical and Yukon Energy will prepare a submission to the Yukon Utilities Board regarding the operation of the DCF for 1999 and beyond.

We note that the Settlement requires that the annual DCF report include a forecast of available water for 1999. YEC will file with the Board, as soon as possible, the annual forecast in this regard for its facilities when this forecast is filed with the Yukon Territorial Water Board.

GENERAL INFORMATION ON DCF OPERATIONS

The DCF was established as at January 1, 1996 in accordance with the 1996/97 Settlement Agreement. Except for material differences specified in the 1996/97 Settlement Agreement, the DCF has been operated on the same basis as the Low Water Reserve Fund (LWRF) previously in place from 1991 through 1995.

Operation of the DCF has been described previously in letters to the Board dated May 6, 1997 and June 24, 1997. For convenience, the following points are summarized:

- (a) **The opening balance of the DCF as at January 1, 1996:** The DCF opening balance was \$4,040,046 as detailed in response to Question 2 in the June 24, 1997 letter (this earlier letter incorrectly references the date January 1, 1997 rather than January 1, 1996).
- (b) **The positive and negative caps on the DCF:** As confirmed in the response to Questions 3 and 4 of the June 24, 1997 letter, the current "cap" on the DCF pursuant to the 1996/97 Settlement Agreement equals the initial contribution (namely, \$4,040,046). Further, the current "negative cap" on the DCF pursuant to the 1996/97 Settlement Agreement is -\$4,040,046, i.e., the same amount (with the reverse sign) as specified for the initial contribution and the current "cap" for contributions to the DCF. It is understood that all of the DCF terms and conditions are to be reviewed at the next GRA.
- (c) **Long-term average non-diesel generation:** The DCF has operated to offset diesel generation cost changes for the WAF system that are caused solely by variances from long-term average levels of WAF system hydro and wind generation. The Negotiated Settlement Package (NSP) stipulates long-term average hydro generation of 105 GW.h (for YEC's Aishihik facility) plus 246 GW.h (for YEC's Whitehorse Rapids facility). The much smaller YEC wind generation (0.3 GW.h) and YECL Fish Lake hydro (10 GW.h), which were not included in the earlier LWRF, have also been included in the DCF operation in accordance with the 1996/97 General Rate Application. It is understood in this regard that the NSP effectively adopted the 1996/97 General Rate Application unless specific mention was made of an issue in the NSP or the Board made a specific direction to alter the NSP.
- (d) **Diesel generation saving or excess for YEC:** The calculation of diesel generation saving (or excess) related to non-diesel generation for YEC is calculated to remove the effects of variances in total WAF generation for YEC (expected generation at line 14 for YEC). This reflects procedures previously approved for LWRF operation, based on Decision 1992-1 and the 1993/94 GRA response to WHSE-YEC/YECL-33(a). When the

June 2, 1999
Yukon Utilities Board
Attention: Mr. Jim Slater, Board Secretary
Page 3

LWRF was last calculated with diesel on the margin (1992), it was calculated on the basis of annual numbers without attempting to assess minimum diesel requirements (at line 10 in the YEC DCF) on either a monthly or annual basis.

- (e) **Diesel cost savings or excess for YEC:** The YEC diesel cost savings or excess are calculated based on the approved forecasts for 1996 for YEC WAF diesel generation per kW.h costs, assuming standard efficiency at 3.71 kWh/litre of fuel and YEC average WAF diesel fuel price forecast at approximately 29.60 cents per litre. Variable O&M costs per kW.h for diesel generation are assumed at 1.6 cents per litre, as assumed for the approved 1996/97 GRA retail run-out rate calculations for WAF. These procedures in general reflect the procedures previously approved for operation of the LWRF.
- (f) **DCF calculations for YECL Fish Lake:** Imputed diesel generation savings or excess related to the YECL Fish Lake hydro facility are calculated as follows:
 - actual Fish Lake generation is compared with the long-term average Fish Lake generation forecast per the 1996/97 GRA filing
 - imputed diesel cost savings or excess for YECL are calculated assuming the YEC WAF diesel generation standard efficiency and fuel prices are described above.
- (g) **Interest calculations:** The NSP provided for interest income or expense to be calculated for the DCF based on stipulated provisions. No similar provisions existed for the LWRF.
- (h) **DCF suspended when diesel is not on the margin:** The evidence provided to the Board in the NSP, and during the 1996 GRA hearing, specified that the DCF was to be only used for offsetting diesel generation, and that the DCF would only be active when diesel is on the margin. In this regard, the 1996 evidence presumed that diesel generation is not on the margin for the WAF system when the Faro mine is closed; this presumption assumed the availability of normal long-term hydro generation capability.

ADJUSTMENTS TO 1996 AND 1997 DCF FILINGS

The 1996 and 1997 DCF filings as previously provided to the Board generally reflected principles and practices as described above.

The latest filing with the Board, however, includes various adjustments to the YEC-related numbers as documented in the attached table titled "Summary of 1996 and 1997 DCF Revisions". These adjustments, in summary, increase the DCF December 31, 1997 balance as previously reported by \$436,923.26. The major changes are commented on briefly below:

- **Interest calculations:** Adoption of standard monthly interest income calculation procedures, starting January 1, 1996. This includes adjustment of entries as required for the initial opening balance, and other subsequent payments, to reflect the proper timing for these transactions.

June 2, 1999
Yukon Utilities Board
Attention: Mr. Jim Slater, Board Secretary
Page 4

- **Line 10 correction – determination as to whether diesel is on the margin:** Correction was made to remove any “minimum required diesel generation” assumption for YEC at line 10 of the DCF table. This line is now used solely to specify whether diesel generation is on the margin for YEC in each month (assuming long-term hydro capability). This determination affects both the YEC DCF and the YECL DCF (at line 3). As noted, and as previously reported, diesel was not on the margin from June 1 to October 31, 1997. During 1998, diesel was not on the margin from February 1 to December 31, 1998.
- **Procedures to assess diesel on margin issues when Faro mine closed:** Experience since the Faro mine closure in 1998 has re-affirmed that diesel generation can in fact go back on the margin for the YEC WAF system during certain months, under specific “non-normal” conditions, even though the Faro mine is closed. The line 10 determination regarding “diesel on the margin” is made on the basis of WAF total required generation and normal long-term hydro capability. In order to provide for some minor diesel generation that may occur for voltage stability or peaking purposes, without being related to variances from long-term hydro capability, the DCF is not activated in any month when diesel is not on the margin (per line 10) and YEC diesel generation does not exceed 250,000 kW.h for the month. This adjustment at line 16 of the YEC DCF schedule then allows for the DCF to be activated for actual diesel use during months when the Faro mine is closed and diesel generation is still required in excess of 250,000 kW.h due specifically to below-normal YEC WAF hydro capability. In practice, diesel generation remained less than 250,000 kW.h in all 1997 and 1998 months when diesel was not on the margin (see the line 10 correction above), except for October 1997 and July 1998 – and these exceptions related to YEC fire impacts as described below.
- **Fire-related impacts:** The DCF has been adjusted in 1997 and 1998 to remove impacts caused by fires affecting YEC's operations. Because of the importance of these adjustments, they are explicitly reviewed below in more detail. These adjustments affect three months in 1997 (October to December inclusive).
- **Other minor adjustments:** As noted in the attached material, various other minor adjustments have been made, including corrections to reflect actual YEC generation during the final three months of 1997 and corrections regarding the YUB 1997-7 drawdown amounts.

DCF ADJUSTMENTS TO ADDRESS YEC FIRE-RELATED IMPACTS

Actual diesel generation for YEC was required during three months of 1997 (October through December) due to reduced hydro capability caused by the October 1997 fire at the Whitehorse Rapids hydro facility. These fire impacts have been estimated for each month in the attached tables (see note 5 to the first table). Under the terms of YEC's insurance policy there is a 30-day waiting period during which the cost of any fire-related diesel generation is not claimable. Accordingly, the DCF drawdown for October and November 1997 due to the fire was charged to the YEC Reserve for Injuries and Damages. The DCF drawdown for December 1997 has been charged to the fire insurance claim. (It is noted that YEC's last filing on this fire was last June 1998 in response to UCG-YEC-2-7, which included a letter to the Board dated June 26, 1998. This letter said that costs incurred for extra diesel generation in 1997 have been met in their

June 2, 1999
Yukon Utilities Board
Attention: Mr. Jim Slater, Board Secretary
Page 5

entirely either through use of the DCF, during the non-insured period, or thereafter through insurance coverage. It also noted that the property loss deductible was charged in 1997 through YEC's reserve for injuries and damages – but no mention was made of diesel generation being charged to this account during the non-insurance period. This change from what was previously reported on fire issues is beneficial to the DCF.)

During July 1998, YEC experienced a major forest fire that shut down the Faro transmission line for some time forcing YEC to generate diesel from the Faro plant. This diesel generation impact had nothing to do with hydro generation capability, and thus cannot be charged to the DCF. As noted in the attached table titled "DCF Continuity Schedule 1996-1998", this forest fire impact on the DCF of \$58,182.00 for July 1998 has all been charged to the Reserve for Injuries and Damages.

If you have any questions, please give me a call.

Sincerely,



Rob McWilliam
President & Chief Executive Officer

/dm
Attachments

c John Carroll, General Manager, The Yukon Electrical Company Limited
Cam Osler, InterGroup Consultants Ltd

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Please find attached the following draft schedules and tables related to the Diesel Contingency Fund as filed jointly by Yukon Energy Corporation and The Yukon Electrical Company Limited.

- 1 Summary of 1996 and 1997 DCF calculation revisions
- 2 DCF continuity schedule January 1, 1996 - December 31, 1998
- 3 Revised 1996 and 1997 as well as 1998 DCF calculation schedules

These schedules were prepared by YEC based on YEC's understanding and interpretation of relevant board orders and the intent of the DCF. YECL's understanding and interpretation of relevant board orders and the intent of the DCF may differ from YEC's. These schedules will be reviewed by Barry McKinley of BCUC with YEC and YECL during the week of April 12, 1999.

SUMMARY OF 1996 AND 1997 DCF REVISIONS

	As Filed	Revised	Change	Reference
1996				
Opening balance	500,000.00	4,040,046.00	3,540,046.00	1
Additions (Reductions)	3,540,046.00		(3,540,046.00)	1
YEC Buildup (Drawdown)	(1,034,266.13)	(1,131,866.82)	(97,600.69)	2
YECL Buildup (Drawdown)	(325,803.92)	(325,803.92)	-	
Interest and service charges	148,358.17	188,741.49	40,383.32	3
Closing balance	2,828,334.12	2,771,116.75	(57,217.37)	
1997				
Opening balance	2,828,334.12	2,771,116.75	(57,217.37)	
YUB 1997/7 Drawdown	(348,992.80)	(346,275.62)	2,717.18	4
YEC Fire Impact Buildup	-	516,167.23	516,167.23	5
YEC Buildup (Drawdown)	23,279.99	(13,253.20)	(36,533.19)	6
YECL Buildup (Drawdown)	(177,878.60)	(177,878.50)	-	
Interest and service charges	73,343.31	85,132.72	11,789.41	3
Closing balance	2,398,066.12	2,835,009.38	436,923.26	

- The previously filed schedule, for 1996, showed the YUB approved deposit of \$3,540,046.00 as an addition in March and also included imputed interest calculated retroactively to January 1, 1996. In the revised schedule the \$3,540,046.00 is included as part of the beginning balance of the DCF. Interest on this amount is calculated on a monthly basis from January 1, 1996.
- During 1997, it was noted that the DCF was being incorrectly calculated by manually inputting at Line 10 "minimum required diesel generation" of 635,000 kWh per month for YEC. Line 10 has been adjusted for 1996 and 1997 to deal solely with specifying whether diesel generation is on the margin for YEC each month (assuming long-term average Hydro capability). If diesel remains on the margin throughout the year, the final annual drawdown or build-up is in effect calculated on the basis of annual rather than monthly numbers. In the event that diesel is not on the margin for YEC's WAF generation during any month (assuming long-term Hydro capability), diesel savings (excess) equal zero at Line 16 for YEC (and at line 3 for YECL) in any month when diesel generation is not on the margin for YEC incremental generation. Diesel is not on the margin when so indicated at line 10 for any month (based on long-term Hydro capability), provided that YEC diesel generation does not exceed 250,000 kWh in that month. This procedure allows for some minor diesel generation that may occur for voltage stability or peaking purposes, without being related to variances from long-term Hydro capability. The DCF was specifically approved to deal with diesel generation related solely to variances from long-term Hydro capability.
- The change in interest is a result of calculating interest on the DCF balance on a monthly basis after the DCF schedules were adjusted for the various noted items.
- The YUB 1997/7 Drawdown was incorrectly stated in the original 1997 filing.
- The 1997 DCF calculations have been revised to reflect the reduced Hydro capability resulting from the loss of Hydro generating units in the fire of October, 1997. These revisions are outlined in the following Tables 1, 2 and 3.
- This difference is mainly due to diesel generation for October being in excess of 250,000 kWh when diesel was off the margin (refer to note 2 for the rationale). The difference is also partially due to the fact that the filed 1997 DCF schedule included estimates for generation for the last three months of 1997 as a result of the fire. The revised 1997 DCF schedule has been revised using actual generation figures.

Table 1: DCF - Including Fire Related Diesel Generation:

Line#			OCT-1997	NOV-1997	DEC-1997
Actual generation - Mwh					
1	Hydro	Manual Input	25,580,490	27,651,195	33,706,072
1a	Wind	Manual Input	17,840	6,530	21,370
2	Diesel	Manual Input	357,870	7,140,520	6,747,710
3	Total	Line 1 + Line 2	25,956,200	34,798,245	40,475,152
Forecast Generation - Mwh					
4	Hydro	Manual Input	32,502,676	30,765,226	28,775,136
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,611,765	7,995,231	11,851,208
6	Total	Line 4 + Line 5	36,144,441	38,790,457	41,656,346
Variance - Mwh					
7	Hydro and wind	Line 1 - Line 4	(8,934,346)	(3,137,501)	3,922,304
8	Diesel	Line 2 - Line 5	(3,253,885)	(854,711)	(5,103,488)
9	Total (favourable)	Line 3 - Line 6	(10,188,241)	(3,992,212)	(1,181,184)
Expected diesel generation - Mwh:					
Greater of (savings to a maximum of forecast diesel):					
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
(YEC generation requirement long term avg Hydro capability)					
11	Forecast generation	Line 5	3,611,765	7,995,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,181,184)
13		Line 11 + Line 12	(6,576,476)	4,003,019	10,670,014
14	Expected generation	Line 13 if Ln 10=1 otherwise = 0	-	4,003,019	10,670,014
14a	Maximum savings available	Line 5	3,611,765	7,995,231	11,851,208
15	Actual diesel generation	Line 2	357,870	7,140,520	6,747,710
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 > 250,000)	(357,870)	(3,137,501)	3,922,304
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	(96,461)	(845,688)	1,057,225
19	Standard price(\$ per litre)	Manual Input	0.2889	0.2860	0.2860
Reserve Buildup (drawdown)					
20	YEC Variable O&M cost(\$ per litre)	Manual Input	0.018	0.016	0.016
21	YEC Fuel savings (excess)	Line 18 x Line 19	(28,656.10)	(260,355.87)	312,978.71
22	YEC Variable O&M costs	Line 20 x Line 18	(5,725.92)	(50,200.02)	82,766.88
23	YEC buildup (drawdown)	Line 21 + 22	(34,282.02)	(300,555.89)	375,735.57
24	YECI buildup (drawdown)	See YECI Table	0	(21,445.42)	(13,233.58)
25	Total buildup (drawdown)	Line 23 + 24	(34,282.02)	(322,001.11)	362,501.99

Table 2: DCF - Excluding Fire Related Diesel Generation:

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual Input	25,840,480	31,500,795	34,888,872
1a	Wind	Manual Input	17,840	6,580	21,370
2	Diesel	Manual Input	97,870	3,280,820	5,566,910
3	Total	Line 1 + Line 2	25,956,200	34,798,245	40,475,152
	Forecast Generation - Mwh				
4	Hydro	Manual Input	32,502,876	30,785,228	29,775,138
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,811,765	7,885,231	11,851,208
6	Total	Line 4 + Line 5	36,144,441	38,780,457	41,656,346
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	(6,674,346)	712,089	5,103,104
8	Diesel	Line 2 - Line 5	(3,513,895)	(4,704,311)	(8,284,288)
9	Total (favourable)	Line 3 - Line 6	(10,188,241)	(3,992,212)	(1,181,184)
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	3,811,765	7,885,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,181,184)
13		Line 11 + Line 12	(6,576,476)	4,003,019	10,670,014
14	Expected generation	Line 13 if Ln 10 = 1 other = 0	-	4,003,019	10,670,014
14a	Maximum savings available	Line 5	3,811,765	7,885,231	11,851,208
15	Actual diesel generation	Line 2	97,870	3,280,820	5,566,910
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10 = 1; otherwise = 0, unless Ln 15 > 250,000)	-	712,089	5,103,104
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	-	181,940	1,375,500
19	Standard price(\$ per litre)	Manual Input	0.2960	0.2960	0.2960
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs(\$ per litre)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 16 x Line 19	-	58,821.68	407,200.16
22	YEC Variable O&M costs	Line 20 x Line 16	-	11,393.58	81,649.68
23	YEC buildup (drawdown)	Line 21 + 22	-	68,215.24	488,849.85
24	YEC buildup (drawdown)	See YEC Table	-	(21,445.42)	(13,233.58)
25	Total buildup (drawdown)	Line 23 + 24	-	46,769.82	475,618.27

Table 3: DCF - Fire Impact

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual Input	260,000	3,849,600	1,180,800
1a	Wind	Manual Input	0	0	0
2	Diesel	Manual Input	(260,000)	(3,849,600)	(1,180,800)
3	Total	Line 1 + Line 2	0	0	0
	Forecast Generation - Mwh				
4	Hydro	Manual Input	0	0	0
4a	Wind	Manual Input	0	0	0
5	Diesel	Manual Input	0	0	0
6	Total	Line 4 + Line 5	0	0	0
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	260,000	3,849,600	1,180,800
8	Diesel	Line 2 - Line 5	(260,000)	(3,849,600)	(1,180,800)
9	Total (favourable)	Line 3 - Line 6	0	0	0
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	0	0	0
12	Total variance	Line 8	0	0	0
13	Expected generation	Line 11 + Line 12	0	0	0
14	Expected generation	Line 13 if Ln 10=1 other = 0	0	0	0
14a	Maximum savings available	Line 5	0	0	0
15	Actual diesel generation	Line 2	(260,000)	(3,849,600)	(1,180,800)
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 > 250,000)	357,870	3,849,600	1,180,800
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	98,461	1,037,628	318,275
19	Standard price(\$ per litre)	Manual Input	0.2860		
	Reserve Buildup (drawdown):				
20	YEC Variable O&M costs(\$ per litre)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 18 x Line 19	28,556.10	307,177.33	94,221.48
22	YEC Variable O&M costs	Line 20 x Line 18	5,725.92	61,593.60	18,882.80
23	YEC buildup (drawdown)	Line 21+22	34,282.02	368,770.93	113,114.28
24	YECL buildup (drawdown)	See YECL Table	-	-	-
25	Total buildup (drawdown)	Line 23 + 24	34,282.02	368,770.93	113,114.28

Under the terms of the Insurance policy there is a 30 day waiting period during which the cost of any fire related diesel generation is not claimable. Accordingly the DCF drawdown for October and November was charged to the Reserve for Injuries and Damages. The DCF drawdown for December has been charged to the fire insurance claim.

DCF CONTINUITY SCHEDULE 1996 - 1998

1996	Opening balance (Old LWRF balance)	500,000.00	
	YUB approved deposits	<u>3,540,046.00</u>	4,040,046.00
	YEC withdrawals - Fuel	<u>(942,817.87)</u>	
	YEC withdrawals - O&M	<u>(189,048.95)</u>	(1,131,866.82)
	YECL withdrawals		(325,803.92)
	Interest Income/Service Fees		<u>188,741.49</u>
	Ending Balance		<u><u>2,771,116.75</u></u>
1997	Opening balance		2,771,116.75
	YUB 1997/7 Drawdown		(346,275.62)
	YEC Fire Impact - Charged to the Reserve for Injuries and Damages		403,052.95
	YEC Fire Impact - Charged to the fire insurance claim		113,114.28
	YEC drawdown - Fuel	<u>(11,039.59)</u>	
	YEC drawdown - O&M	<u>(2,213.61)</u>	(13,253.20)
	YECL withdrawals		(177,878.50)
	Interest Income/Service Fees		<u>85,132.72</u>
	Ending Balance		<u><u>2,835,009.38</u></u>
1998	Opening balance		2,835,009.38
	DCF Rider Drawdown		(1,283,018.76)
	Forest Fire Impact - Charged to the Reserve for Injuries and Damages		58,182.00
	YEC buildup - Fuel	<u>399,743.47</u>	
	YEC buildup - O&M	<u>80,154.48</u>	479,897.95
	YECL Net withdrawals		(12,958.18)
	Interest Income/Service Fees		<u>158,646.58</u>
	Ending Balance		<u><u>2,235,758.97</u></u>

[illegible]

TABLE 2: THE YUKON ELECTRIC COMPANY LIMITED - Audited to Dec 31 Continuity schedule, rate ending Dec 31, 1999 - Fixed Continuity Fund Calculations - WAZ System (2005)															
	Line #	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
Adjusted power cost - MWh															
Units	1	Manual input	545,901	645,120	652,050	555,580	851,514	851,815	425,838	454,324	725,543	519,820	455,880	4,781,220	6,648,761
Forecast generation - MWh															
Units	2	Manual input	837,081	850,356	793,803	816,599	798,242	408,296	395,558	976,441	805,816	547,899	818,499	840,944	(1,341,844)
Fixed costs - MWh															
Units	3	Line 1 - Line 2	(291,182)	(204,226)	(109,853)	(264,029)	(145,720)	(185,431)	(406,690)	(421,207)	(141,962)	(377,482)	(254,429)	(292,624)	(3,421,062)
Predefined power purchase cost - MWh															
Units	4	Line 3 if about on target	(251,165,009)	(264,226,000)	(190,853,000)	(264,029,000)	(145,728,000)	(185,431,000)	(406,690,000)	(421,207,000)	(141,962,000)	(377,482,000)	(254,429,000)	(292,624,000)	(3,421,062,000)
Standard efficiency															
Units	5	Line 3 if about on target	0.271	0.271	0.271	0.271	0.271	0.271	0.271	0.271	0.271	0.271	0.271	0.271	0.271
Standard flow	17	Line 17	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)	(73,482)
Standard price per kWh	18	Line 18	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fixed charges (income) - \$000	20	Line 19 + Line 18	(20,220,285)	(24,725,711)	(15,725,108)	(21,098,821)	(11,208,369)	(14,778,210)	(32,699,525)	(33,819,398)	(11,207,298)	(29,198,795)	(29,279,850)	(29,695,361)	(271,249,820)
Variable O&M costs - \$000	21	Line 21 + Line 4	14,918,559	14,967,823	(1,968,485)	(1,254,821)	(2,247,886)	(5,468,401)	(6,728,311)	(6,728,311)	(2,721,280)	(5,247,419)	(5,247,419)	(5,601,381)	(56,412,200)
Revenue building (breakdown) - \$000	22	Line 22 + Line 21	(77,841,825)	(29,143,029)	(16,263,852)	(23,293,642)	(14,956,586)	(17,939,111)	(39,343,000)	(40,547,709)	(13,928,578)	(34,446,214)	(34,526,869)	(35,296,742)	(215,662,020)
Operating reserves	23	Line 23 prior period	(226,000)	(26,217,425)	(52,390,752)	(29,424,509)	(109,817,846)	(114,873,862)	(122,833,811)	(172,678,699)	(212,429,446)	(226,014,731)	(257,441,833)	(251,322,381)	
Operating reserves balance - \$000	24	Line 24 + Line 23	(25,117,425)	(51,261,778)	(75,824,303)	(109,917,341)	(114,873,862)	(122,833,811)	(172,678,699)	(212,429,446)	(226,014,731)	(257,441,833)	(251,322,381)	(251,322,381)	

LIMIT OF CALCULATIONS - FINISHED															
TABLE 1: KENTON PROPERTY CORPORATION - Current as Dec 31															
Contract schedule, year ending Dec. 31, 1997 - Joint Geotechnical Fund Calculations - NAF System (1995)															
	Line#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
Contract generation - KRW															
Hydro	1	Manual Input	25,245,105	30,241,841	37,432,187	15,174,813	18,728,988	15,151,781	16,447,883	17,458,478	33,658,411	25,589,489	27,851,195	33,728,072	285,529,693
Hydro	2a	Manual Input	32,840	72,216	76,869	21,279	12,649	16,890	7,590	18,345	25,770	7,590	6,520	31,876	
Hydro	2b	Manual Input	8,775,890	4,777,890	9,825,209	8,881,893	7,291,572	1,763	5,819	38,419	38,419	7,148,020	8,742,705	45,181,385	
Total	2	Line 1 + Line 2	44,053,735	35,091,947	57,334,265	26,888,183	16,022,500	18,172,142	16,639,482	17,854,228	29,092,451	31,655,228	36,728,145	40,475,152	375,864,954
Forecast Generation - KRW															
Hydro	4	Manual Input	30,409,635	27,721,714	29,285,176	23,164,849	24,702,116	20,618,822	20,771,558	20,471,838	31,283,815	22,642,878	22,795,128	23,735,138	350,080,546.00
Hydro	4a	Manual Input	30,300	25,800	26,000	25,000	24,000	19,000	19,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Hydro	4b	Manual Input	11,609,646	15,861,265	17,927,980	11,884,238	1,602,313	1,203,810	1,368,954	1,269,812	1,447,875	3,311,765	7,865,221	11,851,268	84,265,222.80
Total	4	Line 4 + Line 5	42,049,680	36,115,882	35,951,781	35,073,257	26,225,131	21,757,642	22,142,512	22,342,342	33,072,290	26,144,641	30,799,419	31,616,266	635,045,818.80
Variances - KRW															
Hydro and other	7	Line 1 - Line 4	4,848,822	2,314,138	427,947	(10,945,785)	(2,844,585)	(14,883,052)	(14,381,444)	(13,010,212)	(11,312,764)	(6,594,349)	(13,722,511)	3,622,264	(70,814,822)
Hydro and other	8	Line 2 - Line 5	(5,514,156)	(8,253,276)	(2,813,263)	44,702,717	(8,208,953)	(1,201,783)	(2,263,404)	(1,342,882)	(1,348,543)	(3,352,899)	864,714	(6,123,468)	(18,813,464)
Total (variance)	9	Line 7 - Line 8	2,226,896	(5,939,138)	(4,241,248)	(15,347,604)	(16,155,132)	(19,084,835)	(15,644,848)	(14,358,119)	(13,652,678)	(10,188,315)	(6,857,215)	(2,501,144)	(198,628,286)
Forecasted total generation - KRW															
Forecast of savings to a maximum of forecast amount (based on sample 1 - year, 0 = nil)	10	Manual Input													
NET generation requirement at long term average hydro capacity															
Forecast generation	11	Line 5	11,378,448	10,897,265	11,832,693	11,664,298	8,902,201	1,289,019	1,348,854	1,389,543	1,442,476	5,811,795	2,885,233	11,851,268	84,265,222.80
Forecast generation	12	Line 5	2,226,896	(5,939,138)	(4,241,248)	(15,347,604)	(16,155,132)	(19,084,835)	(15,644,848)	(14,358,119)	(13,652,678)	(10,188,315)	(6,857,215)	(2,501,144)	(198,628,286)
Total hydro	13	Line 11 + Line 12	14,168,112	6,958,126	7,591,445	(4,753,343)	(8,852,931)	(17,795,816)	(14,296,994)	(12,974,474)	(12,166,865)	5,558,479	16,878,014	25,342,443	64,636,936.80
Forecast hydro	14	Line 13 if Line 10 = 0 - other = 0	14,168,112	6,958,126	7,591,445	(4,753,343)	(8,852,931)	(17,795,816)	(14,296,994)	(12,974,474)	(12,166,865)	5,558,479	16,878,014	25,342,443	64,636,936.80
Maximum savings available	15a	Line 5	11,378,448	10,897,265	11,832,693	11,664,298	8,902,201	1,289,019	1,348,854	1,389,543	1,442,476	5,811,795	2,885,233	11,851,268	84,265,222.80
Forecast hydro	15b	Line 5	8,925,200	4,277,938	6,958,268	6,861,457	1,298,230	2,263	82,010	8,813	86,639	257,679	1,149,829	6,747,710	45,181,385.80
Contracted generation															
Contracted generation (KRW)	16	Line 14a Line 15b (see line 14a)	6,445,622	2,314,138	427,947	(9,821,626)	(3,295,339)	3,271	3,271	3,271	3,271	3,271	3,271	3,271	3,271
Standard deviation (KRW)	17	Manual Input													
Standard error - 90% limit	18	Line 16/18 x 1.28	1,304,904	822,362	117,802	(1,248,576)	(424,186)	0.590	0.590	0.590	0.590	0.590	0.590	0.590	0.590
Standard error - 95% limit	19	Manual Input	8,2663	0.2663	0.2663	0.2663	0.2663	0.2663	0.2663	0.2663	0.2663	0.2663	0.2663	0.2663	0.2663
Forecasted net generation															
Forecasted net generation (KRW)	20	Manual Input	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
Forecasted net generation (KRW)	21	Line 16 + Line 17	386,371.52	144,959.74	34,673.69	(547,544.22)	(103,283.54)	-	-	-	(25,556.18)	(255,353.87)	(316,791.71)	(316,791.71)	(316,791.71)
Forecasted net generation (KRW)	22	Line 18 + Line 19	77,453.16	37,028.21	6,962.75	(103,766.72)	(22,775.37)	-	-	-	(5,775.62)	(58,209.62)	(72,761.23)	(72,761.23)	(72,761.23)
Forecasted net generation (KRW)	23	Line 20 + Line 21	463,724.68	21,881.13	41,635.73	(651,310.94)	(126,058.91)	-	-	-	(31,331.80)	(313,563.49)	(389,552.94)	(389,552.94)	(389,552.94)
Forecasted net generation (KRW)	24	Line 22 + Line 23	27,675.88	28,437.27	(24,802.97)	(69,034.63)	(47,305)	-	-	-	(1,145,482)	(1,145,482)	(1,145,482)	(1,145,482)	(1,145,482)
Forecasted net generation (KRW)	25	Line 24 + Line 25	470,240.89	11,254.14	(2,769.28)	(857,874.46)	(122,866.46)	-	-	-	(34,380.62)	(377,961.11)	(377,961.11)	(377,961.11)	(377,961.11)
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	26	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	27	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	28	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	29	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	30	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	31	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	32	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	33	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	34	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	35	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	36	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	37	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	38	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	39	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	40	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	41	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	42	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	43	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	44	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	45	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	46	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	47	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57
Forecasted net generation (KRW)															
Forecasted net generation (KRW)	48	Line 26 + Line 27 + Line 28	5,188,488.41	3,389,125.98	3,225,359.73	2,887,270.28	3,573,718.19	3,573,718.19	2,487,485.03	2,228,778.59	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.57	2,227,480.5

TABLE 2: THE YUKON ELECTRICAL COMPANY (MTRC) - Actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1997 - Diesel Conversion Fuel Distribution - WAF System (1995)															
	Line #	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
Actual generation - Mwh															
Hydro	1	Manual input	480,843	532,720	522,640	891,710	801,290	730,610	484,420	305,050	331,200	519,850	565,000	705,800	8,343,240
Thermal generation - Mwh															
Hydro	2	Manual input	857,091	850,368	785,831	819,009	798,243	829,380	636,538	875,441	865,903	847,000	819,400	840,944	10,041,844
Variances - Mwh															
Hydro	3	Line 1 - Line 2	336,421	117,696	166,840	219,895	5,047	88,889	371,170	109,701	154,100	327,900	272,800	128,144	3,698,509
Permitted power exchange (Mwh)															
Hydro	4	Line 3 if allowed as storage	336,421	117,696	166,840	219,895	5,047	-	-	-	-	-	122,888	128,144	1,358,875.00
Standard efficiency															
Line 17	17	Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Line 18	18	Line 18	1198,830	185,618	1708,090	88,229	1,900	-	-	-	-	803,340	137,280	609,605.20	609,605.20
Line 19	19	Line 19	6.2903	0.2903	0.2903	0.2903	0.2903	0.2903	0.2903	0.2903	0.2903	0.2903	0.2903	0.2903	0.2903
Fuel storage (Mwh) - 1998															
Line 19 + Line 18	20	Line 19 + Line 18	21,830.26	26,340.00	27,181.70	25,426.90	400.81	-	-	-	-	-	12,803.32	11,803.32	148,188.50
Line 21 + Line 4	21	Line 21 + Line 4	8,244.24	5,085.10	27,408.41	3,116.29	80.76	-	-	-	-	-	21,581.80	2,210.20	26,210.20
Line 20 + Line 21	22	Line 20 + Line 21	27,874.88	20,427.77	144,608.07	28,543.19	481.57	-	-	-	-	-	21,445.42	13,723.60	177,898.50
Operating reserves															
Line 25 after input	23	Line 25 after input	-	17,874.90	35,402.70	11,328.90	143,682.80	143,189.50	143,189.50	143,189.50	143,189.50	143,189.50	143,189.50	1194,844.90	1194,844.90
Line 22 + Line 23	24	Line 22 + Line 23	27,874.88	68,407.70	115,538.90	143,682.80	143,189.50	143,189.50	143,189.50	143,189.50	143,189.50	143,189.50	143,189.50	127,874.88	127,874.88

THERMOCALCULATIONS															
TABLE 3: THERMOCALCULATIONS - actual to Dec 31															
Continuity schedule, year ending Dec 31, 1999 - Diesel Generation Fuel Calculations - WAS System (0000)															
			JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Line#															
Actual generation - kWh	1	Month total	36,233,481	21,433,141	22,326,425	18,089,692	18,141,811	18,945,187	18,100,899	18,721,131	18,145,845	20,642,591	22,888,581	24,840,131	262,810,898
Hydro	1a	Month total	14,000	31,000	20,000	31,570	22,370	13,710	17,800	22,280	23,130	23,130	13,310	14,330	250,830
Wind	2	Month total	8,526,120	19,270	19,270	1,880	1,880	2,478	897,262	2,840	422	4,208	14,440	17,190	7,198,130
Total	3	Line 1 + Line 2	42,862,770	21,464,221	22,377,615	18,112,162	18,166,041	19,049,525	18,721,081	18,743,331	18,146,333	20,647,039	22,902,431	24,857,321	269,979,858
Forecast Generation - kWh															
Hydro	4	Month total	35,400,872	22,271,174	26,882,170	23,818,498	24,702,218	20,858,872	20,771,656	20,871,495	21,793,815	22,680,478	20,765,228	28,276,138	351,087,690.00
Wind	4a	Month total	30,000	28,000	28,000	25,000	24,000	15,000	16,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Wind	5	Month total	11,878,645	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Total	6	Line 4 + Line 5	47,279,517	32,912,442	38,710,023	35,682,771	34,254,229	22,177,845	22,123,010	22,342,842	25,605,610	38,576,689	41,856,248	113,392,340.00	435,383,912.00
Transmission - kWh															
Hydro and wind	7	Line 1 - Line 4	5,817,017	8,293,047	5,494,445	4,373,713	4,053,823	7,891,657	7,999,405	7,900,000	6,953,026	7,919,641	12,120,910	6,583,893	107,308,242.00
Wind and wind	8	Line 2 - Line 5	6,520,516	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Total Transmission	9	Line 7 - Line 8	12,337,533	18,934,315	17,322,298	16,237,986	15,606,034	9,093,867	9,345,059	9,382,675	10,764,821	15,815,851	24,002,118	15,067,786	191,604,464.00
Forecast demand - kWh															
Forecast of demand to a maximum of forecast demand	10	Month total	1												
Forecast of demand to a maximum of forecast demand	11	Month total	11,828,444	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	12	Month total	286,201	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791	18,846,791
Forecast of demand to a maximum of forecast demand	13	Line 11 + Line 12	12,120,645	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	14	Line 13 + Line 12 + 1 other = 0	12,120,645	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	14a	Line 13 + Line 12 + 1 other = 0	11,828,444	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Actual demand generation	15	Line 7	6,520,516	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Diesel Generation Fuel Calculations (0000)															
Forecast of demand to a maximum of forecast demand	16	Line 14 + Line 15 (Line 14)	6,517,017	8,293,047	5,494,445	4,373,713	4,053,823	7,891,657	7,999,405	7,900,000	6,953,026	7,919,641	12,120,910	6,583,893	107,308,242.00
Forecast of demand to a maximum of forecast demand	17	Month total	6,520,516	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	18	Line 18 + Line 17	12,337,533	18,934,315	17,322,298	16,237,986	15,606,034	9,093,867	9,345,059	9,382,675	10,764,821	15,815,851	24,002,118	15,067,786	191,604,464.00
Forecast of demand to a maximum of forecast demand	19	Month total	6,520,516	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand															
Forecast of demand to a maximum of forecast demand	20	Month total	6,520,516	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	21	Month total	6,520,516	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	22	Line 20 + Line 19	8,872,072	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	23	Line 21 + Line 22	538,078,935	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	24	Line 23 + Line 24	11,828,444	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	25	Line 24 + Line 25	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand															
Forecast of demand to a maximum of forecast demand	26	Line 26 + Line 25	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368	3,295,309,368
Forecast of demand to a maximum of forecast demand	27	Line 27	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	28	Line 28	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	29	Line 29	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	30	Line 30	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	31	Line 31	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	32	Line 32	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	33	Line 33	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	34	Line 34	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	35	Line 35	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	36	Line 36	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	37	Line 37	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	38	Line 38	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	39	Line 39	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	40	Line 40	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	41	Line 41	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	42	Line 42	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	43	Line 43	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	44	Line 44	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	45	Line 45	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	46	Line 46	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,210	1,345,654	1,482,675	3,811,795	7,896,211	11,861,208	84,296,222.00	84,296,222.00
Forecast of demand to a maximum of forecast demand	47	Line 47	675,127,177	10,641,268	11,827,853	11,864,273	9,552,211	1,202,21							

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Date \$1															
Customer schedule, year ending Dec 31, 1999 - General Contingency Fund Calculations - WAP System (1999)															
	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Market Input	721,790	560,445	685,790	667,695	557,790	369,160	260,080	263,780	279,980	245,230	271,870	467,900	5,561,281
Forecast generation - Mwh															
Hydro	2	Market Input	857,261	650,356	791,003	810,586	738,243	638,399	625,688	676,441	695,395	647,809	819,699	848,964	10,041,846
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(135,471)	(99,911)	(105,213)	(142,891)	(240,453)	(469,239)	(445,608)	(512,661)	(515,415)	(302,579)	(547,829)	(381,064)	(4,480,565)
Purchased power savings (loss) - Mwh	4	Line 2 if diesel on margin Line Table 1, line 16	(135,471)												(135,471.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard Price	18	Line 44, line 17	(26,461)												(26,461.18)
Standard price per Mw	19	YEC - Line 18	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965	0.2965
Load savings (loss) - \$000	20	Line 18 x Line 19	(12,793.84)												(12,793.84)
Variable O&M costs - \$000	21	YEC Line 21 x Line 4	(2,184.34)												(2,184.34)
Reserve loading (loss) - \$000	22	Line 22 x Line 21	(12,858.18)												(12,858.18)
Standard reserves	23	Line 23 price noted		(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)
Computation reserves (loss) - \$000	24	Line 23 x Line 23	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)	(12,858.18)

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YUKON ENERGY
CORPORATION
P.O. BOX 5920
WHITEHORSE
YUKON Y1A 5L7
Telephone (867)667-8382

EXHIBIT B-19

October 7, 1999

BY FAX: (867) 668-6213 & (867) 667-5059

Mr. Brian Morris, Chair
Yukon Utilities Board
P.O. Box 6070
#19, 10014 - 1st Avenue
Whitehorse, YT Y1A 5L7

Dear Mr. Morris:

Post-It® Fax Note	7671E	Date	09/10/07	# of pages	14
To	Intervenors	From	Darlene Morgan		
Co./Dept.		Co.	Rob McWilliam-Yec		
Phone #		Phone #	393-5336		
Fax #		Fax #	393-5323		

Re: Comments on the Diesel Contingency Fund Report

This letter provides additional comments on the Diesel Contingency Fund (DCF) Report that Yukon Energy filed with the Board on June 2, 1999.

In response to your letter of August 3, 1999, we include, as set out below, comments on the July 4, 1999 submission from the Utilities Consumers' Group (UCG). We also include, as Attachment A to this letter, additional background information on questions that may assist the Board in its review of the DCF filings for 1996 to 1998. Finally, as explained below, we also provide a correction to the row label text in certain tables of the DCF Report.

Correction to row label text - no impact on numbers or conclusions

We have noted an error in the row labeling of the tables attached to the DCF Report, which is corrected in the attached set of tables. The error (Variable Diesel O&M costs were incorrectly listed at 1.6¢ per litre instead of the correct value of 1.6¢ per kWh) does not change the values, calculations, balances or conclusions of the report. The error was also present in the text of the report at page 3, bullet (e) where the variable diesel O&M should also be listed as 1.6¢/kWh instead of 1.6¢ per litre. We have provided a corrected copy of Tables 1 through 3 as provided in the earlier report, and Yukon Energy's detailed Table 1 from each of the three years reviewed.

Comments Received to date on the DCF Report

The DCF Report has been provided to the Board pursuant to the 1996/97 Settlement Agreement. The Companies have complied with the terms of the Settlement Agreement in that they previously filed the appropriate reports with the Board for 1996 and 1997. The latest report provides the same information for 1998, along with certain revisions with respect to the earlier reports.

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October 7, 1999

Mr. Brian Morris, Chair
Yukon Utilities Board

Re: Comments on the Diesel Contingency Fund Report

Page 2

The Board has made provision to receive comments from any interested parties with respect to the recent DCF Report. We believe that the approach taken by the Board to date provides accountability that is consistent with the Negotiated Settlement Agreement. To date, the only written comments we have received from Intervenorors are those provided by the UCG letter of July 4, 1999.

In order to assist the Board we provide the following comments on the specific concerns raised by UCG:

- (a) **UCG requested further explanation and clarification of the Aishihik OIC and its effect on the DCF:** In response, additional information is provided below.

The Aishihik OIC (OIC 1997/13) affected the DCF only during the first quarter of 1997. Actual generation for the first quarter for YEC is shown in the DCF Report for 1997 after adjustments to reflect the impact of this OIC.

In total, 37,000 MWh was added to Hydro generation (actual) and 37,000 MWh was reduced from Diesel generation (actual) to reflect the impact of the OIC. In essence, the OIC compensated YEC for not using the bottom two feet of licensed water level storage at Aishihik Lake. The net effect of the above adjustments to the 1997 DCF Report ensured that the DCF was calculated on the assumption that the bottom two feet of licensed water level had been used to provide added Hydro generation during the first quarter of the year.

We note that this point was also set out in the response to UCG-YEC-1-8 in the 1998 Hearing, and was also addressed in our recent letter on fuel price variance 1997 finalization. As noted in the earlier response during the 1998 Hearing, the overall impact was to reduce YEC fuel related extra costs charged to the DCF by approximately \$2.95 million and to also reduce YEC variable O&M costs charged to the DCF by approximately \$0.59 million.

- (b) **UCG requested further explanation and clarification of the fire-related impacts on the DCF:** Further explanation and clarification is provided below.

The DCF Report provides extensive information and comment on fire-related impacts on the DCF. These are reviewed below:

- i) **1997 fire-related impacts:**

Actual diesel generation for YEC was required during three months of 1997 (October through December) due to reduced Hydro capability caused by the 1997

10/07/99 11:45 FAX 867 393 8327

YUKON ENERGY CORP.

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October 7, 1999

Mr. Brian Morris, Chair
Yukon Utilities Board

Re: Comments on the Diesel Contingency Fund Report

Page 3

fire at the Whitehorse Rapids hydro facility. These fire impacts were estimated in detail for each month in the tables attached to the Report, and commented on in Note 5 to the first table.

In essence, the 1997 DCF calculations for these months were revised to reflect the reduced Hydro capability resulting from the loss of Hydro generating units due to the fire. Under the terms of YEC's insurance policy there is a 30-day waiting period during which the cost of any fire-related diesel generation is not claimable.

Accordingly, the DCF drawdown for October and November 1997 due to the fire was charged to the YEC Reserve for Injuries and Damages (as detailed in the tables to the Report, this impact equaled \$403,052.95 for these two months combined). The DCF drawdown for December 1997 due to the fire has been charged to the fire insurance claim (as noted in the tables to the Report, this equaled \$113,114.28). In total, fire-related impacts equal to \$516,167.23 were removed from the costs charged to the DCF in 1997.

ii) **1998 fire-related impacts:**

During July 1998, YEC experienced a major forest fire that shut down the Faro transmission line for some time forcing YEC to generate diesel from the Faro plant. This diesel generation impact had nothing to do with Hydro generation capability, and thus cannot be charged to the DCF. As noted in the table attached to the Report titled "DCF Continuity Schedule 1996 - 1998", this forest fire impact on the DCF of \$58,182.00 for July 1998 has all been charged to the Reserve for Injuries and Damages.

(c) **UCG requested further explanation and clarification of the Company's assumption and decision of where and when they can use forecasted versus actual numbers:**

The DCF has been operated on the same basis as the Low Water Reserve Fund (LWRF) previously in place from 1991 through 1995, except for the material differences specified in the 1996/97 Settlement Agreement. In accordance with these procedures, the DCF Report sets out both actual and forecast generation numbers for the purpose of each year's calculations. This approach has been utilized throughout the history of the LWRF, and is explained further below. Additional background information is provided in Attachment A attached to this letter.

The DCF is intended to offset diesel generation cost changes for the WAF system that are caused solely by variances from long term average levels of WAF system hydro and wind generation. The forecast generation for hydro and wind reflects the appropriate long-

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October 7, 1999

Mr. Brian Morris, Chair
Yukon Utilities Board

Re: Comments on the Diesel Contingency Fund Report

Page 4

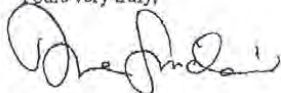
term average levels, as confirmed in the Negotiated Settlement Agreement. The forecast diesel generation for 1996 and 1997 reflects the balance of forecast generation requirement to meet the forecast load as set out in the GRA as approved by the Board.

The WAF diesel generation costs per kWh are based on the 1996 forecast as set out in the GRA (standard efficiency for diesel generation units use of fuel, YEC average WAF diesel fuel price forecasts, and the variable O&M diesel generation costs per kWh). For the 1998 DCF, the forecasts adopted for 1997 were retained. The same approach as adopted for 1998 will be used for any subsequent years until such time as the Board approves new forecasts.

The 1998 DCF Report noted that the Companies expect to prepare a submission to the YUB regarding the operation of the DCF for 1999 and beyond. When this submission is prepared, we would expect that the Board will seek comments from interested parties such as UCG and other Intervenor. This will provide additional opportunity to assess any issues related to the ongoing operation of the DCF for 1999 and subsequent years.

Based on the comments to date, we believe that the Board has the information required to approve the 1998 DCF as filed as well as the revised DCF schedules for 1996 and 1997. If you have any further questions, we would be pleased to assist you.

Yours very truly,



Rob McWilliam
President and Chief Executive Officer

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Attachments

c Intervenor

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ATTACHMENT A
General Questions and Answers re: DCF

Why does Yukon need a Diesel Contingency Fund (DCF)?

The Diesel Contingency Fund was created as a result of the Negotiated Settlement at the 1996/97 GRA. The DCF was to operate in the same manner as the earlier Low Water Reserve Fund (LWRF), established in the early 1990's, except for certain specified changes. The most notable adjustment was the use of long-term average water inflows, a change from the use of forecast hydro generation based on actual Aishihik water levels at the time of a rate application.

The question as to why a fund is needed at all was answered concisely in the report to the YUB in April 1997 prepared by the Accounting firm Stephen Johnson, as follows:

"In certain jurisdictions, electric power is generated at hydro dams or run-of-the-river hydro operations. Low Water Reserves have been established to protect customers against short-term fluctuations in the cost of electricity when more costly sources of generation, such as diesel, are substituted for hydro generation at times of low water conditions behind the dams or in the rivers. Simply, lower than average water level conditions generally result in higher diesel generation costs..."

"Given that the reserve is a vehicle for smoothing the cost fluctuations due to water level divergence from average, it is set up so that it can be drawn down to offset the costs of diesel generation in years of low water levels."

In addition, the DCF is set up so as to be replenished in years of high water levels. The result is better rate stability and predictability for both customers and utilities.

The 1996/97 Settlement Agreement provided for the operation of the fund as follows:

"The fund is to operate outside the rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund."

How does the DCF work?

The DCF operates based on a concept of "expected diesel generation". This expected diesel generation is calculated based on long-term average hydro generation and actual electricity consumption in any given period. It is the amount of diesel that one would expect to be required based on these two values. The DCF is either drawn down or replenished when actual diesel generation varies from the "expected" level due to water flow variances.

General Points Re: Approved DCF – Expected Diesel Generation

As noted earlier, the DCF as approved in the 1996/97 Settlement Agreement is to be operated on the same basis as the earlier LWRF, except for material changes specified in the 1996/97 Settlement Agreement. The concepts and calculation methods for "expected diesel generation" were already established in the LWRF, as previously approved by the Board, for months when the Faro mine was operating and diesel generation was clearly on the margin under forecast water flow conditions.

Attachment A – General Q & A re: DCF – Page 1

10/07/99 11:48 FAX 867 393 8327

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ATTACHMENT A - General O & A re DCF - Page 2

For simplicity, the following comments ignore wind generation variances, which became incorporated in the DCF as part of the 1996/97 Settlement Agreement.

General Points Re: Approved DCF when Faro Mine is Operating

To review the basis for "expected diesel generation" assessments when the Faro mine is operating, it is important to note that both the LWRF and the DCF address variances in the cost of diesel generation related solely to hydro generation variations from long-term averages that are due to hydro capability variances (e.g., water flows variances). The LWRF and DCF do not address other reasons for diesel generation cost variances (e.g., the DCF does not address diesel generation cost variances from forecasts due to fluctuations in sales or overall generation requirements, variances in fuel prices, or variances in diesel plant efficiencies or average O&M costs per kWh).

In order to determine how variances from long-term hydro generation capability affect diesel generation costs on a monthly basis, the LWRF specified that the following information would be used (the DCF assumes that forecast hydro generation is based on approved long-term averages):

- the forecast and actual WAF total generation requirement (WAF load)
- the forecast and actual WAF generation by source (hydro, wind, and diesel in the DCF).

The diesel generation variance from forecast can reflect a number of factors. For example, diesel generation can be affected by variances in WAF load from forecast as well as by diesel generation changes resulting from other factors not related to water flow variances.

Using an example, assume we forecast 50 GW.h of total WAF load, of which 10 GW.h is from diesel, and that actual usage is 60 GW.h of WAF load with 20 GW.h from diesel. Under these assumptions, the "expected diesel generation" methods adopted in the LWRF and retained in the DCF assume that this variance in diesel generation is not due to variance in water flows from long-term averages, despite the fact that diesel usage was 10 GW.h more than forecast. The process works likewise for a drop in system load. If we were to take the above case and argue that the diesel generation varied due to water flows it would not only be incorrect; it would elicit a payment for 10 GW.h of diesel generation costs from the fund – clearly inappropriate considering hydro and wind generation performed exactly as forecast at 40 GW.h.

Instead of using only diesel variance, the LWRF and DCF use a new figure, the "expected" diesel generation. In the above example we had forecast diesel generation at 10 GW.h plus a WAF system variance of +10 GW.h, so assuming everything else in the system operates as per forecast (including the level of water flows), the expected diesel generation would be 20 GW.h. This leaves a diesel savings/excess of 0 GW.h and no change to the fund balance.

"Expected diesel generation" is not directly affected by actual diesel generation. For example, assuming the same above forecast example (forecast 50 GW.h on the system with 10 GW.h from diesel generation) and actuals of 60 GW.h on the system with only 15 GW.h from diesel generation, the LWRF and DCF would retain the 20 GW.h expected diesel generation. In this case, however, the LWRF and DCF calculate diesel savings of 5 GW.h and the fund would thus be credited for the value of 5 GW.h of diesel generation cost savings. This is because the diesel generation variance from expected is -5 GW.h even though the diesel generation variance from forecast is +5 GW.h.

Attachment A - General O & A re DCF - Page 2

10/07/99 11:47 FAX 867 393 6327

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The LWRF and DCF also both ensure that diesel generation savings cannot exceed actual diesel generation.

It is not contemplated that "expected diesel generation" could ever be negative when the Faro mine is operating so long as YEC retains its current WAF hydro generation capability. Further, as reviewed below, the LWRF and DCF both assume that "expected generation" for diesel plant is zero when the Faro mine is not operating.

General Points Re: Approved DCF when Faro Mine Is Not Operating

Once the Faro mine is off the system, the expected WAF diesel energy generation drops to zero for the purpose of the LWRF or DCF. This is because the removal of this one load is sufficient to ensure, under current WAF load conditions and assuming long-term hydro generation capability, that WAF energy generation requirements can be met without diesel energy generation.

In actual fact, during significant periods of low water, such as the winter of 1998/99, diesel may be required for baseload WAF generation, and it is the intention of the DCF to address these variances from the "expected" level due to water flow variations. (Experience has shown that some minor level of diesel generation may also be needed, even when the Faro mine is closed, for peaking, voltage stability, or other purposes that are not affected by variances from forecast hydro generation capability. Accordingly, neither the LWRF nor the DCF consider these diesel generation requirements.)

These principles are reflected in the simple binary choice set out at line 10 of the DCF report table (YEC) for each month. When the Faro mine is operating, the "1" at line 10 indicates that diesel generation is assumed to be on the margin under long-term hydro generation conditions. When the Faro mine is not operating, the "0" indicates that diesel generation is assumed not to be on the margin under long-term hydro generation conditions.

The binary choice of "0" at line 10 dictates an "expected generation" for diesel of "0" at line 14. Under no condition can "expected generation" be set at less than "0" under the approved LWRF or DCF.

Even though the LWRF was completely suspended in 1993/94 when the Faro mine was closed, it was known that actual diesel generation may still be required under these conditions. Further, it was recognized during the 1993 GRA hearing that low water conditions could be one of the factors that necessitate such diesel generation – and that the LWRF would be expected to compensate for diesel costs incurred solely due to such low water conditions even when the Faro mine is closed. During the winter of 1998/99, with the Faro mine closed, actual low water conditions did result in baseload diesel being required, and the DCF was used in 1999 to address this variance.

The current DCF calculations recognize that small amounts of actual diesel generation may be required when the Faro mine is closed for purposes unrelated to variances from long-term hydro capability. In order to address this factor when the Faro mine is closed, the DCF is not activated in any such month when actual diesel generation does not exceed 250 MW.h (this assessment is done at line 16 of the DCF report table for YEC). Any such month with lower than 250 MW.h of diesel generation is assumed to have no diesel generation cost for the purposes of calculating the DCF.

Attachment A – General D & A re DCF – Page 3

10/07/99 11:48 FAX 867 393 6327

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How is 'Diesel on the Margin' Defined?

Diesel on the margin is a concept used to represent the significant impact that the operation of the Faro mine has on the Yukon electrical system. Diesel-on-the-margin is indicated in the calculations of the DCF at line 10 of the DCF report table for YEC, with a 1 indicating the Faro mine is operating and a 0 indicating the mine is shut-down. The definition of diesel on the margin at line 10 is not dependent on actual diesel generation.

Using a hypothetical example once again, assume WAF system load forecast at 50 GW.h with 10 GW.h of diesel and 40 GW.h of hydro. Assume the actual load is very low at 35 GW.h due to closure of the Faro mine (i.e., at a level where energy needs could be met solely by hydro generation at normal water flows). Finally, assume actual hydro generation is also low because of low water, at 30 GW.h. This means 5 GW.h of diesel was required. In this case, diesel is not "on the margin" at line 10 - actual load is 35 GW.h with a forecast hydro capability of 40 GW.h and there is thus no "expected" need for diesel generation. Since "expected" diesel generation is zero, the actual diesel at 5 GW.h is due to lower than average water flows, and the fund would be drawn down for the value of this generation, as would be expected based on low hydro generation.

Actual hydro generation also does not affect whether diesel is "on the margin" at line 10. It does play a significant role, however, in determining the charges or credits affecting the DCF at line 16.

Why Would the Fund Pay Out When Diesel is Less Than Forecast?

The rationale for drawing down the fund in some months when actual diesel is lower than originally forecast is the assessment that the actual diesel generation was required solely due to low water flow conditions (or other factors that similarly reduced hydro capability below long-term average capabilities).

Looking at the example used in the response to the above question, we can see that actual diesel at 5 GW.h is less than forecast diesel at 10 GW.h. However, actual hydro is also much lower than originally forecast. The variance in water flows is the cause of the 5 GW.h in diesel being needed (rather than no diesel being needed as would be "expected"). In this case the use of the DCF is called for.

There are conditions when the Faro mine is operating when the fund could also be drawn down even though actual diesel generation is less than forecast. Here again, the critical factor is "expected diesel generation" rather than only forecast diesel generation.

Conversely, there can be conditions, such as January, 1996, when diesel use is greater than forecast, but the fund is still credited due to hydro generation above what would be expected with average water flows.

Why Does the Calculation Use "Expected" Diesel Generation?

The above information outlines the calculation of the "expected" diesel generation. It is what one would expect to be required based on long-term average hydro and actual monthly system load. The principles were established earlier in the LWRF and have simply been retained in the DCF.

Attachment A - General R & R DCF - Page 4

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10/07/98 16:07 FAX 867 393 6327

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The rationale for not basing this number solely on forecast or actual diesel generation has been explained above.

Expected generation is always used as the starting point for diesel savings calculations at line 16 of the DCF table for YEC – whether diesel generation is on the margin or off the margin at line 10. The line 16 calculation deducts actual diesel generation from "expected generation", subject to the constraint noted at line 14a.

By definition, diesel being off the margin at line 10 means there is zero expected diesel generation at line 14.

In contrast, if simple diesel generation variance from actual was used, it would result in the fund adjusting for the costs of all variances from forecast – including load variances – not just those relating to water flows. It would be contrary to the purpose of the DCF, the former LWRF, and the intent of the 1996/97 Negotiated Settlement.

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Attachment A – General Q & A re DCF – Page 5

10/07/99 11:49 FAX 867 393 6327

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Table 1: DCF - Including Fire Related Diesel Generation:
(corrected September, 1999)

Line#			OCT-1997	NOV-1997	DEC-1997
Actual generation - Mwh					
1	Hydro	Manual Input	26,560,490	27,851,195	33,708,072
1a	Wind	Manual Input	17,840	6,530	21,370
2	Diesel	Manual Input	357,870	7,140,520	6,747,710
3	Total	Line 1 + Line 2	25,956,200	34,798,245	40,475,152
Forecast Generation - Mwh					
4	Hydro	Manual Input	32,502,678	30,785,228	29,775,158
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,611,765	7,995,231	11,851,208
6	Total	Line 4 + Line 5	36,144,441	38,780,457	41,655,366
Variance - Mwh					
7	Hydro and wind	Line 1 - Line 4	(8,934,346)	(3,137,501)	3,922,304
8	Diesel	Line 2 - Line 5	(3,253,895)	(854,711)	(5,103,436)
9	Total (favourable)	Line 3 - Line 6	(10,188,241)	(3,992,212)	(1,181,132)
Expected diesel generation - Mwh:					
Greater of (savings to a maximum of forecast diesel):					
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
(YEC generation requirement long term avg Hydro capability)					
11	Forecast generation	Line 5	3,611,765	7,995,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,181,132)
13		Line 11 + Line 12	(6,576,476)	4,003,018	10,670,014
14	Expected generation	Line 13 if Ln 10=1 otherwise = 0	-	4,003,018	10,670,014
14a	Maximum savings available	Line 5	3,611,765	7,995,231	11,851,208
15	Actual diesel generation	Line 2	357,870	7,140,520	6,747,710
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 > 250,000)	(357,870)	(3,137,501)	3,922,304
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	(96,461)	(845,888)	1,057,225
19	Standard price(\$ per litre)	Manual Input	0.2980	0.2980	0.2980
Basecase Buildup (drawdown)					
20	YEC Variable O&M costs(\$ per kWh)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 16 x Line 19	(26,558.10)	(250,355.67)	312,976.71
22	YEC Variable O&M costs	Line 20 x Line 16	(5,725.92)	(50,200.02)	82,756.86
23	YEC buildup (drawdown)	Line 21+22	(34,282.02)	(300,555.69)	375,735.57
24	YEC buildup (drawdown)	See YEC Table	0	(21,445.42)	(13,233.58)
25	Total buildup (drawdown)	Line 23 + 24	(34,282.02)	(322,001.11)	362,501.99

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Table 2: DCF - Excluding Fire Related Diesel Generation;
(corrected September, 1999)

Line#			OCT-1997	NOV-1997	DEC-1997
Actual generation - Mwh					
1	Hydro	Manual Input	25,840,460	31,500,795	34,886,872
1a	Wind	Manual Input	17,840	6,630	21,370
2	Diesel	Manual Input	97,870	3,290,920	5,589,910
3	Total	Line 1 + Line 2	25,938,300	34,798,245	40,475,152
Forecast Generation - Mwh					
4	Hydro	Manual Input	32,502,876	30,785,228	28,775,136
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,611,765	7,995,231	11,851,208
6	Total	Line 4 + Line 5	39,144,641	38,790,457	41,656,345
Variance - Mwh					
7	Hydro and wind	Line 1 - Line 4	(6,674,346)	712,089	5,103,104
8	Diesel	Line 2 - Line 5	(3,513,895)	(4,704,311)	(6,264,298)
9	Total (favourable)	Line 3 - Line 6	(10,188,241)	(3,992,212)	(1,161,194)
Expected diesel generation - Mwh:					
Greater of (savings to a maximum of forecast diesel):					
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
(YEC generation requirement long term avg Hydro capability)					
11	Forecast generation	Line 5	3,611,765	7,995,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,161,194)
13		Line 11 + Line 12	(6,576,476)	4,003,019	10,670,014
14	Expected generation	Line 13 if Ln 10=1 otherwise = 0	-	4,003,019	10,670,014
14a	Maximum savings available	Line 5	3,611,765	7,995,231	11,851,208
15	Actual diesel generation	Line 2	97,870	3,290,920	5,589,910
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 > 250,000)	-	712,089	5,103,104
17	Standard efficiency (kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 500 litres	Line 16/Line 17	-	191,940	1,375,500
19	Standard price (\$ per litre)	Manual Input	0.2960	0.2980	0.2990
Reserve Buildup (drawdown)					
20	YEC Variable O&M costs (\$ per kW.h)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 16 x Line 19	-	58,621.66	407,200.19
22	YEC Variable O&M costs	Line 20 x Line 18	-	11,393.58	61,849.66
23	YEC buildup (drawdown)	Line 21 x 22	-	86,215.24	489,649.85
24	YEC buildup (drawdown)	See YEC Table	-	(21,445.42)	(13,283.58)
25	Total buildup (drawdown)	Line 23 + 24	-	46,769.82	475,616.27

10/07/99 11:50 FAX 867 393 6327

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LINE 18-20-21-22-23-24-25

Table 3: DCF - Fire Impact (corrected September, 1999)			OCT-1987	NOV-1987	DEC-1987
Line#					
	Actual generation - Mwh				
1	Hydro	Manual Input	250,000	3,849,800	1,180,800
1a	Wind	Manual Input	0	0	0
2	Diesel	Manual Input	(250,000)	(3,849,800)	(1,180,800)
3	Total	Line 1 + Line 2	0	0	0
	Forecast Generation - Mwh				
4	Hydro	Manual Input	0	0	0
4a	Wind	Manual Input	0	0	0
5	Diesel	Manual Input	0	0	0
6	Total	Line 4 + Line 5	0	0	0
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	250,000	3,849,800	1,180,800
8	Diesel	Line 2 - Line 5	(250,000)	(3,849,800)	(1,180,800)
9	Total (favourable)	Line 3 - Line 6	0	0	0
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	0	0	0
12	Total variance	Line 8	0	0	0
13		Line 11 + Line 12	0	0	0
14	Expected generation	Line 13 if Ln 10=1 otherwise = 0	0	0	0
14a	Maximum savings available	Line 5	0	0	0
15	Actual diesel generation	Line 2	(250,000)	(3,849,800)	(1,180,800)
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 > 250,000)	357,870	3,849,800	1,180,800
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	96,461	1,037,828	318,275
19	Standard price(\$ per litre)	Manual Input	0.2980		
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs(\$ per kWh)	Manual Input	0.018	0.018	0.018
21	YEC Fuel savings (excess)	Line 16 x Line 19	28,555.10	307,177.33	94,221.48
22	YEC Variable O&M costs	Line 20 x Line 18	5,725.92	61,593.80	18,892.80
23	YEC buildup (drawdown)	Line 21+22	34,282.02	368,770.93	113,114.28
24	YEC buildup (drawdown)	See YECL Table			
25	Total buildup (drawdown)	Line 23 +24	34,282.02	368,770.93	113,114.28

Under the terms of the insurance policy there is a 30 day waiting period during which the cost of any fire related diesel generation is not claimable. Accordingly the DCF drawdown for October and November was charged to the Reserve for Injuries and Damages. The DCF drawdown for December has been charged to the fire insurance claim.

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2018-2019 CALCULATIONS - INTERGROUP														
Consolidated Distribution 1.000														
TABLE 1: TYPICAL SHOCKING COST DISTRIBUTION - actual to Day 81														
Company scheduled line ending Dec. 31, 1988 - Other Cost Entry Fund Calculations - YUB System (1988)														
	Line#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual Distribution - 1988														
Actual	1	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	14	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	2	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	17,777,778	213,333,332
Line#	3	2,717,679	2,680,010	2,684,800	2,689,226	2,693,990	2,698,446	2,702,902	2,707,358	2,711,814	2,716,270	2,720,726	2,725,182	32,666,672
Forecast Distribution - 1988														
Forecast	4	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	4a	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	120,000,000
Line#	5	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Line#	6	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Variance - 1988														
Variance	7	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	8	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	9	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Forecast Distribution - 1989														
Forecast	10	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	11	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	120,000,000
Line#	12	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Line#	13	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Variance - 1989														
Variance	14	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	15	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	16	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Forecast Distribution - 1990														
Forecast	17	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	18	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	120,000,000
Line#	19	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Line#	20	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Variance - 1990														
Variance	21	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	22	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	23	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Forecast Distribution - 1991														
Forecast	24	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	25	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	120,000,000
Line#	26	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Line#	27	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Variance - 1991														
Variance	28	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	29	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	30	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Forecast Distribution - 1992														
Forecast	31	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	32	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	120,000,000
Line#	33	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Line#	34	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Variance - 1992														
Variance	35	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	36	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	37	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Forecast Distribution - 1993														
Forecast	38	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	39	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	120,000,000
Line#	40	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Line#	41	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Variance - 1993														
Variance	42	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	43	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	44	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Forecast Distribution - 1994														
Forecast	45	20,495,457	20,454,888	20,460,544	20,466,104	20,471,664	20,477,224	20,482,784	20,488,344	20,493,904	20,499,464	20,505,024	20,510,584	239,342,736
Line#	46	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	120,000,000
Line#	47	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Line#	48	10,495,457	10,454,888	10,460,544	10,466,104	10,471,664	10,477,224	10,482,784	10,488,344	10,493,904	10,499,464	10,505,024	10,510,584	129,342,736
Variance - 1994														
Variance	49	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	50	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Line#	51	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000

Page 14

EXHIBIT B - 17

AN ORDER IN THE MATTER OF the Public Utilities Act
Revised Statutes, 1986, c. 143, as amended

and

Yukon Energy Corporation and The Yukon Electrical Company Limited
Diesel Contingency Fund Reports

BEFORE:	B. Morris, Chair	)	
	G. Leslie, Member	)	
	C. Metz Murray, Member	)	
	D. Schmekel, Member	)	
	W. Shanks, Member	)	October 27, 1999

ORDER 1999-3

WHEREAS:

- A. The terms of the 1996/97 Negotiated Settlement approved by Board Order 1996-6 provided for the creation of a Diesel Contingency Fund ("DCF") to smooth customer rate changes and offset forecast diesel costs.
- B. The terms also provided that an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board is to direct the Companies on the additions and deletions to the fund.
- C. On June 6, 1999 Yukon Energy Corporation filed a report, detailing the changes to the Diesel Contingency Fund in 1998, together with revised reports for 1996 and 1997. The filing also included, for convenience, copies of relevant DCF tables for The Yukon Electrical Company Limited.
- D. On June 17, 1999 the Board distributed copies of the report to interested parties for comment.
- E. On July 4, 1999 the Utilities Consumers' Group ("UCG") responded with some preliminary concerns and requested a full review of this report with a similar process to rate hearings; interrogatories and responses to/from the Companies to the various intervenor concerns. No other comments were received.

- F. The Board forwarded the UCG concerns to the Companies but noted that the Board had the ultimate jurisdiction over the DCF.
- G. On October 7, 1999 Yukon Energy Corporation provided comments on the submission from the Utilities Consumers' Group and additional information to assist the Board in its review.
- H. The Board has reviewed the material and finds that approval of the report is in the public interest.

NOW THEREFORE the Board orders that:

- 1. The Board approves the additions and deletions to the Diesel Contingency Fund for 1996 to 1998 as filed.

Dated at the City of Whitehorse, in the Yukon Territory, this 3rd day of November 1999.

BY ORDER



Brian Morris
Chair

Page 3

1 **TOPIC:** ERA Establishment

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-2, PDF page 30

4
5 **QUOTE:** The ERA was established in 1993, when ST hydro generation
6 forecasts were still being adopted for GRA purposes, as a
7 retrospective payment calculation integrated into the wholesale rate
8 (RS 42), designed to ensure that YECL received a full pass-through
9 of all incremental costs or savings of diesel generation attributable to
10 higher or lower than forecast wholesale demand. As with the DCF
11 and its precedent fund (the LWRF), the ERA was only active during
12 the 1990s when the Faro Mine was in operation which resulted in
13 diesel generation accounting for 100% of any generation change due
14 to firm load changes. (Emphasis added)

15
16 **PREAMBLE:**

17
18 **QUESTION:**

- 19
20 a) YECL is referred to in the quote. Should it refer to YEC? Please explain.
21
22 b) When the quote refers to forecast wholesale demand, does it mean energy?
23 Is the ERA a demand charge or an energy charge? Please explain.
24
25 c) When the ERA was established, ST hydro forecasts were still used for GRA
26 purposes. Did the shift to LTA forecasts affect in any way the need or purpose
27 of the ERA? Please explain.
28

29 **ANSWER:**

30
31 **(a)**

32
33 No. The quotation cited is correct, the wholesale rate (RS 42), is designed to ensure that
34 YECL received a full pass-through of all YEC incremental costs or savings of diesel
35 generation attributable to higher or lower than forecast wholesale demand. This is a
36 requirement of OIC 1995/90, Section 7.

1 As reviewed in paragraph 17 of the Yukon Court of Appeal judgement, Section 7 of OIC
2 1995/90 directs the Board to fix rates of Yukon Energy for the wholesale customer that
3 are "...sufficient to enable Yukon Energy Corporation to recover its costs that are not
4 recovered from its other customers." A mechanism such as the ERA is required pursuant
5 to this OIC at least to enable YEC to recover diesel related costs (including related YEC
6 payments required to be made into the DCF) it actually incurs for generating the electricity
7 sold to its wholesale customer.

8
9 **(b)**

10
11 Yes. The quote referenced is referring to load measured as energy [not demand]. YEC's
12 Wholesale Rate Schedule 42 has never included a demand charge.

13
14 **(c)**

15
16 No, the shift in forecast methodology [i.e., shift from short term to LTA hydro generation
17 forecasts for GRA purposes] in the 1996/97 GRA had no bearing on the requirement for,
18 or operation of, the ERA as established in the 1993/94 GRA. As noted in (a) above, the
19 ERA is designed to ensure that YECL receives a pass through of all incremental YEC
20 costs or savings of diesel generation attributable to higher or lower than forecast
21 wholesale demand. Regardless of the hydro forecast method adopted, this requirement is
22 operative when YEC's thermal generation costs vary from forecasts due to wholesale load
23 variances from forecast.

1 **TOPIC:** ERA Establishment

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-3, PDF page 31

4
5 **QUOTE:** Closure of the Faro Mine in 1998 lead to reduced demand and hydro
6 surplus conditions. Diesel generation was not responsive to load
7 changes under LTA hydro conditions. Under these conditions, LTA
8 hydro generation forecasts were not required for GRA purposes,
9 the DCF was inactive (except for interest income), and the ERA was
10 similarly not active.

11 ...

12 The LTA hydro forecast for GRA purposes, and the reactivated DCF
13 mechanisms, approved for the 2012-13 GRA differed from similar
14 1990 provisions in one key aspect - namely, the need in 2012-13 to
15 estimate a changing share of incremental load that is expected to be
16 supplied by LTA hydro generation (rather than the binary situation
17 when the Faro mine was connected to the system, i.e., variations in
18 generation then were either 100% diesel when the mine was
19 operating or 100% hydro when the mine was not operating).

20
21 **PREAMBLE:**

22
23 **QUESTION:**

- 24
25 a) Please explain why LTA hydro generation forecasts were not required after the
26 closure of the Faro mine? Would the principles underlying the DCF still apply?
27
28 b) For the proposed DCF in the 2012-2013 GRA, was the change from the previous
29 binary situation when the Faro mine was connected to the system, the only
30 change to the DCF, as it existed prior to the closure of the Faro mine? Please
31 explain.

1 **ANSWER:**

3 **(a)**

5 Please see response to YUB-YEC-2-3(b).

6 In summary, after the closure of the Faro mine, diesel was no longer considered to be on
7 the margin (i.e., changes in grid generation load were not expected to change diesel
8 generation requirements under LTA hydro forecasts) and the DCF and ERA were
9 therefore not active. LTA hydro forecasts were not relevant on either hydro grid for diesel
10 generation forecasts and related fuel costs for rate setting because there was surplus
11 hydro availability on the system relative to the system load.

13 **(b)**

15 The change to the DCF in the 2012/13 GRA addressed updated conditions on the hydro
16 grid system. As a result, the DCF change included more than the change from the previous
17 binary situation when the Faro mine was connected to the system.

18 The change from the previous binary situation when the Faro mine was connected to the
19 system means that variations in grid generation are no longer either 100% thermal or 100%
20 hydro (i.e., the earlier binary situation) but are now expected to be somewhere between
21 these two extremes. This change reflected a new relationship between grid generation
22 load and grid hydro generation capability at LTA water conditions.

23 Other changes to the DCF in the 2012/13 GRA reflected modifications as approved for the
24 2012/13 GRA thermal generation forecast and as directed by the Board in that proceeding
25 (and the subsequent DCF/ERA proceeding), including the expansion of the hydro grid
26 (i.e., connection of the WAF and Mayo Dawson hydro grids), changes to the hydro
27 facilities/licenses and operations, the expected use of LNG as well as diesel thermal
28 generation, inclusion of Fish Lake hydro and wind generation, and the YECSIM model
29 estimates of LTA hydro generation for the forecast grid generation load (including the
30 related water year records then available) which were used to provide the approved DCF
31 Term Sheet for year-end DCF determinations.

32 To be clear, the permanent closure of the Faro mine meant that the binary nature that
33 characterized the WAF and Mayo Dawson hydro grids throughout much of the 1980's and
34 1990's was no longer relevant. Specifically, during that earlier era the Faro mine was either
35 "on" or "off" and this load was so large (i.e., over 40% of total WAF generation) that it

1 would materially affect generation requirements. Accordingly, the following binary
2 outcomes occurred on the WAF hydro grid under these conditions:

- 3 • When the Faro mine was “on” diesel generation was on the margin and would vary
4 directly with changes in grid generation load; under these conditions, mechanisms
5 such as the DCF and ERA were triggered with changes in diesel generation equal
6 to 100% of the changes in WAF total generation.
- 7 • Conversely, when the Faro mine was “off”, variations in generation were 100%
8 hydro and the DCF and ERA were not triggered due to the large hydro surplus
9 available at LTA hydro generation under that grid generation load condition.

10 The permanent closure of the Faro mine was not “a change to the DCF” as assumed in
11 the question, but has resulted in the following key changes to how the DCF operates today:

- 12 • Given the forecast integrated grid load, thermal generation is now expected in each
13 year to be required at LTA hydro generation.
- 14 • Under the grid conditions as of 2012-13, a changing share of incremental load is
15 expected to be supplied by LTA hydro generation, i.e., variations in grid generation
16 are not either 100% thermal or 100% hydro (i.e., the earlier binary situation) but
17 are now expected to be somewhere between these two extremes.

18 Yukon Energy noted in the 2012/13 GRA that a number of updates to the DCF were
19 required prior to its reactivation in order to fully reflect changes that had occurred on the
20 integrated grid since the permanent closure of the Faro mine in 1998. These were
21 summarized in Appendix 3.2 of the 2012/13 GRA. The Purpose and Function section of
22 the DCF Term Sheet as provided in Attachment 3.2 of the 2012/13 GRA noted as follows:

23 *For the purposes of updating the Fund to address circumstances in 2012, the*
24 *following additional adjustments are required: (1) the Fund needs to be amended*
25 *to address the new interconnected system (i.e., not reference only “WAF” system*
26 *generation and instead reference all interconnected grid hydro operated by YEC);*
27 *(2) the Fund needs to be amended to address incremental costs for any fossil fuel*
28 *used to displace diesel fuel (e.g., liquefied natural gas or LNG, as well as*
29 *incremental costs for diesel fuel).*

30 Attachment 3.2 of the 2012/13 GRA also noted the following in the DCF Term Sheet as
31 regards changes to the LTA (footnotes are part of what was in the original attachment):

1 The Fund currently assumes that the quantum of diesel generation costs
2 in rates is determined using the long-term average water expected to be
3 available for generation.

4 The last approved long-term average hydro and wind on the YEC WAF grid
5 for the DCF as established in the 1996/97 GRA is set out below¹:

- 6 1. Aishihik Facility - 105 GWh/yr.
- 7 2. Whitehorse Rapids - 246 GWh/yr.
- 8 3. YEC wind generation - 0.3 GWh/yr.

9 **UPDATE:** *The previous approach of setting a single value for the long-*
10 *term average hydro is not suited to today's system. At the range of grid*
11 *loads relevant today and current hydro capabilities, it is necessary to*
12 *recognize that long-term average hydro capability varies with variations in*
13 *annual grid loads. Additional variation can occur regarding month-by-*
14 *month estimates of long-term average hydro and wind generation in years*
15 *when, for at least some months, diesel is not on the margin.*

16 *The following changes are required:*

17 **1. Updates based on changes to grid system**

- 18 a. *Mayo facility long-term average hydro updated to include*
19 *existing conditions and licences with regards to Mayo A and*
20 *Mayo B.*
- 21 b. *Aishihik facility long-term average hydro based on existing*
22 *conditions and licences, including Aishihik Third Turbine.*
- 23 c. *Wind generation as forecast in the last approved GRA.*

24 **2. Formulaic approach** – *determine expected diesel generation based*
25 *on long-term average water-based hydro generation that is forecast*
26 *using a formulaic relationship to load in each year (including non-test*
27 *years) rather than a fixed value as historically done².*

¹ The 2008/2009 GRA noted Yukon Energy's long-term average hydro generation capability from its Whitehorse and Aishihik plants on the WAF system, as estimated in the 1996/1997 General Rate Application when the Faro mine was assumed to be fully operational and all available hydro generation was expected to be fully utilized, approximated 351 GW.h per year.

² Long term average hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined based on power benefit model calculations based on 28 years of water record for the interconnected grid. As load grows a portion of the load growth is currently served (on average) by increased hydro output and the remainder by increased average diesel. This same analysis would apply to LNG if it replaces diesel on the grid.

- a. *Table 3.2-1 is adopted at this time to determine annual expected diesel generation prior to any new mine connections based on long-term average hydro generation at grid loads (net of wind and Fish Lake generation) ranging from 400 to 500 GW.h/year.*
- b. *The summary below (Example 3.2-1) provides an example of the determination of expected diesel generation at a grid load of 447 GW.h (net of wind and Fish Lake generation).*

Example 3.2-1: Expected Diesel Generation Example for the Load at 447 GW.h (net of Wind and Fish Lake)

- Step 1. Find the closest load from Column A that is less than 447 GW.h = 445 GW.h (Line 10).
- Step 2. Find the diesel generation from Column C = 28.4 GW.h (Line 10).
- Step 3. Find the difference between the given load (447 GW.h) and load from Step 1 (445 GW.h) = 2 GW.h
- Step 4. Apply the percentage from Column F (64%) to the difference from Step 3 (2 GW.h) = 1.27 GW.h
- Step 5. Add numbers from Step 2 (28.4 GW.h) and Step 4 (1.27 GW.h) = 29.67 GW.h

The expected diesel generation at 447 GW.h load is 29.67 GW.h.

Note: The load assumed the maximum load at 500 GW.h and the minimum load at 400 GW.h

- c. *Table 3.2-2 is adopted at this time to determine annual expected diesel generation in 2013 after such time as the Whitehorse Copper Tailings mine load is connected, based on long-term average hydro generation at grid loads (net of wind and Fish Lake generation) ranging from 400 to 500 GW.h/year and the annual load shape forecast with this new mine.*
- d. *Yukon Energy will provide an update to Table 3.2-2 when required in future to address material changes in long-term average hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.*
- e. **Monthly reporting** – *ensure the account can be managed on a monthly basis to permit financial reporting through use of a simple pre-determined monthly percentage distribution. Due to imprecision in forecast long-term average hydro monthly distributions it is possible that inappropriate values may arise during monthly estimating but these will not be part of final annual DCF calculations. Monthly calculations will be*

1 *a placeholder with ultimate final calculations performed only*
2 *on the annual values³.*

3 It is noted that the Term Sheet filed in the 2012/13 GRA was updated in the 2012/13 GRA
4 Compliance filing [filed in June 2013] as well as in the 2014 DCF/ERA Proceeding
5 compliance filing. The final 2012/13 DCF Term Sheet as approved in Board Order 2015-
6 06 is provided as Attachment 1 to this response, It has also been updated as part of the
7 2017/18 GRA.

³ There are limits to the ability to permit each month to have its own formula or polynomial, and differing monthly distributions may permit occasional odd values that resolve themselves in annual calculations. This same factor applied in the DCF calculations in the past.

**ATTACHMENT 1: FINAL 2012/13 DCF TERM SHEET [AS FILED APRIL 7, 2015
AND APPROVED IN ORDER 2015-06]**

ATTACHMENT 1: REVISED DCF TERM SHEET: YEC GRID & AEY FISH LAKE

PURPOSE

& FUNCTION: The Diesel Contingency Fund (“DCF”) operates to smooth customer rate changes from thermal (diesel, LNG and other thermal) generation cost impacts caused by fluctuation of hydro generation due to water conditions or changes in wind conditions.⁴

Yukon Energy Corporation (YEC) manages the DCF as a ratepayer “trust fund”. The Fund is only to be used for variations from long-term average (LTA) water and wind availability.⁵

LONG-TERM

AVERAGE: Board Order 2013-01 directed YEC to base its hydro and diesel energy requirements for YEC's GRA forecasts on 100 percent of long-term average (LTA) hydro generation.

The annual expected thermal generation requirements are determined based on the formulaic approach as provided below and takes into account variability from LTA in ATCO Electric Yukon's (AEY's) Fish Lake hydro generation and YEC hydro and wind generation.⁶

Formulaic approach – determine expected YEC thermal generation based on LTA water-based YEC hydro generation that is forecast using a formulaic relationship to load in each year (including non-test years):⁷

⁴ Appendix A to Board Order 2015-01, section 2.1.1.4, page 11.

⁵ Appendix A to Board Order 2015-01, section 2.1.1.4, page 14. The Board directed as follows: "Any application to utilize the fund in some other fashion will require the closing of the fund, the refunding of any balances to customers, and the direction for YEC to use short-term forecasts for its hydro generation in future GRAs."

⁶ AEY Fish Lake generation based on long-term average as approved by the Board Order 2014-06 at 8.73 GW.h and the last approved YEC wind generation (239 MW.h/year). The Fish Lake long-term average generation for 2012 and 2013 was at 4.38 GW.h due to unavailability of Unit #1.

⁷ Long-term average hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined in the 2012/13 GRA based on YEC's power benefit model calculations based on 28 years of water record for the interconnected grid. As load grows a portion of the load growth is currently served (on average) by increased hydro output and the remainder by increased average diesel. This same analysis would apply to LNG if it replaces diesel on the grid.

- 1 f. Table 1-1 is adopted to determine annual expected YEC
2 thermal generation based on long-term average YEC hydro
3 generation at YEC grid loads (net of expected wind and
4 expected Fish Lake generation) ranging from 390 to 475
5 GW.h/year, assuming mine loads connected as forecast in the
6 approved GRA for 2012.
- 7 g. Table 1-1 provides (below) an example of the determination
8 of expected YEC diesel generation at a grid load of 417 GW.h
9 (net of expected wind and expected Fish Lake generation).
- 10 h. YEC will provide the Board, for review and approval, an
11 update to Table 1-1 when required in future to address
12 material changes in LTA hydro system capability due to
13 changes in loads, installed capacity, licensing/permits or other
14 factors.

15 **DCF DIESEL**
16 **SAVINGS**
17 **(COSTS):**

18 YEC thermal generation savings (excess) are calculated on an
19 annual basis for the DCF based on expected thermal generation
20 less actual thermal generation.⁸ Costs for YEC thermal generation
21 savings (excess) are calculated based on the last approved
22 average cost of fuel for YEC per kWh based on the most recent
23 YEC GRA.⁹

24 Non-fuel O&M costs related to YEC thermal generation are not
25 included in the DCF calculations at this time. YEC will review and
report on this at its next GRA.

26 **DIESEL**
27 **ON THE MARGIN:**

28 The Board in Order 2015-01 noted that it does not consider diesel
29 being “on the margin” part of the criteria for invoking the DCF.
30 Based on current loads, expected load growth and LTA hydro
31 generation, the Board determined that there is a reasonable
expectation that under these conditions that diesel or “thermal”

⁸ Actual thermal generation excludes thermal generation charged to capital projects or to RFID.

⁹ The last approved average diesel fuel cost is based on YEC’s 2012/13 GRA at 28.71 cents/kW.h. The LNG generation is not in service yet. YEC will report to the Board (in its quarterly report) when LNG generation is in service, and provide (for Board review and approval) a proposed approach for inclusion of LNG in ongoing DCF determinations.

1 generation will form part of baseload generation thus making the
2 question of diesel being either "on the margin" or "off the margin"
3 moot.

4 **QUANTUM**
5 **& CAP:**

6 The Board in Order 2015-01 approved a "cap" for the DCF of +/- \$8
7 million as an acceptable balance between frequency of rider
8 applications and ability to handle material (drought) changes in
hydro availability.

9 In any year when the balance in the DCF fall outside of the +/- \$8
10 million range at fiscal year-end, YEC shall apply to the Board for
11 approval of a rate rider to dispense with the balance that is outside
12 of that range within 60 days of the fiscal year end.

13 The refund (when DCF balance exceeds \$8 million level) or
14 collection (when DCF balance is below -\$8 million level) is to be
15 made by way of a rate-rider to customers over next 12 month
16 period. YEC may apply and the Board may approve the
17 longer/shorter refund/collections period depending of the amount of
18 refund/collections required. The rider is applicable for all retail and
19 industrial firm sales in Yukon for both YEC and AEY.

20 **INTEREST:**

21 The Fund is to attract interest based upon the short/intermediate
22 term bond rates in which YEC may invest the Fund and any
23 negative balances would only attract interest at the lowest short-
term borrowing rate available to YEC through a line of credit.

24 **QUARTERLY &**
25 **ANNUAL**
26 **REPORTING:**

27 An annual report is required to be filed with the Board detailing
28 additions and deletions to the Fund and a forecast of water
29 conditions for the next year. The annual report to the Board is also
30 to include a proposed rate rider to refund/collect any amount that
31 exceeds the approved cap. The Board will direct YEC on the
additions and deletions to the Fund, and on any proposed rate rider.

32 Quarterly reports regarding the DCF calculations and DCF balance
33 updates will be provided to the Board based on interim
34 determinations prior to a fiscal year end. The quarterly DCF

- 1 calculations will be based on forecast loads for the year at the time
2 of calculation as the DCF table calculates the expected diesel
3 amount based on annual load, not quarterly.
- 4 Any interim determinations prior to a fiscal year end will only be
5 placeholders; only the year end determinations will in fact have
6 ongoing relevance for accounting and rate riders.
- 7 Examples of DCF calculations for 5 years are provided in Tables 1-2 and 1-3 below.

Table 1-1: Expected YEC Diesel Generation with LTA YEC Hydro Generation

Line Number	YEC Grid Load (GWh)	YEC Hydro Generation (GWh)	YEC Diesel Generation (GWh)	Increase in		Diesel as % of Increased Load
				Load (GWh)	Diesel Generation (GWh)	
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	390	387.0	3.0			
2	395	390.6	4.4	5.0	1.4	28%
3	400	394.0	6.0	5.0	1.6	32%
4	405	397.2	7.8	5.0	1.8	36%
5	410	400.2	9.8	5.0	2.0	40%
6	415	403.2	11.8	5.0	2.0	40%
7	420	405.9	14.1	5.0	2.3	46%
8	425	408.6	16.4	5.0	2.3	46%
9	430	411.1	18.9	5.0	2.5	50%
10	435	413.4	21.6	5.0	2.7	54%
11	440	415.5	24.5	5.0	2.9	58%
12	445	417.5	27.5	5.0	3.0	60%
13	450	419.4	30.6	5.0	3.1	62%
14	455	421.1	33.9	5.0	3.3	66%
15	460	422.6	37.4	5.0	3.5	70%
16	465	424.0	41.0	5.0	3.6	72%
17	470	425.3	44.7	5.0	3.7	74%
18	475	426.4	48.6	5.0	3.9	78%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding expected (GRA forecast) YEC Wind generation and actual less expected Fish Lake hydro generation.
2. The diesel generation and increase for the added load are based on polynomial equations derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The simulation model develops expected hydro plant capabilities for each load scenario. It reviews, by week, 28 "water years" of record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model outputs for this table are based on Aishihik operation rule at 10-year rolling average spring elevation no lower than 913.7 m and current Mayo Lake operation rule (no additional storage), Mayo B and Aishihik 3rd turbine are included.
5. The simulation model outputs are based on 2012 forecast load distributions [updated based on YUB Order 2013-01], and requires modifications when new mines or industrial loads are connected to the grid.
6. This table assumes max load at 475 GW.h and minimum load at 390 GW.h. If the load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

Example:

Expected YEC Diesel Generation for YEC Grid Load at 417 GW.h (net of expected YEC Wind & expected AEY Fish Lake)

- Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 6).
 - Step 2. Find the diesel generation from Column C = 11.8 GW.h (Line 6).
 - Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h
 - Step 4. Apply the percentage from Column F (Line 7, 46%) to the difference from Step 3 (2 GW.h) = 0.92 GW.h
 - Step 5. Add numbers from Step 2 (11.8 GW.h) and Step 4 (0.92 GW.h) = 12.72 GW.h
- The expected diesel generation at 417 GW.h load is 12.72 GW.h.

Notes:

The load assumed the maximum load at 475 GW.h and the minimum load at 390 GW.h.

Yukon Energy Corporation
2017 – 2018 General Rate Application
YUB-YEC-2-5

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Table 1-2: DCF Operation Example for 5 Forecast Years

Line	Activity	Year 1	Year 2	Year 3	Year 4	Year 5
A	DCF Opening Balance ¹ (\$000s)	\$902	\$1,764	\$2,753	\$4,093	\$2,258
B	Yukon Grid Generation ²	414,283	425,117	445,500	455,600	469,730
C	AEY Fish Lake ²	8,730	8,730	8,900	7,000	8,730
	YEC Grid Generation ²					
D	Assumed actual YEC Hydro (MW.h)	400,315	407,149	418,100	413,400	425,762
E	Assumed actual YEC Diesel [net of capital, insurance, etc.] (MW.h)	5,000	9,000	18,000	35,000	35,000
F	Assumed actual actual Wind (MW.h)	238	238	500	200	238
G=D+E+F	Total YEC Generation (MW.h)	405,553	416,387	436,600	448,600	461,000
H	Expected YEC Diesel Generation in Rates ³ (MW.h)	7,926	12,328	22,489	28,512	37,933
I=E-H	YEC Diesel Generation to be Included in DCF (MW.h)	-2,926	-3,328	-4,489	6,488	-2,933
J=I*\$0.2871	Incremental Diesel Generation Cost to Charge ⁴ (Refund) DCF (\$000s)	(\$840)	(\$956)	(\$1,289)	\$1,863	(\$842)
K=J	Total DCF operation for YEC					
	YEC pays to DCF Fund	\$840	\$956	\$1,289		\$842
	YEC withdraws from DCF Fund				(\$1,863)	
L=A+K	DCF Ending Balance (\$000s)	\$1,742	\$2,719	\$4,042	\$2,230	\$3,100
M	Interest on DCF Balance ⁵ (\$000s)	\$22	\$34	\$51	\$28	\$39
N=L+M	DCF Ending Balance ⁶ after Interest charge (\$000s)	\$1,764	\$2,753	\$4,093	\$2,258	\$3,139
O	Required Collections/(Refund) ⁷ (\$000s)	\$0	\$0	\$0	\$0	\$0

Notes:

1. DCF opening balance for Year 1 is 2011 actual ending balance of DCF account.

2. Assumed actual generation. Please see detailed calculations in Table 1-3.

3. Expected YEC diesel generation is calculated based on Updated Table 1-1 in Attachment 1. Please see detailed calculations in Table 1-3.

4. Diesel generation cost assumed at 28.71 cents/kW.h (based on 2012/13 GRA Compliance Filing average fuel cost).

5. Per the March 11, 1996 letter recording the settlements [provided as Exhibit B-16 in the 2008/2009 GRA] the DCF fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit. For this example used 1.25% based on Government of Canada Bond Yields for 3-year and 5-year issues.

6. Positive balances represent amounts to the benefit of ratepayers; negative balances are amounts owing to YEC.

7. YUB in its Order 2015-01 approved the DCF balance cap at +/- \$8 million. In any year when the balance in the DCF fall outside of the +/- \$8 million range at fiscal year end, YEC shall apply to the Board for approval of a rate rider to dispense with the balance that is outside of that range within 60 days of the fiscal year end.

2

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1 Table 1-3: DCF Formulaic Approach Operation Examples for 5 Load Forecast Cases

Line No	Fuel Cost per kW.h	28.71 cents/kW.h	Compliance Filing	Average Fuel cost	Notes
L1					
Calculation of Diesel Cost to Charge (Refund) DCF					
Year 1 - Actual Wind and Fish Lake at Forecast; Actual Diesel Generation Below Expected					
<i>Assumptions</i>					
L2	YEC Grid load	405,553 MW.h		assumed actual	
L3	Fish Lake	8,730 MW.h		assumed actual	
L4=L2+L3	Total Grid load	414,283 MW.h			
<i>Assumed Actual Generation Sources</i>					
L5	YECL Fish Lake	8,730 MW.h		assumed actual	
L6	YEC Hydro	400,315 MW.h		assumed actual	
L7	YEC Diesel (net of capital and insurance)	5,000 MW.h		assumed actual	
L8	YEC Wind	238 MW.h		assumed actual	
L9	Total Grid load	414,283 MW.h			
<i>Expected Generation Sources</i>					
L10	YECL Fish Lake (expected)	8,730 MW.h			YECL Fish Lake long term average hydro generation based on YUB Order 2014-06.
L11	YEC Wind (expected)	238 MW.h			YEC 2012/13 GRA
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	405,315 MW.h			
L13	Expected Base Diesel Generation at 405 GW.h	7,800 MW.h			Derived from updated Table 1-1, Attachment 1
L14=(L12-405 GW.h)x40%	Expected Incremental Diesel Generation at 315 MW.h above 405 GW.h	126 MW.h			40% of Grid Load between 405 GW.h and 410 GW.h is diesel -
L15=L13+L14	Total Expected YEC Diesel Generation	7,926 MW.h			Derived from updated Table 1-1, Attachment 1
L16=L15	Expected YEC Diesel Generation in Rates	7,926 MW.h			100% of long-term average
L17=L7	Actual YEC Diesel Generation	5,000 MW.h			assumed actual
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 2,926 MW.h			
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF (\$000s)	(\$840)			
Year 2 - Actual Wind and Fish Lake at Forecast; Actual Diesel Generation Below Expected					
<i>Assumptions</i>					
L2	YEC Grid load	416,387 MW.h		assumed actual	
L3	Fish Lake	8,730 MW.h		assumed actual	
L4=L2+L3	Total Grid load	425,117 MW.h			
<i>Assumed Actual Generation Sources</i>					
L5	YECL Fish Lake	8,730 MW.h		assumed actual	
L6	YEC Hydro	407,149 MW.h		assumed actual	
L7	YEC Diesel (net of capital and insurance)	9,000 MW.h		assumed actual	
L8	YEC Wind	238 MW.h		assumed actual	
L9	Total Grid load	425,117 MW.h			
<i>Expected Generation Sources</i>					
L10	YECL Fish Lake (expected)	8,730 MW.h			YECL Fish Lake long term average hydro generation based on YUB Order 2014-06.
L11	YEC Wind (expected)	238 MW.h			YEC 2012/13 GRA
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	416,149 MW.h			
L13	Expected Base Diesel Generation at 415 GW.h	11,800 MW.h			Derived from updated Table 1-1, Attachment 1
L14=(L12-415 GW.h)x46%	Expected Incremental Diesel Generation at 1,149 MW.h above 415 GW.h	528 MW.h			46% of Grid Load between 415 GW.h and 420 GW.h is diesel -
L15=L13+L14	Total Expected YEC Diesel Generation	12,328 MW.h			Derived from updated Table 1-1, Attachment 1
L16=L15	Expected YEC Diesel Generation in Rates	12,328 MW.h			100% of long-term average
L17=L7	Actual YEC Diesel Generation	9,000 MW.h			Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 3,328 MW.h			
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF (\$000s)	(\$956)			

2
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Table 1-3: DCF Formulaic Approach Operation Examples for 5 Load Forecast Cases (cont.)

Year 3 - Actual Wind and Fish Lake Higher than Forecast; Actual Diesel Generation Below Expected				
Assumptions				
L2	YEC Grid load	436,600	MW.h	
L3	Fish Lake	8,900	MW.h	
L4=L2+L3	Total Grid load	445,500	MW.h	
Assumed Actual Generation Sources				
L5	YECL Fish Lake	8,900	MW.h	
L6	YEC Hydro	418,100	MW.h	
L7	YEC Diesel (net of capital and insurance)	18,000	MW.h	
L8	YEC Wind	500	MW.h	
L9	Total Grid load	445,500	MW.h	
L10	YECL Fish Lake (expected)	8,730	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2014-06
L11	YEC Wind (expected)	238	MW.h	YEC 2012/13 GRA
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	436,532	MW.h	
L13	Expected Base Diesel Generation at 435 GW.h	21,600	MW.h	Derived from updated Table 1.1-1
L14=(L12-435 GW.h)x58%	Expected Incremental Diesel Generation at 1,532 MW.h above 435 GW.h	889	MW.h	58% of Load between 435 GW.h and 440 GW.h is diesel
L15=L13+L14	Total Expected YEC Diesel Generation	22,489	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	22,489	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation	18,000	MW.h	Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 4,489	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF (\$000s)	(\$1,289)		
Year 4 - Actual Wind and Fish Lake below Forecast; Actual Diesel Generation Above Expected				
Assumptions				
L2	YEC Grid load	448,600	MW.h	
L3	Fish Lake	7,000	MW.h	
L4=L2+L3	Total Grid load	455,600	MW.h	
Assumed Actual Generation Sources				
L5	YECL Fish Lake	7,000	MW.h	
L6	YEC Hydro	413,400	MW.h	
L7	YEC Diesel (net of capital and insurance)	35,000	MW.h	
L8	YEC Wind	200	MW.h	
L9	Total Grid load	455,600	MW.h	
Expected Generation Sources				
L10	YECL Fish Lake (expected)	8,730	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2014-06
L11	YEC Wind (expected)	238	MW.h	YEC 2012/13 GRA
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	446,632	MW.h	
L13	Expected Base Diesel Generation at 445 GW.h	27,500	MW.h	Derived from updated Table 1.1-1
L14=(L12-445 GW.h)x62%	Expected Incremental Diesel Generation at 1,632 MW.h above 445 GW.h	1,012	MW.h	62% of Load between 445 GW.h and 450 GW.h is diesel
L15=L13+L14	Total Expected YEC Diesel Generation	28,512	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	28,512	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation	35,000	MW.h	Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	6,488	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF (\$000s)	\$1,863		
Year 5 - Actual Wind and Fish Lake at Forecast; Actual Diesel Generation Below Expected				
Assumptions				
L2	YEC Grid load	461,000	MW.h	
L3	Fish Lake	8,730	MW.h	
L4=L2+L3	Total Grid load	469,730	MW.h	
Assumed Actual Generation Sources				
L5	YECL Fish Lake	8,730	MW.h	
L6	YEC Hydro	425,762	MW.h	
L7	YEC Diesel (net of capital and insurance)	35,000	MW.h	
L8	YEC Wind	238	MW.h	
L9	Total Grid load	469,730	MW.h	
Expected Generation Sources				
L10	YECL Fish Lake (expected)	8,730	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2014-06
L11	YEC Wind (expected)	238	MW.h	YEC 2012/13 GRA
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	460,762	MW.h	
L13	Expected Base Diesel Generation at 460 GW.h	37,400	MW.h	Derived from updated Table 1.1-1
L14=(L12-460 GW.h)x72%	Expected Incremental Diesel Generation at 762 MW.h above 460 GW.h	533	MW.h	72% of Load between 460 GW.h and 465 GW.h is diesel
L15=L13+L14	Total Expected YEC Diesel Generation	37,933	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	37,933	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation	35,000	MW.h	Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 2,933	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF (\$000s)	(\$842)		

1 **TOPIC: Thermal Generation Mix**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-3, PDF page 31

4
5 **QUOTE:** ... to assume that LTA thermal generation requirements (separate
6 from thermal generation maintenance activity requirements) are
7 supplied with a combination of 90% LNG and 10% diesel generation.
8

9 **PREAMBLE:**

10
11 **QUESTION:**

12
13 a) What happens if the actual thermal generation mix differs from the forecast?
14 Do ratepayers or YEC bear this risk? Please explain.
15

16 b) How are variances in actual fuel costs due to a change in the thermal
17 generation mix accounted for? Please provide a numerical example.
18

19 c) How and why was the 90:10 thermal generation mix developed?
20

21 **ANSWER:**

22
23 **(a) and (b)**

24
25 The quote references the proposed approach in the 2017/18 GRA, and the thermal
26 generation mix assumed in the GRA forecasts for LNG and diesel fuel costs.

27 YEC bears the risk of higher costs if the final thermal generation mix after the DCF
28 determinations differs from the 90:10 LNG: diesel mix assumed in the GRA test year
29 forecasts. This is explained below in the review of how variances in actual fuel costs due
30 to a change in the thermal generation mix are accounted for.

31 As noted in response to YUB-YEC-1-39, DCF Annual Reporting reports actual diesel and
32 LNG generation as recorded for a fiscal year, and thereby reflects actual limitations on
33 LNG unit operation during that year, including any of the limitations reviewed in Appendix
34 3.4 and YUB-YEC-1-36. This reporting by itself does not limit LNG or diesel unit operation.

DCF Annual Reporting also determines the following:

1. LTA (expected) thermal generation for the actual firm load based on the DCF Term Sheet table approved by the Board.
2. The gap for the year between LTA (expected) thermal generation and actual thermal generation that determines the amount that YEC pays into or receives from the DCF for the fiscal year (the “DCF Transfer”).
3. In determining the DCF Transfer amount, it is necessary to specify the portion assigned to LNG versus diesel generation. The current GRA Application proposes rules going forward as of January 1, 2017 for determining the LNG/diesel split for the DCF Transfer. The proposed approach for determining the DCF Transfer LNG/diesel mix focuses on setting YEC’s annual **overall** fuel mix costs as close as possible to the GRA approved assumptions (i.e. the proposed 90/10 LNG/diesel mix) adopted to set the approved revenue requirement and rates.

As reviewed in response to YUB-YEC-1-43(a), adoption of the actual fuel mix for actual generation versus the assumed 90/10 LNG/diesel fuel mix will have varying impacts depending on the actual fuel mix and its share of expected thermal generation in a fiscal year. The example set out in Tables 3.4-2 and 3.4-3 of Appendix 3.4 looks at a range of such potential situations over five years, indicating the impact of the proposed approach as summarized below to contrast with assuming the actual fuel mix in each year:

- Year 1 of example:
 - o Actual fuel mix assume 50/50 LNG/diesel (actual < expected by 9.9 GW.h).
 - o Proposed DCF Transfer 98/2 LNG/diesel; yields overall 90/10 LNG/diesel.
- Year 2 of example:
 - o Actual fuel mix assume 25/75 LNG/diesel (actual < expected by 14.4 GW.h).
 - o Proposed DCF Transfer 100/0 LNG/diesel; yields overall 83.7/16.3 LNG/diesel, i.e., YEC bears risk of higher costs due to final diesel share [after DCF determinations] exceeding 10% assumed in GRA forecast.
- Year 3 of example:
 - o Actual fuel mix assume 96.8/3.2 (actual < expected by 19.0 GW.h).
 - o Proposed DCF Transfer 88.9/11.1 LNG/diesel; yields overall 90/10 LNG/diesel.

- 1 • Year 4 of example:
 - 2 o Actual fuel mix assume 71.4/28.6 LNG/diesel (actual > expected by 42.1
 - 3 GW.h).
 - 4 o Proposed DCF Transfer 59/41 LNG/diesel; yields overall 90/10 LNG/diesel.
- 5 • Year 5 of example:
 - 6 o Actual fuel mix assume 60/40 LNG/diesel (actual > expected by 68.1
 - 7 GW.h).
 - 8 o Proposed DCF Transfer 46.7/53.3 LNG/diesel; yields overall 90/10
 - 9 LNG/diesel.

10 As reviewed in response to YUB-YEC-1-43 (b), the proposed approach will not allow the
11 LNG share of any transfer into or out of the DCF to exceed 100%. As a result, under
12 certain factual situations (e.g., the year 2 example in Table 3.4-3 as reviewed above), the
13 final fuel mix for the DCF Transfer will be 100% LNG and the expected overall generation
14 mix after the DCF Transfer will not equal the 90/10 LNG/diesel fuel mix assumed for the
15 Application. Under this situation, the proposed GRA rules for DCF determination of the
16 DCF Transfer fuel mix yield an overall 83.7/16.3 LNG/diesel mix, and YEC bears the full
17 risk of higher costs due to final diesel share [after DCF determinations] exceeding the 10%
18 assumed in the GRA forecast.

19 Absent the proposed procedures, in order to secure a 90/10 LNG/diesel mix would require
20 under certain factual situations an LNG share of any transfer to exceed 100%. Under the
21 above referenced example for year 2:

- 22 • Assumed actual thermal generation of 4 GW.h, with fuel mix 25/75 LNG/diesel.
- 23 • Assumed expected thermal generation of 18.446 GW.h.
- 24 • The transfer of funds to the DCF is based on 14.446 GW.h gap between expected
25 and actual thermal generation.
- 26 • The target 90% LNG would require 90% of expected, or 16.6 GW.h (or 15.6 GW.h
27 more than actual LNG generation).
- 28 • To achieve this target, the LNG share of the DCF transfer would need to equal
29 108% of the 14.446 GW.h to be transferred.

1 (c)

2
3 The basis for the 90/10 LNG/Diesel generation mix is outlined in Appendix 3.4 of the
4 2017/18 GRA as well as in the response to YUB-YEC-1-25; YUB-YEC-1-43; YUB-YEC-
5 1-36; YUB-YEC-1-39 and JM-YEC-1-13.

6 This approach is proposed to ensure that revenue requirement costs used to set rates
7 provide some recognition of the current limits on actual LNG ability to displace all diesel
8 generation (see response to YUB-YEC-1-25 for more detailed review). No such
9 LNG/diesel split was specified in prior GRA Test Year Revenue Requirement
10 determinations (see response to YUB-YEC-1-42).

11 As summarized in YUB-YEC-1-25, details on establishing the 90:10 LNG: Diesel
12 proportion are reviewed in Section 1.3 of Appendix 3.4 of the Application. This ratio is not
13 statistically based, but reflects experience and expectations related to thermal generation
14 to supply the long-term average (LTA) requirement over all water years.

15 Key points reviewed on this matter in Appendix 3.4 include:

- 16 • YEC's LNG Part 3 Application provided simulations and analysis to support the
17 assumption that the initial two LNG units (8.8 MW) would be expected to displace
18 all LTA diesel generation at LTA thermal requirements of up to 17 GW.h/year. This
19 assessment assumed operation of the LNG units as required during low water
20 conditions (i.e., during the water years accounting for the vast majority of the LTA
21 thermal generation requirement at grid loads then forecast) to enhance hydro
22 storage for use in wintertime.
- 23 • LTA thermal generation requirements on the grid remained below 17 GW.h in 2015
24 and 2016, and remain below 17 GW.h in each of the test years, indicating that an
25 assumption of 100% LNG displacement of LTA diesel generation during these
26 years would be consistent with the Part 3 determinations.
- 27 • Addition of a third LNG unit in 2019 will expand considerably the overall LNG
28 capability to displace LTA diesel generation on the grid.

- 1 • Actual LNG unit operation to date has been constrained by unit size at 4.4 MW
2 (see response to YUB-YEC-1-38 for review of these constraints¹); however, these
3 constraints are not considered to have a material impact on the ability of LNG (with
4 operation during low water conditions to enhance hydro storage) to supply overall
5 LTA thermal generation at the grid loads relevant to the Application.
6 o Appendix 3.4.2 (Figure 3.4-1 and Table 3.4-4) highlights the extent that
7 LTA thermal is affected by years with below average water levels.
8 o At a grid load of 420 GW.h/year, 75% of the thermal generation
9 requirement over 35 water years occurs in the 20% of the 35 water years
10 with the worst drought conditions, and less than 1% of this thermal
11 generation occurs in the 46% of the 35 water years with the best water
12 conditions.
13 • The Application proposes that LTA thermal generation be assumed, for revenue
14 requirement purposes at this time, to be supplied 90% by LNG-supplied natural
15 gas generation and 10% by diesel generation. This approach is proposed to
16 ensure that revenue requirement costs used to set rates provide some recognition
17 of the current limits on actual LNG ability to displace all diesel generation.

¹ In summary, the manufacturer recommends not running the existing 4.4 MW LNG units for loads below 2.6 MW, and for minimum time periods of less than 4 hours. Existing diesel units are therefore used for loads that are not suited for existing LNG unit operation, and these constraints affect ST LNG/diesel fuel mix at varying loads. In contrast, as reviewed in response to YUB-YEC-1-38, emergency response loads are excluded from LTA forecasts and LTA thermal generation at the GRA forecast grid loads are driven mainly by sustained thermal generation required during low water or drought conditions.

1 **TOPIC:** VGC PPA

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-5, PDF page 33

4
5 **QUOTE:** The PPA Application indicates a potential increase in grid loads
6 over the next decade sufficient to sustain material forecast thermal
7 generation at LTA hydro generation, e.g., prior to any enhanced
8 renewable generation being implemented, incremental YEC LTA
9 thermal generation at 65% to 75% of the incremental generation is
10 needed to supply the VGC mine power requirements. Since the
11 late 1980s, such grid loading magnifies thermal generation cost
12 impacts from load changes which in turn reinforces the
13 requirement for LTA hydro generation forecasts for GRA purposes,
14 LTA DCF-type thermal cost or contingency fund account
15 mechanisms, and the ongoing need for ERA wholesale rate
16 mechanisms. (Emphasis added)

17
18 **PREAMBLE:**

19
20 **QUESTION:**

- 21
22 a) The ERA only accounts for changes in wholesale loads from forecast. How is
23 YEC protected from changes in industrial loads? Please explain.
24
25 b) The ERA allows YEC to collect incremental thermal generation charges from
26 incremental wholesales of electricity above the last Board approved
27 forecast. YECL's (AEY) deferral account allows YECL to collect those
28 charges from all customers in Yukon. Would it be more efficient if YEC
29 applied for a rider for all Yukon customers to cover the cost of this
30 incremental thermal generation? Please explain.

31
32 **ANSWER:**

33
34 **(a)**

35
36 Yukon Energy is not protected from changes in industrial or retail loads.

1 Yukon Energy bears the risk for changes in industrial load as well as changes in its retail
2 customer load. It does not have a deferral account or other measures to mitigate cost
3 change impacts related to load changes for these customers. Please see response to
4 YUB-YEC-2-1(d).

5
6 **(b)**
7

8 In Yukon Energy's view this would not be more efficient and would in effect be contrary
9 to the established regulatory context in Yukon as reviewed in response to YUB-YEC-2-
10 1(d) wherein each utility bears the risk of thermal cost changes related to grid load
11 changes (and ratepayers are not charged for such changes through deferral accounts).

12 As reviewed in response to YUB-YEC-2-1(d), the approach taken in the 1990s when the
13 ERA was established jointly by the Companies ensured that each utility bore the load
14 related risk directly related to its customers, i.e., through the ERA the wholesale utility
15 bore the load related risk (or captured the benefits) related directly to changes in load for
16 its retail customers. No changes to retail rates were contemplated or enacted in the
17 1990s as a result of ERA charges or rebates to YECL.

18 Accordingly, prior to 2008 this risk was held by the utility as there was no deferral
19 account mechanism in place to pass this risk on to YECL's (AEY's) retail customers. The
20 provision for a Purchase Power Flow Through Account for YECL was approved by the
21 YUB in 2008, which in effect allowed YECL to defer and flow through ERA costs to
22 Yukon ratepayers. No actual deferrals or flow throughs have yet been approved by the
23 Board under this provision.

24 The current arrangements since 2008 enable the Board to retain regulatory review of
25 AEY's deferral account and to assess on an ongoing basis under what conditions, if any,
26 it is appropriate to flow through any charges or rebates to all Yukon customers. Yukon
27 Energy is not aware of any basis for assuming a YEC rider automatically applied to all
28 Yukon customers to cover the cost of incremental thermal generation related to AEY
29 hydro grid loads being more efficient than the current arrangement.

1 **TOPIC: Ratepayer Risks**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-7, PDF page 35

4
5 **QUOTE:** As reviewed below, these inter-relationships start from the
6 accepted premise that ratepayers bear the risk of low water
7 conditions as regards added costs for added thermal generation,
8 and that material instability in thermal generation costs due to
9 water availability therefore pose direct challenges to the stability
10 of rates that the Board would need to approve.

11
12 **PREAMBLE:**

13
14 **QUESTION:**

15
16 a) Please define “material instability”.

17
18 b) What does YEC mean by “direct challenges to the stability of rates”? Did the
19 Board make a determination as to a specific threshold that when breached leads
20 to instability of rates? Please explain.

21
22 **ANSWER:**

23
24 **(a) and (b)**

25
26 “Material instability” is not a specifically defined term. In the context of the general
27 statement referenced here, the term refers to the situations when low water conditions
28 (and, in particular, drought conditions) can severely restrict hydro generation relative to
29 LTA and result in high added thermal generation cost requirements to be reflected in
30 rates.

31 As reviewed in response to YUB-YEC-2-2(c), throughout YEC's GRA filings and related
32 Board decisions since 1989 rate stability risks have been recognized related to water
33 variances affecting hydro and thermal generation when overall hydro grid loads are at
34 levels that required thermal generation under LTA hydro conditions. These rate stability
35 risks reflect the regulatory principle adopted throughout this period that the risk of low
36 water conditions, as regards added costs for thermal generation, is borne by ratepayers.

1 As reviewed in responses to YUB-YEC-2-2(c) and YUB-YEC-2-3(c), the Board has
2 approved various measures (including the LWRF and the DCF) to address the direct
3 challenges noted to the stability of rates due to water variability. The Board has not,
4 however, made any determination as to a specific threshold that when breached leads to
5 instability of rates. However, as reviewed in response to YUB-YEC-2-3(c), the Board
6 expressed concerns in the early 1990s about rate instability when YEC used short-term
7 hydro forecasts to set rates, and directed YEC to assess use of LTA hydro forecasts in
8 order to yield greater rate stability.

9 Appendix 3.4 of the 2017/18 GRA filing, in Attachment 3.4.4, reviews the potential range
10 of thermal cost variance due to water conditions at various grid generation loads and
11 with varying DCF caps.

1 **TOPIC:** Yukon Hydro Grid Inter-relationship

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-8, PDF page 36,
4 Figure 2-1

5
6 **PREAMBLE:**

7
8 Figure 2-1 shows a contingency fund implementation post GRA.

9
10 **QUESTION:**

- 11
- 12 a) Please confirm if the use of a contingency fund can apply to either a
13 short-term or LTA hydro forecast.
14
- 15 b) If part (a) is confirmed, please explain why YEC has never requested a
16 contingency fund based on a short-term hydro forecast.
17
- 18 c) In Figure 2-1, the middle box states: 1. Ratepayers bear risk related to water
19 variability. Is this for all variations of water variability from forecast?
20
- 21 d) Can water variability be defined? Please explain. Does it refer to the total
22 amount of hydro generation possible or is it the amount available dependent
23 upon level of load?
24
- 25 e) Do all Canadian utilities that have hydro generation have a contingency fund
26 that passes risk of variation in water to customers? Please explain.
27
- 28 f) Could the ratepayer risk be mitigated? That is, could the contingency fund only
29 apply for variations above or below a certain level of forecast such as 10%?
30 Please explain.
31
- 32 g) Has YEC investigated methods to reduce risk related to water variability for
33 ratepayers? Please explain.
34
- 35 h) YEC (and YECL) has a deferral account for the price of fuel for thermal
36 generation. With the DCF or a similar contingency fund, is it accurate to state
37 that YEC's risk with respect to fuel volumes for thermal generation is

1 mitigated? Please explain.

2
3 i) If the statement in part (h) is accurate, should YEC's ROE be reduced to
4 reflect the risks borne by ratepayers? Please explain.

5
6 j) In the converse, if the Board determined that YEC should bear risks related to
7 water variability, how would that affect YEC's ROE?

8
9 **ANSWER:**

10
11 **(a) and (b)**

12
13 The assertion in question (a) is confirmed. Use of a contingency fund can apply to either
14 a short-term or LTA hydro forecast.

15
16 As outlined in Figure 2-1 of the Two Part ERA Application, whether a short-term or long-
17 term average forecast is used, if it is accepted that ratepayers bear forecast risk related to
18 water variability a contingency fund is considered necessary to mitigate ratepayer
19 impacts due to changes in water availability compared to forecast.

20
21 The assertion in question (b) is incorrect. The Low Water Reserve Fund (LWRF)
22 implemented in the early 1990s [approved in Order 1991-2] was a contingency fund that
23 operated during a period when short-term hydro generation forecasts were used in GRA
24 forecasts (e.g., 1991/92 GRA used a short-term forecast and 1993/94 GRA used a short-
25 term forecast). Please see response to YUB-YEC-2-2(c) for more details of filings and
26 Board Orders over this period.

27
28 **(c)**

29
30 Yes. To extent that thermal generation is affected, this is intended to apply to all
31 variations of water variability from GRA forecast. Please see response to YUB-YEC-2-
32 2(c) as regards the YEC past filings and Board Orders relating to ratepayers bearing
33 risks related to water variability relative to GRA forecasts.

1 **(d)**

2
3 Water variability has been defined for each contingency fund adopted to date for YEC
4 GRAs.

5
6 As reviewed in response to YUB-YEC-2-2(c), water variability affects thermal generation
7 costs only when grid loads require thermal generation at LTA hydro generation. In this
8 context, when considering GRA forecasts and year-end contingency fund
9 implementation, water variability refers to the amount of LTA hydro generation applicable
10 to the applicable grid load. See also YUB-YEC-2-2(a and b) for review of low water
11 condition impacts on thermal generation at different grid loads with the current hydro
12 generation capability.

13
14 For the purposes of the current DCF, water variability may therefore be defined as a
15 change from the LTA available hydro generation that would otherwise be expected
16 based on assumed operating conditions for the Yukon Integrated System.

17
18 The DCF Term Sheet defines hydro generation variability with regard to the LTA forecast
19 and various grid loads as required for current 2017-18 GRA purposes.¹

20
21 The DCF Term Sheet notes (footnote 12) that long term average hydro generation in this
22 table under any set of assumed grid generation load and grid generation capacity and
23 licence conditions is determined based on current YECSIM power benefit model
24 calculations (based on 35 years of water record) for the interconnected grid and updated
25 reservoir and generation station water flow requirement changes (as noted in Appendix
26 3.4 of the Application). As load grows a portion of the load growth is served (on average)
27 by increased hydro output and the remainder by increased average thermal generation
28 (diesel or LNG).

29
30 **(e)**

31
32 No. The basic premise that ratepayers bear the cost risks related to hydro is applicable
33 for all Canadian utilities that have hydro generation, and in each instance measures are
34 adopted that attempt to enhance long-term rate stability. However, all of these utilities do
35 not have a defined contingency fund that passes risk of variation in water to customers.

¹ The DCF Term Sheet is provided as Attachment 3.4.1 of the 2017/18 GRA.

1 Canadian utilities that have hydro generation each address ratepayer risk related to
2 variation in water differently taking into consideration the context specific to that
3 jurisdiction. Not all utilities with hydro generation have a contingency fund to mitigate
4 ratepayer risks related to hydro generation.

5
6 Yukon Energy reviewed rate stabilization mechanisms used in other jurisdictions
7 including NWT, Manitoba and Newfoundland as part of rebuttal evidence filed during the
8 2014 DCF/ERA proceeding. See YUB-YEC-2-9 - Attachment 1. It is understood that the
9 approach taken in each jurisdiction, while context specific, acknowledges that water
10 variability is a ratepayer risk. The review highlighted the need to consider the relevant
11 context in Yukon [that led to the development of the DCF] as well as the relevant context
12 in other jurisdictions [which underlies the specific approaches adopted to address water
13 variability risk in each particular jurisdiction].

14
15 Relevant experience from other hydro-based jurisdictions that Yukon Energy is familiar
16 with is summarized below.

17
18 ***Northwest Territories***

19
20 Northwest Territories Power Corporation (NTPC) has a dedicated Fuel and Water Rate
21 Stabilization Fund (RSF) to address changes from GRA forecast for hydro generation
22 water availability and fossil fuel prices, recognizing that the risks for each such change
23 are ultimately born by ratepayers rather than by the utility.²

24
25 The consolidation of the fuel and water stabilization funds was approved by NWT PUB
26 by Decision 1-2013 respecting NTPC's 2012/13 and 2013/14 GRA. The purpose of the
27 RSF is to flow through to customers, subject to a \$2.5 million threshold, variances in fuel
28 prices and purchased power prices relative to the GRA forecast, as well as flow through
29 fuel variances in hydro communities.

30
31 There are notable similarities in context for NTPC and Yukon Energy, i.e., both are
32 ratebase regulated, and have isolated hydro grids with thermal generation to supply the
33 balance of the power requirement; both have been sensitive to changes in industrial
34 loads; both have dedicated rate stabilization funds to address changes from GRA
35 forecast for hydro generation water availability (variance from LTA) and fossil fuel prices.

² <https://www.ntpc.com/about-ntpc/news-releases/2017/07/07/pub-approves-discontinuation-of-fuel-refund-rider>

1 Notable differences in context are outlined in Attachment 1 [pages 3-5], and include
2 differences in history related to rate equalization across communities; and NTPC
3 changes to consolidate separate stabilization funds pursuant to 2010 policy directions.
4 NTPC also does not currently have a grid system where thermal generation has been
5 impacted by limits on hydro generation under LTA water conditions (i.e., due to mine
6 closures, diesel has not recently been on the margin under LTA water conditions on
7 either NWT hydro grid). As noted, the RSF is subject to a relatively low threshold (+/-
8 \$2.5 million), addresses fuel price as well water variance, and is targeted for a zero
9 balance generally within 12 months after the threshold is hit.

10
11 However, notwithstanding substantial surplus hydro at LTA forecast conditions, a severe
12 drought was experienced in 2014 on the Snare hydro grid that resulted in material diesel
13 generation requirements and costs for the Snare-Yellowknife system. NTPC initially
14 applied for a two-year stabilization fund rate rider to collect a forecast \$20 million added
15 cost resulting from over 60 GWh of additional diesel generation forecast to be needed
16 over two years due to record low water conditions. NTPC subsequently withdrew its
17 application when the territorial government agreed to fund the additional fuel costs. Final
18 GNWT payments of \$37.2 million to NTPC through 2016 for added fuel costs related to
19 low water conditions.³

20 21 **Manitoba**

22
23 Beyond dominant reliance on hydro generation, the context for Manitoba Hydro has few
24 similarities with the context for Yukon Energy.

25
26 Manitoba Hydro is not ratebase regulated and the context for ratemaking requires
27 consideration of long-term financial targets and projections of 10 to as much as 20
28 years. Rate revenues are used as approved by the regulator to build up equity/ retained
29 earnings to fund all of the utility's major risks (including drought). In this sense, Manitoba
30 Hydro uses its retained earnings as a reserve, and does not have a formal rate
31 stabilization fund for water changes impacts or fuel price changes from GRA forecasts.
32 Manitoba Hydro also has extensive connections to several neighbouring jurisdictions,
33 and is able to secure power from these jurisdictions during drought periods and sell
34 surplus power when water supplies are well above long term average hydro generation.

³ 2016 NTPC Annual Report, page 22. Total GNWT payments to offset extreme low water cost impacts for NTPC customers were \$14.2 million in 2014/15 and \$23 million in 2015/16.

1 However, it is noted that drought is a major risk for Manitoba Hydro [similar to Yukon
2 Energy], and rate regulation in Manitoba recognizes the need for the utility to recover
3 drought related cost impacts from ratepayers and notes the related objective of
4 gradualism and sensitivity to customer rate impacts [rather than seeking rapid recovery
5 of added costs or rapid rebate of surpluses]. Consequently, Manitoba Hydro's rate
6 revenue has been approved by its regulator since the early 1990s to build up its equity
7 and reduce its debt to equity ratio (from 90:10 to 75:25) in order that its equity can be
8 sufficient, as a reserve fund, to address drought and other risk events. Specific
9 examples which highlight concerns about drought and adequate equity funds being built
10 up through rates are summarized in YUB-YEC-2-9 - Attachment 1, page 7-8. These
11 examples highlight concerns about drought and adequate equity funds being built up
12 through rates – and demonstrate that regulator concerns about risk as reflected in
13 Orders go beyond only drought related impacts.

14 15 **Newfoundland**

16
17 Newfoundland and Labrador Hydro (NLH) maintains a complex Rate Stabilization Plan
18 (RSP) with separate funds to manage changes from GRA forecasts as regards fuel
19 price; variation in hydraulic generation due to water variability; load variation provisions
20 (i.e., changes in load relative to forecast) affecting each rate class. NLH maintains
21 deferral accounts designed to capture variances in power purchase volumes [including
22 impact of water availability from hydraulic purchases] and fuel efficiencies; and has
23 sought approval of a deferral account to provide for the unforeseen costs incurred with
24 respect to fuel for its standby combustion turbine and diesel generators related to low
25 hydrology.⁴

26
27 Yukon Energy noted in the 2014 rebuttal evidence [provided as YUB-YEC-2-9 -
28 Attachment 1] that “beyond noting that ratepayers bear the risk of hydro variations from
29 forecast water conditions, there is no apparent relevance for the current DCF proceeding
30 of examining further the Orders and filing related to Newfoundland Hydro RSF.”⁵

⁴ For example, see <http://www.pub.nf.ca/applications/NLH2017GRA/rfi/NP-NLH-273.PDF>. and
<http://www.pub.nf.ca/applications/NLH2016StandbyFuel/files/application/Application-ApprovalofaStandbyFuelDeferralAccount-2016-02-05.pdf>

⁵ The evidence notes complexities regarding the RSF related to fund payments/ withdrawals being assigned according to rate class and load variation provisions (i.e., changes in load relative to forecast) affecting each rate class that add a wide range of issues that have no relevance to the DCF or the Yukon context for rate regulation.

1 **British Columbia**

2
3 The context and mechanisms in place in British Columbia were not addressed in the
4 2014 rebuttal evidence [provided as YUB-YEC-2-9 - Attachment 1]. However, the
5 following additional information is provided regarding contingency fund mechanisms in
6 place in B.C. to address water variability risks.

7
8 In 2004, subsequent to an inquiry into BC Hydro's heritage generation assets (which in
9 effect include its existing hydro generation assets), Heritage Special Direction No. HC2
10 was issued by the Province⁶ to establish the Heritage Deferral Account and the Trade
11 Income Deferral Account to capture, respectively, the variances between BC Hydro's
12 actual, and forecast cost of supply from heritage assets, and variances between the
13 actual and forecast net income of Powerex.⁷

14
15 BC Hydro specifically notes as follows regarding its use of variance accounts⁸:

16
17 Variance accounts capture the difference between forecast costs and revenues,
18 on which rates are set in BC Hydro's revenue requirements applications, and the
19 actual costs and revenues that are incurred or received by BC Hydro. Not all
20 forecast costs will be subject to variance account treatment. For those costs that
21 BC Hydro has control over, it generally accepts the financial risk of the difference
22 between the forecasted and actual costs. However, for those costs that BC
23 Hydro does not have control over, it can be difficult to accurately forecast them
24 and therefore regulatory accounts are often set up to capture the difference
25 between the forecast and actual costs and recover or refund the variance,
26 through the rates charged to ratepayers.

27
28 This effectively transfers the forecast cost risk of these uncontrollable costs to
29 customers. BC Hydro considers that it is appropriate that these costs be paid by

⁶ Heritage Special Direction No. HC2 to the BCUC.

http://www.bclaws.ca/civix/document/id/loco92/loco92/158_2005 [accessed on March 21, 2018].

⁷ Powerex was established in 1988 as the wholly-owned electricity marketing subsidiary of BC Hydro – responsible for marketing BC Hydro's surplus electricity in the west.

<http://www2.powerex.com/AboutUs.aspx> [accessed on March 21, 2018].

⁸See pages 12-13 of the BC Hydro's Regulatory Accounts Report at the following link:

<https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/RRRA-2015-2016-regulatory-accounts-report.PDF>

1 ratepayers, as the costs are being incurred in the provision of service to its
2 ratepayers.

3

4 BC Hydro has a Cost of Energy Variance Account which includes Heritage Deferral
5 Account, Non-Heritage Deferral Account and Trade Income Deferral Account.⁹ The
6 stated purpose of the cost of energy variance is to defer the difference between forecast
7 and actual costs of energy and trade income, for recovery in a future period. The
8 following is specifically noted regarding cost impacts related to water variability (i.e.,
9 difference from average water conditions used to set rates) that are ultimately borne by
10 ratepayers:

11

12 ... the Deferral Accounts are used to smooth net income when energy costs are
13 unexpectedly higher or lower than forecast. This may happen due to variations in
14 reservoir water levels (due to more or less precipitation and snow melt in any
15 given year), resulting in the requirement for BC Hydro to change its mix of energy
16 resources to meet load demand. While rates are set assuming average water
17 inflow levels, the lower cost Hydro generation levels can fluctuate by +/- 5,000
18 GWh between low and high water years, resulting in the need to sell surplus
19 power or purchase energy from the market. As water inflow levels are
20 uncontrollable it is appropriate that the risk of this cost should be borne by BC
21 Hydro's customers and recovered in rates.¹⁰

22

23 BC Hydro notes that the balance in HDA increased from \$78 million in F2008 to \$329
24 million in F2009 due to purchases of high cost energy to offset lower than forecast
25 hydro-generation due to low water inflows.¹¹

⁹ The Established by British Columbia Utilities Commission (BCUC) Order No. G-96-04 dated 29th October 2004 at: http://www.bcuc.com/Documents/Proceedings/2004/DOC_5430_BCH%202004RRR%20Final.pdf [accessed on March 21, 2018].

¹⁰ See BC Hydro's Regulatory Accounts Report at the following link:
<https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/RRRA-2015-2016-regulatory-accounts-report.PDF>

¹¹ BC Hydro F2015 to F2016 Revenue Requirements Rate Application, Appendix H, Regulatory Accounts Report, Page 58 of 79. <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/RRRA-2015-2016-regulatory-accounts-report.PDF>

1 **(f)**

2
3 Yukon Energy is not aware of any precedent or principle for using an approach that
4 would mitigate ratepayer risk for water variability through restricting the application of the
5 contingency fund only to variations above or below a certain level of forecast (e.g., 10%).
6 Yukon Energy's understanding of approaches for addressing water variability in other
7 Canadian jurisdictions [see response to part (e) above] also does not support such an
8 approach.

9
10 While such an approach may be technically possible, it would be complex compared to
11 the DCF mechanism currently used. Please also see response to YUB-YEC-2-1(g,h and
12 i).

13
14 **(g)**

15
16 As the Yukon Integrated System (YIS) is highly dependent on hydro generation, there
17 will always be cost risks related to higher than average thermal generation requirements
18 in years when water availability is below average. YEC's investigation of methods to
19 mitigate rate instability risks to ratepayers has, from the outset, focused on contingency
20 fund mechanisms that would be effective in smoothing out the rate impacts of water
21 variations.

22
23 Yukon Energy has reviewed in detail the development of contingency fund mechanisms
24 to address and mitigate impacts of ratepayer cost variability related to water variability
25 [see response to YUB-YEC-2-2(c) and YUB-YEC-2-3(c)]. In summary, Yukon Energy
26 initially provided for a contingency fund out of retained earnings as a means of mitigating
27 ratepayer risks related to water variability, noting at the time that: "Based on the NCPC
28 experience and experiences in other jurisdictions, though, it would be appropriate in the
29 long run for the consumers of the utilities to be paying for their own contingencies." The
30 Low Water Reserve Fund established in the 1991/92 GRA and later Diesel Contingency
31 Fund [established out of the 1996/97 GRA process] were each developed to ensure that
32 impacts of water variability [which were considered ratepayer risk] were managed
33 appropriately in a manner that stabilized rates.

34
35 Yukon Energy has also over this period continued to plan and operate the Yukon
36 Integrated System (YIS) with a focus on ensuring the most efficient use of available
37 water and the ability to use storage on the system. Yukon Energy has continued to look

1 for ways to get the most efficient use of its available assets and to develop lower cost
2 generation resources in order to meet growing demand on the YIS. Integration of the
3 grids and hydro generation enhancements are examples of actions taken in this regard.
4

5 Yukon Energy has also looked at options to reduce its thermal generation fuel costs, and
6 therefore its thermal generation costs as required during low water conditions, including
7 the introduction of LNG as a lower cost fossil fuel source compared to diesel.
8

9 **(h)**

10
11 No, it would **not** be accurate to say that YEC's risk with respect to fuel volumes for
12 thermal generation is mitigated with the DCF or a similar contingency fund.
13

14 As reviewed in response to YUB-YEC-2-1(d), fuel volumes for thermal generation vary
15 primarily due to changes in load or due to water variability. The DCF only addresses
16 variances in fuel requirements related to water variability and specifically does not
17 address such risks related to load variance.
18

19 Fuel price risk is addressed through the Diesel Fuel Price Variance Account and Rider F
20 mechanism and also does not address risk related to load variance.
21

22 Yukon Energy specifically continues to carry the load-related risk for its retail load and
23 for industrial load. Historically, the ERA mechanism was implemented to ensure that
24 when AEY (YECL) loads vary and this variation in load drives changes in the quantities
25 of diesel generation required, AEY (YECL) carries the cost (or captures the savings) that
26 results from these diesel generation changes. Historically, as reviewed in response to
27 YUB-YEC-2-1(d), the ERA had no impact on retail or industrial ratepayers.
28

29 **(i)**

30
31 As noted in response to (h), the statement therein is not accurate. Further, no
32 adjustment to YEC's ROE related to these matters would be appropriate today so long
33 as the current contingency fund mechanisms are retained.
34

35 As reviewed in response to YUB-YEC-2-1(d), YUB-YEC-2-2(c) and YUB-YEC-2-3(c), the
36 regulatory principles that resulted in the development of the DCF (or earlier LWRF),
37 DFPVA and Rider F, and the ERA mechanism included in Rate Schedule 42 have been

1 in place and impacted rate setting since the early 1990's. The ROE for Yukon Energy
2 has been established over this period with consideration of these factors.

3
4 The basis for the Yukon Energy ROE for the 2017/18 test years was reviewed in the
5 following IR responses: YUB-YEC-1-52, YUB-YEC-1-53, YUB-YEC-1-54, YUB-YEC-1-
6 55, YUB-YEC-1-56 and CW-YEC-1-38. Yukon Energy is a small, northern utility (similar
7 to AEY), that carries much higher risks compared to AEY related to generation¹², related
8 to connected industrial load, and related to being the main transmitter and generator on
9 an isolated northern grid¹³. The assessment reflects the current regulatory context,
10 which includes the above noted mechanisms and as such does not need to be adjusted.

11
12 **(i)**

13
14 Were the Board to break with established regulatory precedent in Yukon and for other
15 regulated hydro utilities in Canada and determine that Yukon Energy should bear risks
16 related to water variability, the overall risk profile for the utility would be increased and its
17 ROE would need to be increased accordingly. However, any such measure would not be
18 consistent with Section 3 of OIC 1995/90 that directs the Board to review and approve
19 rates in accordance with principles established in Canada for utilities, including those
20 established by regulatory authorities of the Government of Canada or of a province
21 regulating hydro and non-hydro electric utilities.

22
23 Regardless of the ROE approved, carrying this risk without some deferral account/ rate
24 mitigation mechanism as currently exists would challenge the financial integrity of the
25 utility. Yukon Energy would seek to mitigate the risks related to any such measure by
26 using interim rate applications under conditions when material added thermal generation
27 costs were expected to occur due to low water conditions relative to the last GRA
28 forecast. The ultimate rate instability impacts would still be borne by ratepayers.

¹² With regard to generation risk YUB-YEC-1-55 notes, "The nature of the risk can vary depending on the generation and related cost risks (e.g., fixed costs versus variable costs, new versus very depreciated assets, risks related to renewable energy variability, and risks related to load variation and related cost versus revenue variability), and the relative importance of generation and related costs within the total utility revenue requirement. On all related grounds, YEC's hydro-based generation with new as well as old assets on an isolated grid displays a high level of generation risk."

¹³ YUB-YEC-1-56 notes that "unlike BC utilities, Yukon Energy operates on an isolated grid and cannot purchase power from other electrical systems (or sell surplus power into such systems). This is a critical risk for Yukon Energy that sets it apart from other southern utilities, as well as AEY."



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October 15, 2014

Mr. Bruce McLennan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. McLennan:

**Re: Application to Revise the Diesel Contingency Fund (“DCF”) & Related Amendments to
the Energy Reconciliation Adjustment (“ERA”) – Rebuttal Evidence**

Pursuant to the process and schedule set out in Order 2014-08, please find attached Yukon Energy’s rebuttal evidence regarding the intervenor evidence filed by Utilities Consumers Group on September 3, 2014.

Yours truly,

A handwritten signature in black ink, appearing to read "Ed Mollard".

Ed Mollard CGA
Chief Financial Officer

Re: UCG Evidence filed regarding Yukon Energy Corporation Application (the "Application") to Revise the Diesel Contingency Fund ("DCF") and Related Amendments to the Energy Reconciliation Adjustment

Introduction

On September 3, 2014, the Utilities Consumers' Group (UCG) filed a submission with the Yukon Utilities Board as Intervenor Evidence regarding the above referenced Yukon Energy Application. Yukon Energy as an applicant in this proceeding is submitting rebuttal on this UCG evidence.

In its cover letter, UCG noted that its submission provides "evidence related to rate stabilization mechanisms approved in other jurisdictions which UCG feels should be used to broaden the review of how a mechanism like the proposed Diesel Contingency Fund should be established and used in Yukon." UCG's submission includes a five page summary of mechanisms in Northwest Territories, Manitoba, Newfoundland and Nova Scotia, and over 600 pages of attached Board Orders from the four noted jurisdictions. UCG submits this as "evidence of how other jurisdictions have addressed rate stabilization mechanisms similar to the DCF."

The information and examples from other jurisdictions have been filed on the record of this proceeding by UCG without the necessary context or analysis in order to assist the Board to determine the relevance, if any, of these particular mechanisms to the Yukon integrated system or regulatory environment and the issues related to the DCF in the current proceeding.

In order to assist the Board, the following rebuttal evidence provides context for the other rate stabilization mechanisms included in the UCG submission and assesses the relevance, if any, of these other mechanisms to the current proceeding with specific regard to the DCF. This submission was prepared by Yukon Energy's regulatory consultant (InterGroup Consultants), which (see Attachment 1) has for many years provided expert advice on rate regulation matters to utilities or intervenors in three of the jurisdictions noted (Northwest Territories, Manitoba and Newfoundland).

Yukon Context for DCF and Review of other Rate Stabilization Mechanisms

The DCF, and the predecessor Low Water Reserve Fund (LWRF), were established in Yukon to provide rate stabilization from variability in generation costs from approved GRA forecasts due only to fluctuations in available water flows and wind. In contrast to the fuel price rate stabilization mechanism in Yukon (i.e., Rider F mechanism), comparatively large minimum and maximum caps were established for the DCF to establish a fund large enough to provide rate stabilization in response to varying water flow availability above and below long-term average conditions.

The DCF rate stabilization mechanism was established, and is proposed to continue operating, in the following Yukon context:

1. **Isolated Hydro Grid** - The Yukon grid operated by Yukon Energy is a hydro-based bulk power system with a very small amount of wind generation and with diesel generation to supply the balance of the power requirement. As such, the Yukon grid is isolated with no interconnection to other jurisdictions (no ability to purchase power from others in the event

of drought and no access to additional revenues from sales of surplus power to other jurisdictions).

2. **Load Variability** - The Yukon grid(s) since the late 1980s have experienced a wide range of load conditions that were reflected in the rate stabilization mechanisms adopted and applied from time to time with regard to water availability:
- a. The Mayo Dawson grid had surplus hydro conditions after the UKHM mine closed in the late 1980s until this grid was connected to the WAF grid in mid-2011; under the conditions from the late 1980s until mid-2011, changes in water flow availability on this grid had no impact on diesel generation and no rate stabilization mechanism similar to the DCF was in operation on this grid.
 - b. In contrast, the Whitehorse-Aishihik-Faro (WAF) grid has experienced varying load and hydro generation utilization conditions since the late 1980s:
 - i. When the Faro mine was operating in the 1990s, the WAF grid load was sufficient that changes in hydro generation on the Yukon grid due to changes in water flow availability had a direct, opposite and equal impact on diesel generation – and any change in load from GRA forecasts also was 100% reflected in changes in expected diesel generation under long-term average hydro generation water conditions. The LWRF and then the DCF were established as a dedicated fund on WAF during this period to reflect the regulatory premise that ratepayers bear the risk (cost or benefit) for all water-related hydro generation changes that cause changes in diesel generation relative to the last GRA approved forecast hydro generation - and the LWRF-DCF mechanisms were kept entirely separate from the Rider F rate stabilization mechanism addressing fluctuation in diesel fuel prices from GRA forecasts.
 - ii. When the Faro mine was not operating in the 1990s, and after it was closed in early 1998, the reduced load resulted in surplus hydro generation on the WAF grid under long term average hydro generation water conditions. Accordingly, DCF operation was suspended under these load conditions except when severe drought conditions in 1999 briefly caused a need to operate diesel generation. During these conditions GRA approved rates only included diesel generation costs related to winter peaking and maintenance operation requirements, i.e., rates did not include any diesel generation costs that reflected sensitivity to hydro generation water flow availability.
 - c. By 2012, interconnection of the WAF and Mayo-Dawson grids combined with load growth resulted in conditions where diesel generation costs were once again sensitive to hydro generation water flow availability. Board Order 2013-01 directed that 2012-2013 test year GRA rates reflect 100% of diesel generation forecast to be required on the integrated grid under long-term average hydro generation conditions – and Yukon Energy filed for approval to resume operation of the DCF with

modifications to reflect current integrated grid conditions (including recognition that, unlike the 1990s when the Faro mine was operating, expected diesel generation under long-term average generation would currently account for less than 100% of any changes in grid loads from the GRA forecast).

3. **Rate Policy** - Rate policy requirements in Yukon established by the Public Utilities Act and rate policy OICs such as OIC 1995/90 (and its predecessors) required rate base regulation of Yukon Energy rates as well as equalization of first block retail rates and Major Industrial customer rates throughout Yukon for both public utilities, with specific directions regarding YEC wholesale rates charged to YECL/AEY and provisions to address fuel price changes from approved GRA forecasts.

Other Rate Stabilization Mechanisms - Context and Relevance Assessment

The UCG evidence copies, and purports to summarize, Board Orders dealing with rate stabilization mechanisms in four other jurisdictions (Northwest Territories, Manitoba, Newfoundland and Nova Scotia). The context of each referenced mechanism in each jurisdiction, and its relevance to the current proceeding on Yukon Energy's DCF mechanism, are assessed below.

1. **Northwest Territories (NWT Power Corporation)** – UCG's evidence addresses at length a variety of Board Orders and filings in Northwest Territories since the 1990s regarding rate stabilization mechanisms. However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding.

The context for NWT Power Corporation has notable similarities with the context for Yukon Energy. For example, NWT Power Corporation has two isolated hydro grids, each with diesel generation to supply the balance of the power requirement, and each very sensitive to changes in industrial loads. It also has dedicated rate stabilization funds to address changes from GRA forecast for hydro generation water availability (variance from long term average) and fossil fuel prices, recognizing that the risks for each such change are ultimately born by ratepayers rather than by the utility. Further, NWT Power Corporation has rate base regulation of rates.

The context for NWT Power Corporation also has notable differences from the context for Yukon Energy. For example, the following are noted:

- Until very recently, NWT Power Corporation's rates were set separately for each individual community (e.g., different rates for customers in each community), rather than equalized in the manner established in Yukon in the late 1980s. Some of the Orders and filings referenced by UCG address measures adopted to facilitate a transition to rate zones in the Northwest Territories and do not have any relevance to the DCF mechanism in Yukon.
- NWT Power Corporation has experienced over time various changes to its rate stabilization fund organization, including recent measures to implement a policy directive in 2010 from the Territorial government to consolidate the previously

separate stabilization funds into a single fund (RSF) that addresses a variety of rate stabilization measures (including fuel price stabilization as well as diesel generation stabilization as it is affected by hydro generation variations due to water availability). Beyond addressing specifically how water variability impacts are addressed, the details related to these various changes do not have any relevance to the current proceeding on the DCF mechanism in Yukon. Further, the new consolidated fund and its potential future operation does not offer any information relevant to the current DCF proceeding in Yukon¹.

- Focusing on rate stabilization mechanisms related specifically to water variability impacts on diesel generation, NWT Power Corporation (NTPC) does not currently have any grid system where diesel generation has recently been impacted by limits on hydro generation under long-term average water conditions (i.e., in Yukon terms, diesel has not recently been "on the margin" under long-term average water conditions on either of the two NTPC hydro grids):
 - o The Taltson grid water fund in NTPC is currently inactive due to very low loads on that system relative to available hydro generation - the only relevance to the Yukon DCF is the full recognition by the utility and its regulator that the Taltson water fund may need to be reactivated in future when loads grow to the point where there is potential for diesel generation to be on the margin again under long-term average water conditions. Specific issues between NTPC and Northland utilities on the Taltson grid reflect specific conditions and history for that grid, and have no relevance to current Yukon DCF proceeding.
 - o The Snare-Yellowknife grid loads are also not at a level where diesel is on the margin under long-term average water conditions, e.g., total generation requirements in the most recent test year approximated 200 GW.h/year, and remained below long-term average hydro generation at 220 GW.h/year. Forecast diesel requirements for GRA rates are limited to about 1.2 GW.h/year, and are related only to winter peaking and/or maintenance requirements. Under these conditions, water stabilization funds are only charged when hydro availability falls below 200 GW.h/year due a reasonably significant drought - and there is no upside potential to replenish the fund in years when hydro availability is higher than long-term average (because loads are inadequate to make use of such added hydro generation).

Overall, the evidence confirms that the Snare-Yellowknife grid is the only NTPC grid relevant to the current DCF proceeding, and (to the extent that any relevance is available to the DCF

¹ There is limited operating experience to date in NWT with the new consolidated RSF. Calculation of balances in the water portion of the consolidated fund have not changed from previous rules; however, riders are generally implemented when the consolidated fund reaches a balance of +/- \$2.5 million (no longer any separate triggers for individual portions of the consolidated fund) and riders are calculated to target a zero balance within 18 months (i.e. no longer distinction between targets for fuel and targets for water portions of funds, there is only one target balance for the consolidated fund that includes all components).

proceeding) that experience on this grid is reasonably consistent with Yukon DCF experience and principles during similar periods when diesel was not on the margin on the WAF grid. Further, the water-related rate stabilization mechanisms that would apply on the Yellowknife-Snare grid when diesel is on the margin [which is the case being addressed for the DCF in the current proceeding] are also reasonably consistent with the DCF rate stabilization mechanism under similar conditions (subject to the material differences related to rider operation that were introduced with the new consolidated RSF).

The UCG evidence does not note impacts of the severe drought that was suddenly experienced in 2014 on the Snare-Yellowknife system, resulting in the September 3, 2014 NTPC application for a two-year stabilization fund rate rider to collect a forecast \$20 million added cost resulting from over 60 GW.h of additional diesel generation forecast to be needed over two years due to record low water conditions². Circumstances for this Northwest Territories system and reservoir reflect a variety of NTPC specific conditions and severe drought impacts that remain well below what could occur for Yukon's hydro grid³ - but this recent experience highlights the continued vulnerability of isolated hydro grids to very major diesel cost increases when severe drought conditions occur (as they eventually will), and the continued relevance of water rate stabilization funds such as the DCF to help stabilize rate impact risks for ratepayers.

In summary, the NTPC experience indicates rate stabilization principles related to water variability that fully support the DCF as proposed in the current proceeding. The NTPC mechanisms specifically related solely to water variability are premised on the same principles as the DCF when diesel is on the margin under long term average water conditions, including;

- that ratepayers rather than the utility are at risk for hydro generation availability due to water, and
- that prior to the consolidation of the Snare-Yellowknife fund with NTPC's other stabilization funds as a matter of Territorial government policy, the Snare-Yellowknife water rate stabilization fund provided for fund amounts above or below zero that were well in excess of fuel price related rate stabilization funds and also provided for

² Due to a sudden drought, NTPC went from a balance of zero in the water rate stabilization fund in April 2014 to a balance owing from ratepayers of \$3.4 million at the end of September 2014 with reservoir levels near record lows and recent 2014 inflows below all previous records - and with the expectation that by September 2016 ongoing drought conditions will increase the balance owing from ratepayers to \$20 million. NTPC subsequently withdrew its application when the territorial government agreed to fund the additional \$20 million fuel costs.

³ Based on available water records and 2016 forecast Base Case loads without Alexco (with long-term average diesel generation requirements at 22.9 GW.h/year), diesel generation would exceed 175 GW.h in total over the two worst consecutive water years. [For the most recent such forecast, see Table C-3, Attachment C: Yukon Energy Application for an Energy Project Certificate and an Energy Operation Certificate re; Whitehorse Diesel-Natural Gas Conversion Project; December 2013. An earlier Base Case 2016 forecast filed in November 2012 during the YEC 2012/13 GRA proceeding indicates slightly larger impacts for the two consecutive worst drought years (a copy is provided in current proceeding in YUB-YEC-1-1(b) and (c) Attachment 1).]

any rider to remain in effect only until the fund balance was brought back to its upper or lower range limit, not to a zero balance⁴.

2. **Manitoba (Manitoba Hydro)**– UCG's evidence addresses Board Orders and filings related to Manitoba Hydro over the period 2003 to 2009 that UCG states relate to rate stabilization. However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding.

Beyond dominant reliance on hydro generation, the context for Manitoba Hydro has few similarities with the context for Yukon Energy. Material differences include the following:

- Unlike Yukon, Manitoba Hydro has extensive connections to several neighbouring jurisdictions, including interconnection with the US grid - with resulting ability to secure power from other jurisdictions during periods of drought and to sell surplus hydro generation to other jurisdictions when water supplies are well above long term average and/or domestic loads are inadequate to fully utilize long term average hydro generation.
- Unlike Yukon Energy, Manitoba Hydro has no formal rate stabilization fund(s) for water change impacts or fuel price changes from GRA forecasts - and does not do any formal accounting to track such variances.
- Unlike Yukon Energy, Manitoba Hydro uses rate revenues as approved by its regulator to build up equity/retained earnings to fund all of its major risks (including drought).
- Unlike Yukon Energy, Manitoba Hydro is not rate base regulated - in contrast, under the overall ratemaking context for Manitoba Hydro, ratemaking requires consideration of long-term financial targets and projections of 10 to as much as 20 years⁵.

Notwithstanding all of the relevant differences in context for Manitoba Hydro and Yukon Energy, the following underlying similarities are noted with regard to rate stabilization mechanisms related to water variability:

- Drought is a major risk for both utilities, and planning for drought events is a major consideration for Manitoba Hydro and its rate regulator (the Manitoba Public Utilities Board or "PUB").

⁴ The earlier NTPC water stabilization funds, like the DCF, attempted to provide for fund "caps" i.e., (fund amounts above and below zero at which point a rate rider is to be established) within which the fund may normally absorb swings in water flow availability impacts without needing to introduce any new rate impacts. This approach in each case reflects the expectation that, under a wide range of conditions, when diesel is on the margin under long-term average water conditions impacts on the fund will tend to balance out over time and thereby provide the desired rate stabilization related to water variability impacts.

⁵ For example, PUB Order 25/92 addressed the financial impacts of Limestone Generating Station coming into service. In that application, Manitoba Hydro sought a 3.5% rate increase, which would have yielded a net loss of \$17.3 million for 1992/93, but still permit the achievement of an 85:15 debt: equity ratio by the end of the then relevant Integrated Financial Forecast (IFF) horizon (2002). Hydro indicated the proposal was acceptable as the most important financial forecasts were those looking at the longer-term. Notwithstanding the forecast immediate net loss, the Board's Report had a 2.65% rate increase (also focused on the long-term requirement for reserve).

- Rate regulation for Manitoba Hydro recognizes the ultimate need for the utility to recover drought related cost impacts from ratepayers and notes the related objective of gradualism and sensitivity to customer impacts (as opposed to seeking rapid recovery of added costs from drought, or rapid rebate of surpluses earned under favourable water conditions).
- In order to provide for drought and other major risks, Manitoba Hydro's rate revenue has been approved to build up its equity and reduce its debt to equity ratio (from about 90/10 in the late 1980s to a current target of 75/25) in order that its equity can be sufficient, as a fund, to address drought and other risk events - on the premise that, after such events, rates will be again be increased as required to replenish this equity as needed to achieve the target debt/equity ratio. Over the past decade, the PUB has granted rate increases in excess of Manitoba Hydro requested rate increases in order to build retained earnings and manage risks that the PUB considers the utility may be not adequately considering.
- The following examples are noted to highlight concerns about drought and adequate equity funds being built up through rates - and as well to demonstrate that regulator concerns about risk as reflected in Orders go beyond only drought-related impacts:
 - o PUB Order 7/03 reflected Board concern about the impact of a "five-year drought" being the greatest threat to Manitoba Hydro's financial position, which could cost the Corporation approximately \$1.3 billion at the time through lost export revenues and/or added generation costs (for fossil fuel generation on Manitoba's grid or purchased from other jurisdictions)⁶. The five-year drought reflected a five year period that occurred in the water record (80+ years) where low water flows occurred for five consecutive years (and the repeat of which would constitute the biggest "drought risk" to the Corporation). [In the case of Yukon Energy, a similar multi-year drought risk is demonstrated by water records in the late 1990s - closure of the Faro mine was the sole reason why this drought's impacts on Yukon Energy and ratepayers were muted at that time.⁷]
 - o In the 2004 GRA proceeding for Manitoba Hydro, a severe drought (and consequent reduced power generation and export potential) from 2002-2004 resulted in losses to Manitoba Hydro in excess of \$400 million⁸ – the highest loss ever experienced by Manitoba Hydro at the time. These losses were recovered in their entirety from ratepayers through a series of rate increases as directed by the PUB in Order 101/04⁹ and Order 143/04. The Board in Order 101/04 noted "the drought's impact on the Corporation's retained

⁶ See page 88 of PUB Order 07/2003.

⁷ See YUB-YEC-1-1(b) and (c) Attachment 1).

⁸ PUB Order 101/04 at page 2.

⁹ The Board notes in PUB Order 101/04, "The drought's impact on the Corporation's retained earnings, and a related and increased realization by The Public Utilities Board (the Board) of the financial and operating risks faced by MH, were the primary factors contributing to the Board's decision to grant MH rate increases, as outlined in this Order."

earnings”, and “a related and increased realization [by the PUB] of the financial and operating risks faced by MH¹⁰”, underlined the decision to provide Hydro with a 5% rate increase [effective August 1, 2004 for all customer classes], followed by two conditional rate increases of 2.25% (for each of 2004/05 and 2005/06 upon application of Manitoba Hydro).¹¹

- o At the time of the drought addressed in PUB Order 101/04, Manitoba Hydro had also paid a large dividend to the Province [such dividends had not been typical in prior years]- and losses were pushing back the date of realizing the 75:25 debt:equity ratio target by several years. In this context, discussion and argument addressed options to preserve secure funds to protect ratepayers against major risk impacts - aside from regulatory concern to have adequate “funds” to address such risks, the specifics of this discussion were very much tied to the Manitoba Hydro context and have no useful relevance to the current Yukon Energy DCF proceeding.
- o The Manitoba PUB awarded a 5% rate increase in Order 90/08 when Manitoba Hydro had only requested 2.9% for 2008/09 in Order 90/08, noting that the Board “is focused on the risks that lie ahead and determined to ensure as reasonably as possible that MH has the financial strength to meet the risks”. In this context, the Board was addressing concerns about capital plan cost risks as well as other risks - and the discussion has limited if any useful relevance to the current Yukon Energy DCF proceeding.

In summary, beyond highlighting utility and regulator concern to set aside adequate funds to address drought related risks (which risks ultimately are to be borne by ratepayers), the Manitoba Hydro experience and Orders have no material relevance to the current DCF proceeding.

- 3. Newfoundland (Newfoundland Hydro) -** UCG's evidence addresses Board Orders and filings by Newfoundland Hydro related to 2002/03 and 2013/14, as well as references to earlier history based on these sources, regarding the Rate Stabilization Plan (RSP). However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding.

Newfoundland Hydro's RSP is a complex rate stabilization mechanism with separate funds to manage changes from GRA forecasts as regards fuel price; changes in fuel volumes compared to forecast, i.e., addresses changes in load compared to forecast; water variability; and rural rates¹². In addition to other complexities, fund payments/ withdrawals are assigned according to rate class - and load variation provisions (i.e., changes in load relative to

¹⁰ PUB Order 101/04 at page 2.

¹¹ The Application sought: Approval of electricity rate increases to be effective as of April 1, 2004 and 2005. The proposed rates were projected to result in an annual aggregate revenue increase of approximately \$28 million (3.0%) for the fiscal year April 1, 2004 to March 31, 2005, and an additional revenue increase of \$24 million or 2.5% for the fiscal year April 1, 2005 to March 31, 2006.

¹² Newfoundland and Labrador Hydro Rate Stabilization Plan Report, July 2014, page 1.

forecast) affecting each rate class add a wide range of issues that have no relevance at all to the current DCF proceeding in Yukon.

In summary, beyond noting that ratepayers in each of these jurisdictions bear the risks related to hydro variations from forecast water conditions, there is no apparent relevance for the current DCF proceeding of examining further the Orders and filings related to the Newfoundland Hydro RSF.

- 4. Nova Scotia (Nova Scotia Power)** – UCG's evidence addresses Board Orders and filings related to Nova Scotia Power related to 2011 to 2014 regarding a specific Rate Stabilization Plan that was recently approved for Nova Scotia Power. However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding

Unlike Yukon Energy, Nova Scotia Hydro is not a hydro-based jurisdiction and examples of rate stabilization mechanisms from this jurisdiction are consequently of no apparent relevance for the Yukon context related to the need to provide rate stability in event of material swings in water availability. Accordingly, evidence provided regarding Nova Scotia Power has no apparent relevance to the current Yukon DCF proceeding.

Conclusions

Review of the context for the Orders or filings referenced in four other jurisdictions by the UCG evidence indicates very limited relevance of this information to the current DCF proceeding.

A large portion of the UCG evidence for each jurisdiction references rate stabilization mechanisms other than those related specifically to water variability, (e.g., the Nova Scotia, and most of the Newfoundland and Manitoba references, demonstrate this point as well as the new consolidated RSF for NTPC).

In the cases where fund operation for rate stabilization is actually related specifically to water variability, the evidence shows that mechanisms are context dependent and vary across jurisdictions and over time within jurisdictions in response to specific changes in, and requirements of, the operating environment (e.g. in NWT the Taltson fund has been inactive since the Pine Point mine closure, as there is not enough load on the system to make water availability an issue, and even the Snare-Yellowknife portion of the RSF related to water operates in a context today where diesel is not "on the margin" at long term average water flows).

In conclusion, it can be noted that each of the above noted jurisdictions has adapted specific mechanics for funds or other mechanisms to address water variability where it is a material risk. The specific mechanics vary among the above jurisdictions, and the details of these variations are of limited (if any) relevance to the Board in the current DCF proceeding. What is relevant to the current DCF proceeding, as shown by the above review, is that the following core principles are common to all of the above-noted jurisdictions addressing risks related to water variability:

1. Ratepayers (not the utility or its shareholder) are ultimately at risk for cost impacts caused by variations in water availability.

2. All of the approaches to water stabilization mechanisms recognize that water availability can be self-correcting over time and that some form of fund might help to stabilize rates in this regard if it has sufficiently large "caps".

ATTACHMENT 1 – INTERGROUP EXPERIENCE IN OTHER JURISDICTIONS

InterGroup Consultants Ltd. experience providing expert advice on rate regulation matters to utilities or intervenor groups in Northwest Territories, Manitoba and Newfoundland is as follows:

- **Northwest Territories (Northwest Territories Power Corporation)** – Since 2000, InterGroup has provided support to Northwest Territories Power Corporation (NTPC) with preparing the Corporation's Rate Applications for 2001/03, 2006/08, and 2012/14 fiscal years. InterGroup's responsibilities have included preparation of the Corporation's revenue requirements, cost-of-service and rate design studies. InterGroup also provided rate hearing support including expert witness testimony before the Northwest Territories Public Utilities Board.
- **Manitoba (Manitoba Industrial Power Users Group)** – InterGroup has provided ongoing advice to the Manitoba Industrial Power Users Group (MIPUG) in their role as intervenors in each of the Public Utilities Board's reviews of electricity rates since December 1988 when the Board was first given the jurisdiction to approve electricity rates. MIPUG played a role in the Board's review of Manitoba Hydro's Major Capital Projects in 1990, the Centra Gas acquisition in 1999, and Manitoba Hydro's Needs for and Alternatives To capital projects hearing in 2014. InterGroup assists MIPUG in electricity rate design matters with Manitoba Hydro, and has provided rate hearing support including expert witness testimony before the Manitoba Public Utilities Board in each of the above referenced proceedings.
- **Newfoundland (Island Industrial Customers)** – Since 2001, InterGroup has provided rate hearing support to the Island Industrial Customers including expert witness testimony before the Newfoundland and Labrador Board of Commissioners of Public Utilities on areas such as revenue requirement, rate design and long-term system planning. InterGroup has assisted the Island Industrial Customers with ongoing rate design matters including the Rate Stabilization Plan.

1 **TOPIC:** Final Utility Costs for Fiscal Year

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-8, PDF page 36
4 Figure 2-1

5
6 **PREAMBLE:**

7
8 Figure 2-1 shows a model for final utility costs.

9
10 **QUESTION:**

11
12 a) In Figure 2-1, the third box states: 1. YEC final expected fuel costs for actual load
13 (excluding water variance). Is it possible for YEC to develop a model whereby fuel
14 costs are based on actual volumes of diesel consumed, and the accounting for
15 variations in water are accounted for separately? Please explain.

16
17 **ANSWER:**

18
19 **(a)**

20
21 The referenced third box in Figure 2-1 addresses final utility costs for a fiscal year after
22 the second box contingency fund (DCF or equivalent) annual filing ensures that YEC's
23 final fuel costs remove any variances related to water variability, i.e., ratepayers (through
24 the contingency fund mechanism) bear the cost risk related to water variability from the
25 GRA forecast. Figure 2-1 shows how this outcome needs to occur under both ST and LTA
26 GRA forecast alternatives, and assumes that absent the DCF a similar contingency fund
27 mechanism would be required.

28
29 On the matter of developing a model whereby fuel costs are based on actual volumes of
30 diesel (and LNG) consumed and the accounting for water variations are accounted for
31 separately, the DCF mechanism already in effect does this with regard to LTA GRA
32 forecasts. The year-end DCF determinations in effect account for actual thermal
33 generation volumes of diesel and LNG, and account for water variations from GRA LTA
34 forecast separately (with related YEC payments into the DCF, or rebates from the DCF,
35 as required). Also, please see response to YUB-YEC-2-1(d) and (i) as well as YUB-YEC-
36 2-2(c), for review of the need to ensure that water variation impacts are separately
37 accounted for regardless as to whether LTA or ST GRA forecasts are adopted.

1 **TOPIC: LTA versus ST GRA Forecast Alternatives**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-11, PDF page 39

4
5 **QUOTE:** As expected during a period of favourable water conditions, the ST
6 Alternative GRA Forecast would reduce the test year revenue
7 requirements (by \$2.0 and \$0.7 million) and cumulative rate increase
8 required by 2018 (reduced by about 11%, from 9.08% to 8.11%).
9

10 **PREAMBLE:**

11
12 **QUESTION:**

13
14 a) Please confirm that favorable water conditions refer to water conditions better
15 than the LTA forecast.

16
17 b) Please provide the derivation of the \$2.0 and \$0.7 million reductions and any
18 assumptions made in that derivation.

19
20 c) Please provide further explanation as to how the DCF cap results in
21 Rider E rebates that reduce actual ratepayer final bills. Please provide a
22 numerical example.
23

24 d) Please explain “major differences in ratepayer bill impacts with ST versus LTA
25 forecast alternatives for the current GRA for 2017-18 are likely to be limited if the
26 current DCF cap is retained”.
27

28 **ANSWER:**

29
30 **(a)**

31
32 Confirmed.
33

34 **(b)**

35
36 Please see Table 1 below for the requested information.

Table 1: Change in Revenue Requirements for 2017 and 2018 Test Years

2017 Revenue Requirement (\$000)		Original Filing	ST Alternative	Change	Note
1	Expected thermal generation (GW.h) (Table 2.2)	14.1	1.1	(13.0)	Change from LTA to ST forecast
2	LNG	12.7	0.7		
3	Diesel	1.4	0.5		
4	Thermal Generation Cost	\$2,240	\$218		
5	Maintenance Thermal	446	446		
6	Maintenance Thermal Cost	\$102	\$102		
7	Power Purchase Cost	\$39	\$39		
8=4+6+7	Total Fuel and Purchased Power Costs (Table 3.2)	\$2,381	\$360	-\$2,022	Change from LTA to ST forecast; 60% LNG and 40% diesel
9	Non-Fuel Operating and Maintenance (Table 3.1)	\$22,060	\$22,060	\$0	
10	Depreciation and Amortization (Table 3.14)	\$10,814	\$10,814	\$0	
11	Return on Rate Base (Table 3.1)	\$13,289	\$13,283	-\$6	Change in working capital.
13=8+9+10+11	Revenue Requirement	\$48,544	\$46,516	-\$2,028	

2018 Revenue Requirement (\$000)		Original Filing	ST Alternative	Change	Note
1	Expected thermal generation (GW.h) (Table 2.2)	14.5	8.2	(6.3)	Change from LTA to ST forecast
2	LNG	13.0	4.9		
3	Diesel	1.4	3.3		
4	Thermal Generation Cost	\$2,293	\$1,590		
5	Maintenance Thermal	329	329		
6	Maintenance Thermal Cost	\$75	\$75		
7	Power Purchase Cost	\$39	\$39		
8=4+6+7	Total Fuel and Purchased Power Costs (Table 3.2)	\$ 2,407	\$ 1,705	-\$ 702	Change from LTA to ST forecast; 60% LNG and 40% diesel
9	Non-Fuel Operating and Maintenance (Table 3.1)	\$ 22,016	\$ 22,016	\$ -	
10	Depreciation and Amortization (Table 3.14)	\$ 11,094	\$ 11,094	\$ -	
11	Return on Rate Base (Table 3.1)	\$ 14,348	\$ 14,345	-\$ 2	Change in working capital.
13=8+9+10+11	Revenue Requirement	\$ 49,864	\$ 49,160	-\$ 705	

(c)

The comments at page 2-11 of the ERA Part 2 Application notes that the DCF cap can result in Rider E rebates to the ratepayer bills under favourable water conditions that reduce actual final bills applicable to ratepayers under the LTA forecast approach.

For example, in its Order 2015-06, the Board directed that YEC refund DCF contributions in excess of the \$8.0 million cap through a rate rider applicable to all firm sales throughout the Yukon (Rider E), which was at -0.68 cents/kWh, effective September 1, 2015. When the cap applies in this situation, the rebate in effect returns to ratepayers any added amounts paid into the DCF by YEC. Accordingly, in a year when the cap applied as of January 1st, subsequent payments that YEC makes into the fund (to address the gap between LTA and actual thermal generation in that year) thereby get rebated after year end to ratepayers, and in effect remove (with the delays inherent in the process) the added charge to ratepayers related to LTA versus actual thermal generation.

1 Appendix 3.5 in the 2017/18 GRA provides the 2016 DCF Annual Report. During 2016 the
2 following conditions existed:

- 3
- 4 • The DCF cap was in force from the outset of the year.
- 5
- 6 • Rider E rebates over the year at \$0.68 cents per kW.h rebated \$2.464 million to
7 ratepayers.
- 8
- 9 • Total YEC payments into the DCF for 2016 (reflecting the gap between LTA and
10 actual thermal generation) were \$0.990 million.
- 11
- 12 • Accordingly, the impact of the DCF rebates in 2016 (in rebating amounts to
13 ratepayers as required due to the \$8 million DCF cap) was much higher than the
14 added cost required for LTA versus actual thermal generation in that year.
- 15
- 16 • The end result was that ratepayer bills in 2016 were actually well below the LTA-
17 based rate charges as approved in the 2012/13 GRA, and also lower than rates
18 that would have been needed to recover actual thermal generation costs in 2016.
- 19

20 Appendix 4.2 in the 2017/18 GRA provides residential and general service bill impact
21 tables (Tables 4.2A-3 and 4.2A-4) that show the impact of the \$0.68 cent/kW.h Rider E on
22 bills in 2016, and in 2017 and 2018 under the GRA forecast rates.

- 23
- 24 • For an average consumption of 1,000 kW.h/month Rider E reduces residential bills
25 by about \$6.8/month before tax or \$7.14/month after tax.
- 26
- 27 • For an average consumption of 2,000 kW.h/month Rider E reduces general service
28 bills by about \$13.6/month before tax or \$14.3/month after tax.
- 29

30 **(d)**

31

32 The response above to (c) reviews how the DCF cap can reduce actual ratepayer bill
33 impacts with the LTA hydro generation GRA forecasts, and provides an example for actual
34 outcomes in 2016 when ratepayers bills were reduced well below LTA thermal generation
35 costs as a result of Rider E rebates of \$2.464 million related to the current DCF cap.

1 The ST Alternative GRA Forecast as compared with the LTA GRA Forecast as filed shows
2 reductions in test year revenue requirements of \$2.0 million in 2017 and \$0.7 million in
3 2018, reflecting forecast hydro conditions in these years that exceed LTA forecasts. This
4 assessment, however, does not consider the impact of Rider E rebates related to the DCF
5 cap. As demonstrated by actual 2016 conditions, Rider E rebates can reduce and, under
6 some conditions, more than offset the difference in ratepayer impacts between LTA and
7 ST GRA forecasts.

8
9 If it is assumed that actual hydro conditions in each test year occurred as per the ST
10 forecast, then the ultimate difference between the ST and LTA GRAs as at the end of each
11 year would be reflected in DCF (or equivalent contingency fund) requirements, i.e., under
12 the LTA GRA forecast YEC would be required to pay into the DCF an amount equal to the
13 gap between LTA and ST thermal generation costs, while under the ST GRA forecast YEC
14 would not need to make any such payment into the DCF. The following observations are
15 provided based on this hypothetical example:

- 16
17 • Overall, the ST GRA forecast will tend to result in materially reduced payments
18 into the DCF under favourable water conditions.
19
- 20 • Under the above example, the LTA GRA forecast would require a YEC payment
21 into the DCF at the end of 2017 that would in effect equal the revenue requirement
22 reduction under the ST versus LTA GRA forecasts.
23
- 24 • However, if the DCF cap is exceeded at the end of 2017 under the LTA GRA
25 forecast by the amount of this new YEC payment, then Rider E would be assumed
26 to rebate to ratepayers the full amount of this new YEC payment over the following
27 year (2018) - and the major differences in ultimate ratepayer bill impacts with ST
28 versus LTA forecast alternatives for the current GRA over 2017 and 2018
29 combined would likely be reduced.

1 **TOPIC: ST Versus LTA Hydro Generation Forecasts**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-12, PDF page 40

4
5 **QUOTE:** Adoption of the ST alternative today would expose ratepayers to
6 considerable rate instability risks.

7
8 **PREAMBLE:**

9
10 **QUESTION:**

11
12 a) When would the asserted rate instability arise? Please explain.

13
14 b) The second bullet under consistency with past Board decisions indicates that
15 current rates are well above what they would be if ST hydro forecasts were being
16 utilized. If the Board directed YEC to adopt ST hydro forecasts for the test period,
17 everything else being equal, would rates be reduced? Please confirm that once
18 the rates were set there would be no instability during the test period. If not
19 confirmed, please explain.

20
21 **ANSWER:**

22
23 **(a)**

24
25 The referenced general statement addressed the added rate instability risks for Yukon's
26 Integrated System (and thus all Yukon ratepayers) that is inherent in adopting ST GRA
27 forecasts for hydro generation versus LTA GRA forecasts for hydro generation.

28
29 Beyond initial rate instability created by changing GRA rate determinations from LTA to
30 ST forecasts, the timing for this rate instability will depend on the timing for loads and
31 water variances. For example, a drought event in any year would necessitate a sharp
32 increase in rates in that year.

33
34 Please see response to YUB-YEC-2-2(c) and YUB-YEC-2-3(c) for review of past Board
35 consideration of ST hydro forecasts versus LTA hydro forecasts, and the reasons that lead
36 to suggesting and then adopting LTA hydro forecasts.

1 **(b)**

2
3 The ST Alternative GRA Forecast indicates that adopting ST hydro forecasts for the 2017-
4 18 test period, everything else being equal, would reduce required rates to be set for the
5 test period pursuant to this GRA. The result would introduce the type of rate instability for
6 future years that the Board expressed concern about in Order 1992-1 (when better-than-
7 LTA water conditions facilitated a short-term rate reduction prior to adoption of LTA for
8 GRA purposes - see response to YUB-YEC-2-2(c) for more detailed review).
9

10 In short, the rate instability issue associated with the ST forecast alternative is not focused
11 on the 2017-18 test years. The rate instability issue relates to long-term rates relevant to
12 the long-term hydro generation assets, and the appropriate price signals and charges
13 relevant for overall system energy supplied with these assets (where variability in annual
14 water availability causes variability in annual hydro generation, which results in thermal
15 generation annual cost variances). The LTA approach for rate setting also reflects the
16 business case approach adopted for evaluation of new renewable hydro energy
17 generation options.
18

19 As noted in response to YUB-YEC-2-11(c and d), overall bill impacts (versus impacts only
20 from rates approved in the GRA) on customers during and after the test period will be
21 impacted by Rider E rebates and ongoing DCF implementation. Rider E changes could
22 offset or magnify changes related to the shift from LTA to ST hydro forecasts.
23

24 Given that final test year rate approvals in this instance will only occur at best soon before
25 the end of 2018, the only rate instability during the test period will now be that related to
26 setting interim versus final rates related to this GRA.
27

28 Looking beyond the current GRA, and assuming that thermal generation fuel costs
29 changes related to water variance continue to be borne by ratepayers, rate changes will
30 likely be required by YEC as soon as low water conditions appear to be emerging. In future
31 GRAs, changes of this type could occur during the test period, either before or after rates
32 are set.
33

34 The GRA provides evidence on the potential fuel cost instability (and therefore rate
35 instability) under a ST alternative that varies rates with annual variance in thermal
36 generation variances related to water conditions. Appendix 3.4, Attachment 3.4.4 reviews
37 thermal generation fuel cost impacts associated with water variability at different grid

loads, using the GRA forecast fuel prices and thermal unit efficiencies. Assuming the 90/10 LNG/diesel mix proposed in the GRA, the following cost range impacts can be noted over the range of the 35 water years of record used for the GRA:

- At 420 GW.h approximate GRA load forecast for 2018 (Table 3.4-6A):
 - o Annual required thermal generation ranges from 0.24 GW.h (multiple water years) to 107.5 GW.h (1999 water year); in 10 of the 35 water years thermal generation exceeds the LTA of 13.8 GW.h/year.
 - o Annual thermal fuel cost (2017\$) variance due to water ranges as follows under ST alternative:
 - \$2.20 million at LTA thermal generation
 - \$0.04 million at lowest thermal generation (highest water years)
 - \$17.02 million at highest thermal generation (lowest water year)
 - In summary, there is a gap of \$16.98 million/year in fuel costs between the highest and lowest water years; based on 2018 GRA forecast consolidated revenues at existing rates of \$72.5 million (Table 4.2 in the GRA), the rate impact variance over this range of fuel costs approximates an average rate impact of 23% for all firm electricity sales in Yukon.
- At 490 GW.h approximate 2018 load with VGC Group load added:¹
 - o Annual required thermal generation ranges from 5.77 GW.h (1992 water year) to 125.51 GW.h (1999 water year); in 16 of the 35 water years thermal generation exceeds the LTA of 51.1 GW.h/year.
 - o Annual thermal fuel cost (2017\$) variance due to water ranges as follows under ST alternative:
 - \$8.08 million at LTA thermal generation
 - \$0.91million at lowest thermal generation (highest water years)
 - \$19.87 million at highest thermal generation (lowest water year)

Issues and impacts related to contingency funds, LNG allocations for ST versus LTA forecasts, and other related issues that arise with ST versus LTA hydro forecasts remain to be addressed in the event that the Board directed YEC to adopt ST hydro forecasts for the test period. Resolution of these issues may change the estimated impacts provided in the ST Alternative GRA Forecast.

¹ See John Maissan-YEC-1-21-Revised, Table 3.4-8A.

1 **TOPIC:** **ST versus LTA Hydro Generation Forecasts**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-12, PDF page 40

4
5 **QUOTE:** The LTA forecast alternative, in combination with the DCF, adjusts to
6 changes in water conditions without the need for new GRAs to adjust
7 rates in response to changes in water conditions; in contrast, the ST
8 forecast alternative presumes that a new GRA is likely to be needed as
9 soon as water condition deterioration is forecast even relative to current
10 favourable water conditions.

11
12 **PREAMBLE:**

13
14 **QUESTION:**

- 15
16 a) Would a GRA proceeding due to unfavorable water conditions be seen as a
17 positive if it sends correct pricing signals to ratepayers to modify their
18 consumption? Please explain.

19
20 **ANSWER:**

21
22 **(a)**

23
24 No. Short-term pricing to reflect changing water conditions would not provide appropriate
25 price signals relevant to YIS energy supplied with long-term hydro generation assets
26 (where variability in annual water availability causes variability in annual hydro generation,
27 which results in thermal generation annual cost variances). The ST approach for rate
28 setting would also not reflect the business case approach adopted for evaluation of new
29 renewable hydro energy generation options, i.e., project evaluation could otherwise
30 become very sensitive to ST hydro generation water condition forecasts.

31
32 For the reasons described below, it would not be fair or appropriate to replace the DCF
33 and the LTA forecast alternative with rate instability, through the use of GRA or other
34 proceedings, to send price signals to ratepayers in order to modify consumption in
35 response to high versus low water conditions. See response to YUB-YEC-2-12(b) for
36 review of potential annual thermal fuel generation cost variance due to water variance at
37 different loads.

1 Further, the question ignores the current reality that existing DCF cap levels necessitate,
2 even with the current DCF, material added Rider E charges during extreme low water
3 conditions and also result in material Rider E rebates under current favourable water
4 conditions.¹ Under extended drought conditions and the current DCF cap, higher rates will
5 in any event be needed for several years – without introducing ongoing rate variances that
6 seek to track ST water variances.

7
8 The following are noted regarding why the approach of shifting rates to reflect varying
9 water conditions would not fit with the long standing, accepted regulatory context in Yukon
10 since the late 1980's (see also response to YUB-YEC-2-2(c) and YUB-YEC-2-3(c) for a
11 review of GRA filings and Board Orders during this periods on the matter of rate
12 stabilization through adoption of contingency funds and LTA forecasts).

- 13
14 • Rate design criteria are inherently competing, most notably “economic and price
15 signals” (i.e., economic efficiency) versus “rate stability and predictability”.
- 16
17 • From the outset of YEC's rates being regulated by the Board, it has been accepted
18 as a basic principle that diesel cost variances from forecast due to water availability
19 variances are a ratepayer risk and not a utility risk. Similar to other hydro-based
20 systems, the system in place in Yukon to deal with water flow variation since the
21 1990's has been intended to maximize rate stability and predictability and mute the
22 harsh short-term economic efficiency criteria (to the extent it might be relevant) as
23 it arises with respect to diesel cost changes related only to water availability
24 variances from approved forecasts used to set rates.
- 25
26 • The DCF [and earlier LWRF] were established specifically to smooth out short term
27 price variability related to water availability and to provide firm rate customers with
28 stable and appropriate longer term price signals.
- 29
30 • If economic efficiency criteria principles had been favoured principles in relation to
31 addressing water flow variation, a DCF (or similar mechanism) would not have
32 been adopted to stabilize rates and rates would have varied based on short term

¹ See 2017-18 GRA, Table 3.4-5 and 3.4-6A, Appendix 3.4 (Attachment 3.4.4). Current Rider E rebates with the +/- \$8 million DCF cap are \$0.68 cents/kW.h. Under drought conditions with the current DCF cap and 2018 GRA forecasts, an added Rider E charge (above LTA rates) averaging \$4.18 million per year would be needed for 7 consecutive years. Increasing the DCF debt cap to \$16 million would reduce the added Rider E charge during drought to an average of \$2.2 million per year over 6 consecutive years.

1 water conditions at the time of each GRA. For example, when water conditions
2 were above average, rates would have been relatively low, and in the case of low
3 water, or drought conditions, there would have been harsh (and likely impractical)
4 rate increases or special riders required to recover higher diesel costs. In short,
5 the very concept of including long-term average water and a DCF in the rate
6 system (as approved in Board Order 2013-01 as well as in the 1996/97 GRA in
7 response to the joint submission of YEC and YECL) is intended to increase the
8 rate stability of the system and decrease the harshness of the short-term economic
9 efficiency outcome.

10
11 If an alternative approach was to be considered, providing price signals related to water
12 availability would create many new concerns.

13
14 For example, it is not realistic to assume that the "cost of a severe drought" could ever be
15 borne by only those ratepayers using power at the time of the drought. The worst year
16 drought condition is currently expected (with 2018 test period forecast load and fuel prices)
17 to require more than 100 GW.h of thermal generation with single year added fuel costs (at
18 GRA forecast fuel prices and fuel mix, and 420 GW.h annual grid load) approximating
19 \$14.8 million over and above the LTA fuel cost of \$2.2 million/yr - and with prospects for
20 extended severe low water conditions (i.e., thermal generation equal or exceeding 24
21 GW.h/yr when LTA thermal requirement is only 13.9 GW.h/yr) to occur over eight of nine
22 consecutive years². Such conditions would create several practical issues for any attempt
23 to set prices based on actual annual diesel fuel costs, including:

- 24
25 • The difficulty of preparing, reviewing and approving in a timely way (i.e., to be
26 operative in each year of the drought) the necessary GRA submissions needed to
27 approve the needed rate changes.
28
29 • Aside from time needed for regulatory processes, assessment of actual water
30 conditions affecting any given year can be subject to its own issues, i.e., forecasts
31 for a subsequent year are subject to material change up to the end of the previous
32 summer, and actual water conditions during any given year can also obviously
33 change water conditions for that year.

² See 2017-18 GRA, Table 3.4-6A, Appendix 3.4 (Attachment 3.4.4).

- In addition to the above issues, imposing such added drought costs in rates for the affected year (or even spread over "a few" years) would result in "rate shock" for all Yukon ratepayers. In practice, one way or the other, drought-related cost impacts would need to be charged to ratepayers over many years, i.e., including many years beyond when the actual drought water conditions occurred.

Looking beyond issues related to trying to charge drought costs only during drought conditions, providing price signals related to water availability would also create issues for a range of consumer and utility investments and tend to frustrate rather than enhance effective long-term planning by ratepayers and the utility. Basic examples of such issues would include:

- In high water years (i.e., over half of the 35 water years at 420 GW.h/yr load), ratepayers would be given lower prices for power, suggesting that (to the extent feasible) ratepayers should increase power use through investment in electric heating, minimizing of DSM, developing new business activities, etc.; high water years would mask the inevitable increases needed under low water conditions, as well as any rate impacts related to major increases in fuel prices, increased need for thermal generation at LTA conditions associated with higher loads, and the benefit of investing in new renewable resources to displace fossil fuels.
- In low water years (i.e., about 20% of the 35 water years at 420 GW.h/yr load), ratepayers would be given much higher prices for power, suggesting that (to the extent feasible) ratepayers should reduce power use through switching to other heat sources, maximizing DSM, cutting back on new business activities, etc.; low water years would send price signals of long-term power costs well above the likely long term requirement, inhibiting business and consumer confidence in Yukon's ability to provide affordable and competitive power costs, and encouraging longer-term renewable resource investment based on ST fossil fuel cost savings.
- Overall, it is easy to see a wide range of ratepayer issues related to ST pricing based on water variance impacts on thermal generation, and difficult to forecast long term benefits in securing more efficient overall use of electricity.

In summary, the DCF allows the Board to set rates that display rather than mask the expected long-term cost of thermal generation based on current thermal fuel prices, grid renewable generation capability, and forecast grid loads. The ability to provide such price

1 signals is particularly timely and important today when LTA thermal generation
2 requirements are notably growing (due to thermal generation once again being relevant
3 for supply of GRA forecast loads, and with growth in grid loads with the upcoming Victoria
4 Gold mine connection) at a time when high water conditions would otherwise mask the
5 underlying change that is taking place.

1 **TOPIC: Risks**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-13, PDF page 41

4
5 **QUOTE:** Specific risks are related to this ST forecast for reasons not related
6 to water conditions, e.g., experience from 2012-2016 has shown
7 actual annual thermal generation averaging 2.45 GW.h/year, or
8 well above the ST forecast of approximately 1.1 GW.h in 2017 of
9 the current GRA

10
11 **PREAMBLE:**

12
13 **QUESTION:**

- 14
15 a) Please describe the various specific risks referred to in the quote.
16
17 b) If the DCF is a contingency fund based on variations in water levels, how does
18 LTA address the specific risks identified in part (a)?
19
20 c) Is the DCF used for more than variations in water levels? If so, please explain
21 all events that LTA and the DCF address.
22

23 **ANSWER:**

24
25 **(a)**

26
27 The referenced quotation indicates that recent experience documents risks that actual
28 thermal generation requirements will be well above ST forecast amounts for reasons not
29 apparently related to the ST model assessment of water conditions. The specific reasons
30 for this variance have not been examined.

31
32 The specific example of experience from 2012-2016, as reviewed in more detail at page
33 A2.2-2, has shown actual annual thermal generation averaging 2.45 GW.h/year (net of
34 capital and RFID thermal), or 22% of LTA thermal generation over these five years and
35 well above the ST forecast of approximately 1.1 GW.h in 2017 in the current GRA. The
36 thermal generation during 2012 to 2016 ranged from 0.6 GW.h in 2014 (LTA thermal was

1 5.3 GW.h) to 5.1 GW.h in 2016 (LTA thermal was 10.5 GW.h).¹ The experience over this
2 period, when there was higher than LTA water and hydro generation, highlights thermal
3 generation levels average above what ST forecasts would suggest.

4
5 As reviewed in response to CW-YEC-2-1 (Table 2), actual 2017 thermal generation
6 (excluding capital, RFID and maintenance) was 13.261 GW.h, well above the ST forecast
7 in the GRA of 1.1 GW.h for all of 2017, with diesel at 3.623 GW.h and LNG at 9.638 GW.h.²
8 The added thermal generation in 2017 was focused in the five winter months (November
9 January-March, November-December), suggesting ST model limitations in assessing
10 potential thermal requirements during peak winter months when there is higher than
11 average available water.

12
13 In short, based on this recent experience, thermal generation required for system
14 operation has often been well in excess of the current ST forecasts under conditions when
15 there is higher than average available water. Based on this, adoption of the ST hydro
16 forecast for GRA purposes would have to deal with this issue.

17
18 **(b) and (c)**

19
20 The specific risks identified in part (a) related to use of current ST forecasts, particularly
21 for 2017. Based on the ST forecasts related to expected water availability, actual thermal
22 generation in the first half of 2017 was well above what was expected. YEC has not to
23 date identified why this was the case, or how the ST forecast and the LTA forecasts may
24 be reasonably compared in this context. In short, it is unclear what, if any, issues this
25 experience indicates with regard to risks relevant to the LTA hydro forecast.

26
27 As outlined in the DCF Term Sheet, the purpose and function of the DCF is to smooth
28 customer rate changes from thermal generation cost impacts caused by fluctuation of
29 hydro generation due to water conditions or changes in wind conditions [i.e., it addresses
30 variability related to both water and wind]. The fund is intended to be used only to address
31 thermal generation fuel cost changes due to variations from LTA water and wind
32 availability.

¹ See GRA, Appendix 3.5, DCF 2016 Annual Report, Table 2.

² As reviewed at page A2.2-2 in the ERA Application Part 2, actual thermal generation in the first six months of 2017 was well above the ST forecast in the GRA for all of 2017.

1 The proposed DCF mechanism isolates thermal generation cost variances from LTA due
2 to water and wind availability.

3
4 The DCF excludes any specific non-water-related thermal generation operation risks that
5 are confirmed to be material and able to be isolated, e.g., risks related to RFID events,
6 capital projects, thermal unit fuel efficiencies, and (as proposed for the first time in the
7 current Application) thermal generation maintenance and run-up requirements. Payments
8 that go into or out of the DCF after year-end reflect the difference between LTA thermal
9 generation and actual thermal generation after removal of the specific non-water-related
10 thermal generation amounts that have been identified and isolated to date. YEC bears the
11 risk and costs for the actual thermal generation amounts that are removed from the DCF
12 year-end determinations (other than RFID related costs).

13
14 YEC is not aware of any consistent and reasonable way to isolate operation risks related
15 to use of water for hydro generation to the extent that these may impact thermal generation
16 costs. Such isolation has not been attempted in either the LWRF or the DCF. Further, as
17 noted in the response to YUB-YEC-1-6(b) (ERA Part 1 Application), YEC has well
18 established systems to monitor its use of available water, and is not aware of any material
19 impacts on the effectiveness of LWRF or DCF determinations related to the water
20 management element of its systems operation.

21
22 Overall, Yukon Energy believes that the proposed DCF continues to fulfill its purpose,
23 subject to the limitations related to the DCF cap as discussed in Section 1.4 of Appendix
24 3.4 of the GRA Application.

25
26 Please also see response to AEY-YEC-2-1.

1 **TOPIC: Short-term Alternative GRA Forecast**

2
3 **REFERENCE:** YEC ERA Application, page 2-13, PDF page 41

4
5 **QUOTE:** On pdf page 41 of the application, YEC
6 states:

7
8 Considerable separate risk is related to water conditions, i.e., there
9 is the potential material risk that water conditions will deteriorate,
10 and very little possibility that water conditions could be better than
11 assumed in the ST forecast for the 2017-18 GRA.

12
13 **PREAMBLE:**

14
15 **QUESTION:**

- 16
17 a) Please explain how YEC concluded that there is “very little possibility that
18 water conditions could be better than assumed in the ST forecast...”
19
20 b) Notwithstanding the answer to (a) above, in the context of a two-year period,
21 is it possible that the second year could have better water conditions than
22 the first year?

23
24 **ANSWER:**

25
26 **(a) and (b)**

27
28 The referenced statement related primarily to the 2017 test year where reservoir levels
29 at the outset were reasonably full. At the forecast 2017 grid loads there is little
30 likelihood that actual hydro generation related to water conditions would be higher than
31 the ST forecast.

32
33 In the context of a two-year period, however, the ST forecast for the second year (2018)
34 relies on forecast reservoir levels after the first year. For this reason, the ST forecasts for
35 the second year hydro generation related to water conditions are lower than for the first
36 year. Accordingly, it is very possible that actual hydro generation related to water
37 conditions in 2018 could be better than assumed in the ST forecast for 2018.

1 The following are specifically noted regarding the limitations of a ST hydro forecast and
2 the forecast included in Appendix 2.2 of the Two Part ERA Application:

- 3
4 • Experience with the Yukon grid, as well as many other hydro grids, shows that
5 recent history (e.g., the latest 5-year average for reservoir levels) provides no
6 reliable guidance as to what to expect beyond about 18 months from a current
7 situation, i.e., a switch from abundant water conditions to low water conditions in
8 particular is not revealed by such an approach.
9
- 10 • ST forecasts that would be used to forecast GRA thermal requirements simply
11 extend current known reservoir levels using LTA water inflows and forecast grid
12 firm loads without any resets during the forecast period based on any recent
13 5-year averages for reservoir levels.
14
- 15 • As reviewed in footnote 13 of the filing, the 5-year average in this instance
16 reflected a period with water flow conditions higher than LTA. Accordingly, a ST
17 forecast using the 5-year average reset in this instance increases hydro
18 generation in year 2 compared to the approach adopted of extending the ST
19 forecast without any such reset. The result is considered to reduce forecast risks
20 related to the second year.

21
22 Please also see response to YUB-YEC-2-18(c).

1 **TOPIC: Risks**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), page 2-13, PDF page 41

4
5 **QUOTE:** A ST alternative thermal cost or contingency fund account mechanism
6 would need to specify how changes in actual thermal generation from
7 GRA forecasts can be separated into water-related changes versus
8 changes due to load adjustments, forecast errors or other factors.

9
10 **PREAMBLE:**

11
12 **QUESTION:**

- 13
14 a) Under the current LTA approach, how are changes due to load adjustments,
15 forecast errors and other factors accounted for? Please explain.
16
17 b) Should any of these factors (load adjustments, forecast errors and other
18 factors) be part of the overall forecast risk of YEC? Please explain.

19
20 **ANSWER:**

21
22 **(a)**

23
24 DCF determinations as proposed in the GRA take into account actual diesel or LNG use
25 in the year net of capital, RFID generation and maintenance run-ups of thermal units, as
26 well as the effects of load adjustments (in terms of total grid generation load and/or
27 material changes to the seasonal load shape due to connection or removal of a major
28 industrial load). Yukon Energy bears the risk between GRA years for changes in thermal
29 generation from forecast for these amounts that are netted out of the DCF determinations.

30
31 More specifically, the approach to determining the DCF year-end adjustments specifically
32 separates thermal generation related to load variation from forecast (where utilities
33 continue to bear the risk) from thermal generation related to water variability (where
34 ratepayers continue to bear the risk). The LTA approach results in thermal generation fuel
35 costs being set based on the actual grid load and related LTA thermal requirement per the
36 approved DCF Term Sheet Table, which minimizes opportunities for potential forecast
37 error issues. YEC ultimately has the risk of added costs if the final year end fuel mix has

1 more than the 10% diesel assumed in the GRA forecast, or the actual grid load varies
2 from the forecast. Please see response to YUB-YEC-2-1(d).

3
4 Yukon Energy continues to review actual diesel or LNG uses in order to better understand
5 and separate out any uses that are not strictly related to water availability. Please see
6 response to YUB-YEC-2-14(b and c) and AEY-YEC-2-1.

7
8 **(b)**

9
10 Costs due to variances from forecast thermal generation fuel volumes should be assigned
11 between GRA years generally to the utility when due to total generation load forecast
12 variance¹ or thermal generation unit maintenance requirements,² and to ratepayers when
13 due to water or wind forecast variance or other specific factors for which the regulator has
14 established deferral or contingency fund cost accounts, e.g., DCF or RFID related thermal
15 generation fuel costs.

16
17 YEC is not aware of any consistent and reasonable way to isolate additional items, such
18 as operation risks related to use of water for hydro generation to the extent that these may
19 impact thermal generation costs. Such isolation has not been attempted in either the
20 LWRF or the DCF. Further, as noted in the response to YUB-YEC-1-6(b) (ERA Part 1
21 Application), YEC has well established systems to monitor its use of available water, and
22 is not aware of any material impacts on the effectiveness of LWRF or DCF determinations
23 related to the water management element of its systems' operation.

24
25 See response to YUB-YEC-2-1(d), YUB-YEC-2-2(c) and YUB-YEC-2-3(c).

¹ Yukon experience during the period of Faro mine operation highlighted YEC's capability to apply to the Board for rate adjustments immediately upon the shut down of a major customer load – and the ability of the Board to declare rates to be interim and refundable as soon the same major load is reconnected. See response to YUB-YEC-2-3(c).

² This factor is recognized in YEC's 2017/18 GRA. Prior GRA's did not separate out this factor.

1 **TOPIC:** Forecast Thermal Generation

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), Appendix 2.2, page A2.2-
4 1, PDF page 55

5
6 **QUOTE:** This table provides (under “Existing Forecast”) a thermal
7 generation forecast, based on ST forecast hydro, of 1,130.0 MW.h
8 for 2017 and 1,084.4 MW.h for 2018, excluding requirements for
9 maintenance and capital projects (each of which is not affected by
10 selection of ST versus LTA forecasts for hydro generation).

11
12 **PREAMBLE:**

13
14 **QUESTION:**

- 15
16 a) From the June 2017 Application under the Existing Forecast 2017 and 2018
17 columns, for the row total thermal, the amounts are 2,172 and 2010 MW.h.
18 Please explain how the capital and maintenance amounts for each of 2017 and
19 2018 were determined.

20
21 **ANSWER:**

22
23 **(a)**

24
25 Capital thermal amounts for 2017 and 2018 were forecast by determining which capital
26 projects would require the use of thermal, how many weeks of thermal would be required,
27 and the location of the thermal generation (Dawson, Mayo and Faro).

28
29 Maintenance thermal amounts for 2017 and 2018 were forecast by determining which
30 months would not require the use of thermal engines (for each of diesel and LNG), and
31 adding up the average amount required for run-ups and testing during those months.

1 **TOPIC:** ST Hydro

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), Appendix 2.2, page
4 A2.2-1 to A2.2-2, PDF pages 55-56
5

6 **QUOTE:** The final month of 2018 was forecast based on the ST forecast
7 reservoir levels as at the end of November 2018.
8

9 The ST Alternative GRA Forecast for 2018 differs from the ST forecast
10 in Table 2.2 of the GRA, which assumed reservoir levels (all three
11 reservoirs) reset as at September 30, 2017 based on latest 5-year
12 average (2012-2016); for GRA revenue requirement forecast
13 purposes it is more reasonable (as was done for the 2012-13 GRA
14 ST forecast filings) to avoid such a reset that relies on recent history.
15 (Footnote omitted)
16

17 **PREAMBLE:**
18

19 **QUESTION:**
20

21 a) Please explain why 25 months of the LTA were not used to take the forecast to
22 December 31, 2018.
23

24 b) How was the ST forecast reservoir levels determined as at the end of November
25 2018? Please explain.
26

27 c) Please explain why it is more reasonable to avoid a reset of reservoir levels based
28 on the latest 5-year average versus a reset that relies on recent history for a short-
29 term forecast.
30

31 **ANSWER:**
32

33 **(a)**
34

35 The current ST hydro model was developed for operational guidance and only extends 24
36 months. As noted in footnote 13 of the filing, ST forecasts apply for approximately 18

1 months in terms of reflecting current water conditions and there has been no basis to
2 extend the ST model beyond 24 months.

3
4 **(b)**

5
6 The forecast reservoir levels as at the end of November 2018 were determined based on
7 the ST forecast for the prior 24 months, i.e., starting with actual water levels at November
8 29, 2016 for all three reservoirs (Aishihik, Mayo and Marsh), and thereafter assuming
9 forecast grid loads and LTA inflows for each month for the following 24 months (with
10 current constraints affecting Mayo Lake outlet and flows restrictions downstream of Mayo
11 B).

12
13 **(c)**

14
15 Experience with the Yukon grid, as well as many other hydro grids, shows that recent
16 history (e.g., the latest 5-year average for reservoir levels) provides no reliable guidance
17 as to what to expect beyond about 18 months from a current situation, i.e., a switch from
18 abundant water conditions to low water conditions in particular is not revealed by such an
19 approach.

20
21 As a result, ST forecasts that would be used to forecast GRA thermal requirements simply
22 extend current known reservoir levels using LTA water inflows and forecast grid firm loads
23 without any resets during the forecast period based on any recent 5-year averages for
24 reservoir levels.

25
26 As reviewed in footnote 13 of the filing, the 5-year average in this instance reflected a
27 period with water flow conditions higher than LTA. Accordingly, a ST forecast using the 5-
28 year average reset in this instance increases hydro generation in year 2 compared to the
29 approach adopted of extending the ST forecast without any such reset. The result is
30 considered to reduce forecast risks related to the second year.

1 **TOPIC:** Forecast for Diesel and LNG Thermal

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), Appendix 2.2, page A2.2-
4 2, PDF page 56

5
6 **QUOTE:** The ST Alternative GRA Forecast as developed above does not
7 address the allocation between diesel and LNG generation. This
8 requirement raises new issues.

9
10 **PREAMBLE:**

11
12 **QUESTION:**

13
14 a) Please explain why YEC failed to develop an allocation between diesel and LNG
15 for the ST Alternative GRA Forecast.

16
17 b) Please explain whether the impact if the LNG:diesel fuel mix is correct for the
18 LTA forecast. If there is none or if there is negligible impact, please explain how
19 this effect is mitigated using LTA.

20
21 **ANSWER:**

22
23 **(a)**

24
25 YEC did provide, subsequent to the referenced quote, an allocation between diesel and
26 LNG for the ST Alternative GRA Forecast.

27
28 As reviewed at page A2.2-2 of the filing (in the paragraph following the quote in the
29 preamble), YEC assumed a 40/60 diesel/LNG allocation of forecast ST generation for
30 each test year for the ST Alternative GRA Forecast. The reasons for this assumed
31 allocation are reviewed in the subsequent text of the filing.

32
33 Overall, the ST allocation in the filing reflected the ST hydro generation forecast and loads
34 for these two test years and the tendency for diesel generation to dominate smaller and
35 shorter duration thermal generation requirements under these forecast test year
36 conditions. Please see YUB-YEC-2-6 (c) at page 5 and YUB-YEC-1-38 for review of
37 information from Appendix 3.4 of the GRA on the tendency for diesel generation to

1 dominate smaller and shorter duration thermal generation requirements under these
2 forecast test year conditions.

3
4 The ST diesel/LNG allocation will vary depending on the forecast test year water
5 conditions, loads and assumed thermal generation capabilities. YEC has therefore
6 emphasized the risks and uncertainties related to the ST diesel/ LNG allocation provided
7 in the filing.

8
9 **(b)**

10
11 The LTA forecast adopted in the GRA Application assumed a 90/10 LNG/diesel allocation
12 of forecast LTA thermal generation, for the reasons set out in Appendix 3.4 (pages 3.4-5
13 to 3.4-7) and reviewed in response to YUB-YEC-2-6(c). As reviewed in YUB-YEC-2-22,
14 the ST Alternative GRA Forecast 60/40 LNG/diesel allocation mix is not correct or
15 appropriate for the LTA forecast in the GRA.

16
17 In summary, the LTA allocation is proposed in the GRA to ensure that revenue
18 requirement costs used to set rates provide some recognition of current limits on actual
19 LNG ability to displace all diesel generation (particularly under low loads and high-water
20 conditions). The proposed DCF year-end allocation procedure proposed starting January
21 1, 2017 adjusts YEC's year-end DCF payment into (or receipt from) the DCF as required
22 so that YEC's final fiscal year expense for total LTA thermal generation is 90% LNG and
23 10% diesel (subject to the constraint noted – see page 3.4-8 of GRA Application and
24 responses to YUB-YEC-1-43 and YUB-YEC-2-6 (a and b)).

25
26 As reviewed at page 3.4-23 of the GRA Application, at GRA forecast load for 2018 (about
27 420 GW.h) approximately 75% of the forecast LTA thermal generation occurs in 20% of
28 the water years with the worst drought conditions. This means that the LTA LNG/diesel
29 allocation is driven by the LTA thermal generation (where extended LNG operation is
30 assumed) and not by ST forecast thermal generation for these test years (where better
31 than LTA water conditions are likely to limit LNG share of thermal generation).

32
33 Overall, use of LTA hydro forecast approach is expected to provide a reasonably stable
34 basis for GRA forecast of the LNG/diesel allocation. As such, the LTA approach mitigates
35 the need to develop varying annual ST forecast LNG/diesel allocations to reflect varying
36 ST forecast water conditions and loads.

1 **TOPIC:** Forecast for Diesel and LNG Thermal

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), Appendix 2.2, page A2.2-
4 3, PDF page 57

5
6 **QUOTE:** No useful ST forecast is provided in the GRA of the diesel-LNG
7 allocation for the ST forecast thermal generation. The only prior year
8 with full year LNG generation capability showed 5,087 MW.h thermal
9 (excluding capital and RFID, but not excluding maintenance), with 2,293
10 MW.h diesel (45%) and 2,794 MW.h LNG (55%)¹⁶; the first 10 months
11 of 2017 showed 8,317 MW.h thermal (excluding capital, RFID and
12 maintenance), with 3,126 MW.h diesel (38%) and 5,190 MW.h LNG
13 (62%).
14

15 **PREAMBLE:**

16
17 **QUESTION:**

- 18
19 a) For all aspects of YEC's GRA application, does YEC use only historical data in
20 the formulation of its forecasts? Please explain.
21

22 **ANSWER:**

23
24 **(a)**

25
26 No. YEC does not use only historical data in formulation of its GRA forecasts. YEC takes
27 into consideration actual experience as well as historical information, and also considers
28 other (non-historical) pertinent available information regarding possible future events,
29 forecasts and requirements.
30

31 The referenced quotation from the ERA Two Part Application highlights the limited
32 historical information available at this time regarding actual ST uses of LNG vs diesel.
33

34 This point was provided because, as has been demonstrated in past general rate
35 applications, and in the current application, in forecasts or other assessments, YEC is
36 expected to consider and provide for review by the Board and intervenors historical actual
37 data for almost all estimates provided. For example, GRA filing tables typically show

1 approved and actual results for three to five years prior to the GRA test years [see Table
2 2.1 and 2.2; as well as Tables 3.1 through 3.15 and Tables 5.1 through 5.8 of the 2017/18
3 GRA]. Interrogatories also often request recent actual data or other historical data.
4
5 The LNG/diesel split historical information as then available was provided for review.
6 Assessments were then made for the ST Alternative GRA Forecast based on the
7 information currently available. The available information highlights the high degree of
8 uncertainty and risk related to this specific forecast.

1 **TOPIC:** Forecast for Diesel and LNG Thermal

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), Appendix 2.2, page A2.2-
4 3, PDF page 57

5
6 **QUOTE:** This alternative ST thermal forecast for the ERA Application assumes
7 a 60/40 LNG/diesel allocation of forecast ST generation for each test
8 year. This assumption reflects the tendency for diesel generation to
9 dominate smaller and shorter duration thermal generation, and the
10 lack of any useful additional assessments as to a forecast allocation
11 for each test year.

12
13 **PREAMBLE:**

14
15 **QUESTION:**

16
17 a) If the 60:40 ratio is more accurate, why did YEC not use this ratio for the GRA
18 forecast for total fuel costs? Please explain.

19
20 **ANSWER:**

21
22 **(a)**

23
24 Please see response to YUB-YEC-2-19 and YUB-YEC-2-22.

25
26 In summary, the GRA fuel costs assume the LTA alternative, and the proposed LTA 90/10
27 LNG/diesel fuel mix has no relation to the ST alternative 60/40 LNG/diesel fuel mix
28 assumed specifically for the 2017/18 test years.

29
30 The 60:40 mix for the ST alternative was provided as a reasonable forecast when
31 considering likely short term outcomes, notwithstanding the uncertainties noted. However,
32 there is no basis to consider this mix to be reasonable for the purpose of the LTA GRA
33 forecast. The time scope relevant for the ST versus LTA forecasts is totally different as
34 regards expected hydro and thermal generation, and therefore the ST forecast LNG/diesel
35 mix has no relevance to the LTA forecast LNG/diesel mix. That is, the estimate based on
36 a short term time horizon would not, nor would it be expected to be, similar to a long term

1 forecast that covers over 30 years and a much wider spectrum of grid and generation
2 scenarios.

3
4 The following are specifically noted in this regard:

- 5
6 • The ST 60:40 allocation reflects the ST hydro generation forecast and loads for
7 the specific 2017-18 test years and the tendency for diesel generation to dominate
8 smaller and shorter duration thermal generation requirements under these forecast
9 test year conditions.¹ In short, the ST LNG/diesel allocation will vary for different
10 GRA test periods depending on the forecast test year water conditions (in this case
11 favoring diesel over LNG), loads, and assumed thermal generation capabilities.
12
- 13 • The 2017/18 GRA uses a LTA forecast. When looking at the average of all 35
14 water years (rather than trying to forecast actual water conditions in the test years),
15 the 90/10 LNG/ diesel allocation is appropriate - and the ST 60:40 allocation has
16 no relevance. As reviewed at page 3.4-23 of the GRA Application, at GRA forecast
17 load for 2018 (about 420 GW.h) approximately 75% of the forecast LTA thermal
18 generation occurs in 20% of the water years with the worst drought conditions.
19 This means that the LTA LNG/diesel allocation is driven by the LTA thermal
20 generation (where extended LNG operation is assumed) and not by ST forecast
21 thermal generation for these specific test years (where better than LTA water
22 conditions are likely to limit LNG share of thermal generation).
23

24 Please also see response to JM-YEC-2-4 (a and b).

¹ Please see YUB-YEC-2-6 (c) at page 5) and YUB-YEC-1-38 for review of information from Appendix 3.4 of the GRA on the tendency for diesel generation to dominate smaller and shorter duration thermal generation requirements under these forecast test year conditions.

1 **TOPIC:** Forecast for Diesel and LNG Thermal

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), Appendix 2.2, page A2.2-
4 3, PDF page 57

5
6 **QUOTE:** It is apparent that there is a considerable risk, absent any change in the
7 forecast total Firm Load Generation, that the diesel/LNG allocation in
8 each test year could be very different than assumed in this alternative
9 ST thermal forecast.

10
11 **PREAMBLE:**

12
13 **QUESTION:**

14
15 a) How is this risk reduced under the LTA alternative? Please explain.

16
17 **ANSWER:**

18
19 **(a)**

20
21 The “risk” referenced is the risk that the LNG/diesel mix for each test year could vary from
22 the 60/40 LNG/diesel mix assumed in this alternative ST thermal forecast, even when
23 there is no change in forecast total Firm Load Generation.

24
25 The quoted statement addresses changes (excluding changes in forecast loads) that
26 could affect forecast and actual LNG/diesel fuel mix when using the ST alternative, e.g.,
27 changes in forecast water conditions, actual water conditions relative to forecasts, and
28 other factors affecting actual fuel mix (including degree of uncertainty in forecasts of the
29 fuel mix expected for any specific ST water and load forecast). Such changes can create
30 material rate impact differences in different test years.

31
32 The risk in the quoted statement has no relation to the LTA alternative, i.e., the LTA
33 alternative does not in any way rely upon ST hydro forecasts for the LNG/diesel mix and
34 therefore is not exposed to the “risk” referenced here.

35
36 In contrast to the ST alternative, the LTA alternative in the GRA proposes a mix (90/10
37 LNG/diesel) specific to a wide range of conditions (i.e., a wide range of grid generation

1 loads, and the full range of possible ST water conditions in each test year), and rules to
2 set the annual year end LNG/diesel mix as close as possible to the GRA mix (see
3 response to YUB-YEC-2-6(a and b)). Overall, the LTA alternative avoids relying on any
4 ST forecast of the fuel mix and thereby provides a smoothing mechanism relative to the
5 ST alternative, and this reduces risks of material test year rate change impacts being
6 required.

7
8 When comparing LTA and ST hydro forecast alternatives, the LTA alternative reduces the
9 factors that can affect fuel mix for both the GRA and the final year end determinations
10 (and this reduction in turn reduces the overall risk to rate stability related to the fuel mix
11 adopted in a GRA forecast):

- 12
13 • When using the LTA alternative, the fuel mix in the GRA is not subject to change
14 due to short-term water conditions or grid load; in contrast, when using the ST
15 alternative, the GRA forecast fuel mix is subject to material change depending on
16 the ST forecast water conditions and/or the grid load.
- 17
18 • When using the LTA alternative, the fuel mix target at year end (i.e., relative to the
19 GRA) is not subject to change due to actual water or load conditions; in contrast,
20 when using the ST alternative, the fuel mix target appropriate for actual ST water
21 and/or load conditions may be subject to change from the GRA when actual water
22 and/or load conditions vary from the ST forecast.
- 23
24 • When using the LTA alternative, the DCF mechanism works to adjust the final
25 overall fuel mix to be as close as possible to the GRA mix; in contrast, when using
26 the ST alternative, changes from ST forecast fuel mix due to actual thermal
27 generation may need to be addressed.

28
29 Please see response to YUB-YEC-2-18(c) which notes that the use of the LTA hydro
30 forecast approach is expected to provide a reasonably stable basis for GRA forecast of
31 the LNG/diesel allocation; and mitigates the need to develop varying annual ST forecast
32 LNG/diesel allocations to reflect varying ST forecast water conditions.

33
34 The following are specifically noted in this regard:

- 35
36 • The ST allocation reflects the ST hydro generation forecast and loads for the test
37 years and the tendency for diesel generation to dominate smaller and shorter

1 duration thermal generation requirements under these forecast test year
2 conditions. As such, the ST diesel/ LNG allocation will vary depending on the
3 forecast test year water conditions, loads and assumed thermal generation
4 capabilities.

5

- 6 • As reviewed at page 3.4-23 of the GRA Application, at GRA forecast load for 2018
7 (about 420 GW.h) approximately 75% of the forecast LTA thermal generation
8 occurs in 20% of the water years with the worst drought conditions. This means
9 that the LTA LNG/diesel allocation is driven by the LTA thermal generation (where
10 extended LNG operation is assumed) and not by ST forecast thermal generation
11 for these test years (where better than LTA water conditions are likely to limit LNG
12 share of thermal generation).

1 **TOPIC:** Working Capital

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), Appendix 2.2, page A2.2-
4 3, PDF page 57

5
6 **QUOTE:** The ST forecast thermal generation cost reductions will reduce GRA
7 forecast working capital by approximately \$0.140 million in 2017 and
8 \$0.049 million in 2018 (assumed working capital impact at
9 approximately 6.93% of operating cost change, based on Schedule 2
10 of the GRA [Tab 7]).

11
12 **PREAMBLE:**

13
14 **QUESTION:**

- 15
16 a) Please provide the details showing the working capital reductions. Include an
17 electronic version (excel) with formulae intact.

18
19 **ANSWER:**

20
21 **(a)**

22
23 Please see YUB-YEC-2-23 Attachment 1 for the requested information.

24
25 Please note that the correct reduction in forecast working capital is by approximately
26 \$0.144 million in 2017 [versus \$0.140 million at page A2.2-3] and \$0.050 million in 2018
27 [versus \$0.049 million at page A2.2-3], or approximately 7.12% of the total reduction in
28 operating and maintenance costs [versus 6.93% at page A2.2-3]. The correct version of
29 the Tab 7 schedules for 2017 were filed as part of the 2017/18 Alternative GRA Forecast
30 per Order 2017-08; the above corrects the amount for 2018 compared with the Tab 7
31 schedules.

32
33 YEC notes that the above corrections do not impact required rate increase calculations as
34 the impact to the revenue requirement is less than \$400.

35
36 Please also see YUB-YEC-2-24 Attachment 1 for the impact to the revenue requirements
37 for each year.

Yukon Energy Corporation
Computation of Allowance for Working Capital
(\$000s)

Line No.	Description	Cross Ref. to Tab 7 Schedules	Proposed 2017			Proposed 2018		
			Original Filing with LTA thermal	Alternative GRA with ST thermal	Difference	Original Filing with LTA thermal	Alternative GRA with ST thermal	Difference
1	Operating and maintenance	S.5 L.5	23,363	21,341	(2,021)	23,336	22,633	(702)
2	Taxes other than income	S.5 L.6	696	696	-	708	708	-
3	Non-allowable expenses		(96)	(96)	-	(100)	(100)	-
4	Cash operating expenses		23,962	21,941	(2,021)	23,944	23,241	(702)
5	27/365		1,773	1,623	(150)	1,771	1,719	(52)
6	Inventory (three year average)		3,603	3,603	-	3,598	3,598	-
7	GST Impact on working capital	S.2A L.11	(176)	(170)	6	(159)	(157)	2
8	Working capital	S.1 L.19	5,200	5,057	(144)	5,210	5,160	(50)

1 **TOPIC: Alternative Short-Term Forecast for Other Costs**

2
3 **REFERENCE:** ERA Application, Appendix 2.2, page A2.2-3, PDF pages
4 57-58

5
6 **PREAMBLE:**

7
8 **QUESTION:**

- 9
10 a) For all of the cost changes reported in the sections titled “Alternative ST Forecast
11 for Other Costs,” please provide the calculations used to determine the reported
12 numbers. Please provide these calculations in excel format, with formulas intact
13 and references to where the input data were sourced.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Please see YUB-YEC-2-24 Attachment 1 for requested information regarding reductions
20 in rate base. The number shown for 2017 is reduction of \$0.006 million versus the \$0.007
21 million shown at the referenced text. The number shown for 2018 is reduction of \$0.003
22 million versus the \$0.002 million shown at the referenced text.

23
24 Please see YUB-YEC-2-23 Attachment 1 for requested information regarding working
25 capital changes.

Table 1: Changes in 2017 Revenue Requirement Return on Ratebase Portion (\$000)

		Original Filing	ST Alternative	Change	Note
1	Mid-Year Net Ratebase [Tab 7, Schedule 1, line 29]	\$274,459	\$274,316	-\$144	<i>Reduction in working capital requirements due to lower fuel cost</i>
2	Including, Working Capital [Tab 7, Schedule 1, line 19]	\$5,200	\$5,057	-\$144	
3	Equity portion of mid-year ratebase	<i>\$110,090</i>	<i>\$110,033</i>	<i>-\$58</i>	
4		<i>8.82%</i>	<i>8.82%</i>	<i>0.0%</i>	
5=3*4		<i>\$9,711</i>	<i>\$9,706</i>	<i>-\$5</i>	
6	Debt portion of mid-year ratebase	<i>\$164,369</i>	<i>\$164,283</i>	<i>-\$86</i>	
7		<i>2.18%</i>	<i>2.18%</i>	<i>0.0%</i>	
8=6*7		<i>\$3,578</i>	<i>\$3,577</i>	<i>-\$1</i>	
9=5+8	Total Return on Ratebase	\$13,289	\$13,283	-\$6	

Table 2: Changes in 2018 Revenue Requirement Return on Ratebase Portion (\$000)

		Original Filing	ST Alternative	Change	Note
1	Mid-Year Net Ratebase [Tab 7, Schedule 1, line 29]	\$291,627	\$291,577	-\$50	<i>Reduction in working capital requirements due to lower fuel cost</i>
2	Including, Working Capital [Tab 7, Schedule 1, line 19]	\$5,210	\$5,160	-\$50	
3	Equity portion of mid-year ratebase	<i>\$116,653</i>	<i>\$116,631</i>	<i>-\$22</i>	
4		<i>8.82%</i>	<i>8.82%</i>	<i>0.0%</i>	
5=3*4		<i>\$10,290</i>	<i>\$10,288</i>	<i>-\$3</i>	
6	Debt portion of mid-year ratebase	<i>\$174,974</i>	<i>\$174,946</i>	<i>-\$28</i>	
7		<i>2.32%</i>	<i>2.32%</i>	<i>0.0%</i>	
8=6*7		<i>\$4,058</i>	<i>\$4,057</i>	<i>\$0</i>	
9=5+8	Total Return on Ratebase	\$14,348	\$14,345	-\$3	

1 **TOPIC: Alternative Short-Term Forecast Revenue Shortfall and Rate**
2 **Increase Required**

3
4 **REFERENCE:** ERA Application, Appendix 2.2, page A2.2-4, PDF page 58
5

6 **PREAMBLE:**
7

8 **QUESTION:**
9

- 10 a) For all of the revenue requirement and revenue changes reported in the sections
11 titled "Alternative ST Forecast Revenue Shortfall and Rate Increase Required,"
12 please provide the calculations used to determine the reported numbers. Please
13 provide these calculations in excel format, with formulas intact and references to
14 where the input data were sourced.
15

16 **ANSWER:**
17

18 **(a)**
19

20 Please see YUB-YEC-2-25 Attachment 1 for requested information.
21

22 Please see response to YUB-YEC-2-11 (b) for details of revenue requirement changes for
23 2017 and 2018 test years.

**Table 4.1: YEC 2017/18 Alternative GRA
Yukon Energy Revenue Required from Rates (\$000s)**

	2017	2018
Revenue Requirement	\$46,516	\$49,160
Less: Other Revenues	\$ 253	\$ 253
Less: Secondary Sales	\$ 642	\$ 642
Revenue Required from Firm Rates	\$45,621	\$48,265
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	<u>\$ 42,301</u>	<u>\$ 42,384</u>
Additional Firm Rate Revenues Required	\$3,320	\$5,881

Table 4.2: Calculation of Required 2017 and 2018 Required Rate Increases - Alternative GRA (Rider J)

Line #			Forecast 2017	Forecast 2018
1a	Consolidated Firm Retail Sales Revenues - Base Rates	\$000	54,990	55,074
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	\$000	4,198	4,198
2a	Consolidated Rider J Revenues	\$000	6,363	6,373
2b	AEY Rider R Revenues	\$000	6,878	6,887
3=1+2	Total Consolidated Firm Sales Revenues at existing rates	\$000	72,429	72,532
4=Table 1	Retail Revenue increase required in 2017	\$000	3,320	
5=4/3	Required Rate Increase	%	4.58%	
6=3+4	Total Consolidated Firm Sales Revenues with 2017 Increase	\$000	75,749	75,857
7=Table 1	Total Revenue increase required in 2018	\$000		5,881
8=6-3	To Be Recovered from 2017 Increase	\$000		3,325
9=7-8	Total net increase required in 2018	\$000		2,556
10=9/6	Required Rate Increase in 2018	%		3.37%
11=9+6	Total Consolidated Firm Sales Revenues with 2018 Increase	\$000		78,413
12	Total Cumulative 2017 and 2018 Rate Increases (compounded)			8.11%
	Rider J Required			
13a=4/(1a+1b)	Rider J Increase Required	%	5.61%	
13b=4/(1a+1b)	Rider J Increase Required	%		4.31%
14	Existing Rider J - non-industrial	%	11.01%	
15	Existing Rider J - industrial	%	7.36%	
16=13+14	Total Rider J with increases - non-industrial	%	16.62%	20.93%
17=13+15	Total Rider J with increases - industrial	%	12.97%	17.28%
18	Cumulative Rider J increase	%		9.92%
19	Total Consolidated Firm Sales Revenues with increases	\$000	\$75,749	\$78,413

Notes:

1. Total Consolidated Retail Revenues at existing rates include revenues from YEC and AEY's residential, general service and streetlight sales.
2. Consolidated Rider J revenues at existing rates include YEC Rider J at 11.01% for YEC and AEY firm retail sales and at 7.36% for firm industrial sales.
3. AEY Rider R revenues at existing rates include AEY's interim Rider R at 11.62%R for firm retail and industrial base rate sales of YEC and AEY.

1 **TOPIC: Deferral and Reserve Accounts**

2
3 **REFERENCE:** YEC response to IR YUB-YEC-1-12, PDF pages 35-40, Tab 7,
4 Schedule 5, Line 7, Amortization of deferred costs Application, Tables
5 5-3 to 5-8, PDF pages 226-236
6

7 **PREAMBLE:** In its response to the referenced IR, YEC provided detailed information
8 concerning its deferral and reserve accounts, including continuity
9 schedules (in tables 1 to 4) for rate base amounts shown on lines 6, 8,
10 9 and 18 of Schedule 1 of Tab 7.
11

12 However, the Board is unable to cross-reference or reconcile the
13 appropriation or amortization amounts identified in the continuity
14 schedules (in tables 1 to 4) or on Tables 5-3 to 5.8 of YEC's
15 Application, to the amounts referenced on Line 7 of Schedule 5 of
16 Tab 7.
17

18 **QUESTION:**
19

- 20 a) Please provide a detailed listing of the amounts comprising YEC amortization of
21 deferred costs as shown on Line 7 of Schedule 5 of Tab 7. Where applicable,
22 please cross-reference the amounts comprising Line 7 to information provided or
23 referenced in YEC's response to IR YUB-YEC-1-12, PDF pages 35-40.
24

25 **ANSWER:**
26

27 **(a)**
28

29 A detailed listing of the amounts comprising YEC amortization of deferred costs as shown
30 on Line 7 of Schedule 5 of Tab 7 is provided as YUB-YEC-2-26 Attachment 1.

(\$000)		Proposed 2017 GRA	Proposed 2018 GRA
Amortize deferred costs, Line 7 of Schedule 5 of Tab 7		\$ 3,883	\$ 3,891

Detailed listing and Reconciliation:

Amortization of Regulatory Costs	1	\$ 622	\$ 578
Amortization of Hearing Cost Reserve Account	2	55	55
Amortization of Feasibility	3	2,372	2,493
Amortization of Relicensing	4	582	515
Amortization of Dam Safety	5	30	30
Amortization of Brushing	6	222	222

Notes:

- 1 See YEC's Application, Table 5.7 (2017) and Table 5.8 (2018), Continuity Schedule of Deferred Costs, Regulatory, Accumulated Amortization, Forecast Expenses. The total of this column is \$0.523 million in 2017 and \$0.479 million in 2018, however, it is net of amortization of contributions of \$0.099 million in 2017 and 2018.
- 2 See YEC's response to IR YUB-YEC-1-12, Table 2: Deferred Study Costs, Hearing Cost Reserve Account, Annual Appropriation
- 3 See YEC's Application, Table 5.7 (2017) and Table 5.8 (2018), Continuity Schedule of Deferred Costs, Feasibility Study, Accumulated Amortization, Forecast Expenses. The total of this column is \$1.586 million in 2017 and \$1.787 million in 2018, however, it is net of amortization of contributions of \$0.787 million in 2017 and \$0.705 million in 2018.
- 4 See YEC's Application, Table 5.7 (2017) and Table 5.8 (2018), Continuity Schedule of Deferred Costs, Relicensing, Accumulated Amortization, Forecast Expenses.
- 5 See YEC's response to IR YUB-YEC-1-12, Table 2: Deferred Study Costs, Dam Safety Review, Net Amortization
- 6 See YEC's response to IR YUB-YEC-1-12, Table 2: Deferred Study Costs, Vegetation Management, Annual Amortization

**TOPIC: Depreciation and Amortization of Contributions Expense –
Proposed Forecasts**

REFERENCE: YEC response to IR YUB-YEC-1-17(a, b), PDF pages 51-52,
Application, Schedule 6, lines 7 and 8, PDF page 287

PREAMBLE: The referenced YUB IR requested YEC to provide detailed
calculations supporting each of its proposed depreciation and
amortization expense amounts shown on lines 7 and 8, of Schedule
6 of Tab 7 for the years 2017 and 2018. The Board also requested
that the currently approved depreciation parameters (and resultant
depreciation rates) on an account by account basis be provided.

In its response, YEC provided a summary of its proposed depreciation
expense on a functional basis, but did not include the detailed
expense calculations or depreciation parameters (and corresponding
depreciation rates) on an account by account basis as requested.

QUESTION:

- a) Please provide the detailed calculations supporting YEC's proposed depreciation
and amortization expense amounts for the years 2017 and 2018 for each of YEC's
depreciation expense (line 7) and amortization of contributions and fire insurance
recoveries (line 8) as shown on Schedule 6 of Tab 7. Please provide the (line 7
and 8) calculations in a working excel workbook format with formula intact that
also includes depreciation parameters (and corresponding depreciation rates) on
an account by account basis.

ANSWER:

(a)

Detailed calculations supporting YEC's proposed depreciation expense for the years 2017
and 2018 is provided as YUB-YEC-2-27 Attachment 1. Detailed calculations supporting
YEC's proposed amortization of contributions and fire insurance recoveries for the years
2017 and 2018 is provided as YUB-YEC-2-27 Attachment 2.

1 **TOPIC:** SKTP Components

2
3 **REFERENCE:** VGC Group PPA Application, Section 4.3, page 8, PDF page 11

4
5 **QUOTE:** Yukon Energy is pursuing the SKTP at this time to improve the electrical
6 transmission infrastructure in central Yukon between Stewart Crossing
7 and Keno City; reinforce and strengthen the grid between Stewart
8 Crossing and Mayo; and replace and remove deteriorated and “end of
9 life” transmission infrastructure between Mayo and Keno City. The
10 project is being planned to ensure continued safe and reliable service
11 and to facilitate future economic development within the territory.

- 12 • The SKTP as defined for environmental review and
13 permitting, and/or for the engineering/costing work,
14 included the following components:
 - 15 o 138 kV H-frame transmission line development
16 involving the following segments:
 - 17 - L179 Stewart to Mayo (58 km) [the existing new
18 69 kV line would remain as well for this
19 segment];
 - 20 - L180 Mayo to McQuesten (31 km) [to be
21 operated at 138 kV]; and
 - 22 - L250 McQuesten to Keno City (20 km) [this
23 segment would initially be operated at 69 kV].

24
25 **PREAMBLE:**

26
27 **QUESTION:**

28
29 With respect to the above quote, in particular the *existing new 69 kV line* (L179 from
30 Stewart to Mayo), please explain:

- 31
- 32 (a) Why the L179 cannot be converted to 138 kV.
 - 33 (b) When was L179 constructed?
 - 34 (c) What is the depreciated value of the assets in place?
 - 35 (d) Why is the line to remain in place?

1 **ANSWER:**

2
3 **(a), (b) and (d)**

4
5 For clarification, L179 is the identification for the new 138 kV line that the SKTP included
6 between Stewart Crossing and Mayo. The existing 69 kV line between Stewart Crossing
7 and Mayo is identified as L176.

8
9 The existing L176 between Stewart Crossing and Mayo was brought into service in
10 September 2003 as part of the Mayo-Dawson 69 kV Transmission Project.

11
12 The SKTP YESAB Project Proposal assumed that costs and disruption to convert the L176
13 relatively new 69 kV facilities (and related transformers) would not be a cost effective
14 option to establish the proposed 138 kV connection. Retaining the existing 69 kV line,
15 among other features, allowed Yukon Energy to retain ability to use this facility for smaller
16 customer connections in the area.

17
18 Costing for the full SKTP development assumes that the 138 kV line development would
19 be operated between Stewart Crossing and the new McQuesten Substation. No costs
20 were included to provide new substation facilities at Mayo to connect the new line to the
21 Mayo hydro facility. Accordingly, the existing L176 line was needed to remain in place to
22 deliver power between Mayo and Stewart Crossing.

23
24 **(c)**

25
26 The net book value for the entire Mayo Dawson transmission assets in place today
27 approximates \$25 million. L176 accounts for approximately 26% of the overall line length
28 between Mayo and Dawson (approximate 58 km out of 223 km) and, on this basis, the net
29 book value today for assets related to L176 approximates \$6.5 million. This value does
30 not include any related or appended substation assets.

1 **TOPIC: Hyperlinks**

2
3 **REFERENCE:** Application, IR responses

4
5 **PREAMBLE:** The Board has previously stated it does not accept hyperlinks on the
6 record to its proceedings as over time those links can be broken
7 rendering the record for the proceeding to be incomplete.

8
9 **QUESTION:**

10
11 a) Please file PDF versions of all hyperlinks in the application and in the information
12 responses.

13
14 **ANSWER:**

15
16 **(a)**

17
18 Please see YUB-YEC-2-29 - Attachment 1.

19
20 This attachment provides pdf versions of the following documents where hyperlinks were
21 provided as responses to questions.

- 22
- 23 • 2006 Resource Plan – provided as response to CW-YEC-1-2-(a);
 - 24
 - 25 • 2011 Resource Plan Overview [2012/13 GRA IR Response to YEC-YEC-1-18(a)]
 - 26 – provided as response to CW-YEC-1-2(a); and cross referenced in UCG-YEC-1-
 - 27 38.
 - 28
 - 29 • Alexco Power Purchase Agreement - provided as response to UCG-YEC-1-9.
 - 30
 - 31 • 2016 Resource Plan Appendices – provided in response to YUB-YEC-1-83 (e),
 - 32 with specific appendices cross-referenced in response to the following IRs:

IR Response	2016 Resource Plan Appendix Reference
CW-YEC-1-4 CW-YEC-1-5 CW-YEC-1-7	Appendix A-4.2
CW-YEC-1-4 CW-YEC-1-5 CW-YEC-1-6	Appendix A-4.3
UCG-YEC-1-18	Appendix A-5.6
YUB-YEC-1-86	Appendix A-5.9
JM-YEC-1-31 YCS-YEC-1-9 YUB-YEC-1-78	Appendix A-5.19

1
2 Where hyperlinks were provided as footnote references / citations regarding where
3 specific facts are taken from - these have not been provided [e.g., YUB-YEC-1-55 provides
4 references to Fortis BC Rate Applications for specific facts referenced, and the referenced
5 material in this case is not provided given it is a citation and does not reference a document
6 specifically requested to be provided by a party to the proceeding].

YUB-YEC-2-29 Attachment 1
(Large attachment – please see separate pdf
document)

1 **TOPIC: Gladstone Project**

2
3 **REFERENCE:** YCS-YEC-1-12

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide the dates and documentation indicating when YEC became aware
10 that the Gladstone project would not receive DFO and First Nations support.

11
12 **ANSWER:**

13
14 **(a)**

15
16 The Kluane First Nation Council issued Order in Council number 2014-15 (Attachment 1
17 to this response) on September 19, 2014 which communicated their opposition to the
18 project.

19
20 At its 2011 General Assembly, Champagne Aishihik First Nation passed resolution 2011-
21 02 stating that "...this Assembly does not support or endorse that diversion of water from
22 the Gladstone Water System into the Sekulmun Lake for the Aishihik Lake Hydro Dam."

23
24 Note that these resolutions pre-date YEC's cancellation of the project. When YEC learned
25 of the concerns of the FN, project spending was cut back as far as possible while
26 negotiations on a path forward continued between YEC and the FNs. As late as May 2016,
27 YEC offered to review potential benefits to the FN under different delivery models. In mid-
28 2016, the FN indicated their position had not changed from the date of the initial refusal of
29 support so YEC stopped the project.

30
31 DFO raised concerns about the proposed project, however they did not explicitly state a
32 lack of support. YEC did not proceed with the project because of the FN denial of support;
33 it was concluded that the project had virtually zero chance of success without FN support.



KLUANE FIRST NATION

Box 20 • Burwash Landing, Yukon • Y0B 1V0

Tel.: 867/841-4274 • Fax: 867/841-5900 • Website: www.kfn.ca

NUMBER: 2014-25

DATE: SEPTEMBER 18, 2014

TITLE: GLADSTONE LAKES DIVERSION PROJECT

WHEREAS:

- A. The Kluane First Nation is extremely concerned with the potential impacts of the proposed Gladstone Lakes Diversion Project ("Gladstone Project") on our First Nation's treaty rights under the *Kluane First Nation Final Agreement*, and our aboriginal rights and interests pursuant to common law in the Gladstone region;
- B. The Yukon Energy Corporation (YEC) completed a 20 year plan for the energy projects in the Yukon and carried out community consultation meetings in the spring of 2013. YEC advances hydro as the best and cheapest option, and overall the long term solution to the Yukon's energy requirements. It asserts that expanding the Aishihik dam size and adding two more turbines is going to provide energy certainty to the Yukon. Alternatively, KFN is advocating renewable energy as a viable alternate option for Yukon's energy demands;
- C. On page 30 of the YEC 20 year plan there is a reference that says, "In terms of hydroelectric sites, the UFA allows for 10 sites to be noted. As not all the Yukon First Nations have settled land claims, 6 of 10 sites have been designated as protected by notation: Teslin (Morley river), Champagne Aishihik (Aishihik, Long lake, Hutshi Creek and Gladstone), Tr'ondek hwech'in (North Fork), Selkirk (Granite Canyon), Natcho Nyak Dun (Hess River) and Kluane (Gladstone lake). The expansion of the Aishihik dam will not go ahead if First Nations do not agree with it;
- D. The Department of Fisheries and Oceans indicated that there is legislation that states two watersheds cannot be mixed, which the Gladstone Project would do;
- E. Jenessa Tlen, KFN Citizen, has worked with Yukon Energy Researchers to carry out extensive research on the Gladstone Project and reported the negative impacts that the Project would have on the KFN people and their traditional lands;
- F. KFN has site specific locations which would be under water if the Gladstone Project was implemented;
- G. Community consultations have been conducted and community information sessions have been carried out. There is NO Citizen or local support for the Project to proceed.

THEREFORE BE IT RESOLVED THAT:

1. The Kluane First Nation Council opposes the Gladstone Lakes Diversion Project.

Chief

Deputy Chief

Councillor

Councillor

Councillor

23 Oct/14
Date
Oct. 23/14
Date
Oct 23, 2014
Date
Oct. 23, 2014
Date
Oct 23, 2014
Date

From: [Lawrence Joe](#)
To: [Michael Brandt](#)
Cc: [Roger Brown](#)
Subject: RE: Changes to Federal Fisheries Act
Date: June-27-16 11:33:18 AM
Attachments: [image001.png](#)
[image002.png](#)
[image003.png](#)
[image004.png](#)
[image005.png](#)

Hi Micheal
 Thanks

The following is our 2010 and 2011 GA Resolutions. You are correct that the 2011 it does not say oppose.
 The 2010 version provided clearer opposition, but it is the same intent. To the CAFN people, “not support or endorse” means the same as “oppose” and to interpret it differently would be at our peril

Lawrence

		Diversion Project This Assembly does not support or endorse the diversion of water from the Gladstone Water System into Sekulmun Lake for the Aishihik Lake Hydro Dam.
Gladstone Diversion Project	2010 -23	This Assembly directs that Champagne and Aishihik First Nations

		Government not to support an aspect of the Gladstone Diversion project and take all necessary steps to oppose this Gladstone project. This resolution did not pass as it was on the table when we received notice of the death of an Elder in our community and the business of the GA was closed.
Gladstone		WHEREAS the Yukon Energy Corporation has proposed to divert water from the Gladstone water system into Sekulmun Lake; and The Citizens at this Assembly are concerned that this proposed project will have

Diversion Project	2011-02	significant impacts. THEREFORE BE IT RESOLVED THAT this Assembly does not support or endorse that diversion of water from the Gladstone Water System into the Sekulmun Lake for the Aishihik Lake Hydro Dam. Passed by consensus

From: Michael Brandt [mailto:Michael.Brandt@yec.yk.ca]

Sent: Monday, June 27, 2016 11:01 AM

To: Lawrence Joe

Subject: Changes to Federal Fisheries Act

Hi Lawrence,

Following up on your concern, I have talked with my colleagues (including Andrew) and can confirm that we are not expediting any activities to avoid any potential changes to the Fisheries Act.

T h a n k s

Michael



Michael Brandt

Vice President

Telephone: 867-393-5398 | Mobile: 867-334-3760

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SM-YEC-20141008

1 **TOPIC: Alternatives to DCF and ERA Approach**

2
3 **REFERENCE:** YEC Part II Application (December 6, 2017), pages 2-10 to 2-11.

4
5 **QUOTE:** ... Yukon Energy is not aware of any applicable alternative to the
6 requirement for a thermal cost or contingency fund account similar to
7 the DCF to ensure that ratepayers bear the risks related to water
8 variability, and to provide a fund for dealing with thermal cost
9 variability due to water variability.

10
11 **PREAMBLE:**

12
13 **QUESTION:**

- 14
15 a) What research did YEC undertake to determine this?
16
17 b) Did YEC review other Canadian jurisdictions? If so, what were YEC's findings?
18 Also, please provide all references.
19
20 c) Do any other jurisdictions have a thermal cost or contingency fund? If so, please
21 provide examples with specific references from the regulatory body governing
22 those jurisdictions.
23
24 d) If YEC cannot provide any form of confirmation to the question in part (c), how do
25 other Canadian regulators protect ratepayers from associated risks of changing
26 thermal generation in response to water variability?

27
28 **ANSWER:**

29
30 **(a) to (d)**

31
32 See response to YUB-YEC-2-9(e) which reviews the context and approaches used in
33 other hydro-based Canadian jurisdictions (outside of Quebec). See also, the response to
34 YUB-YEC-2-3(c) which reviews the historic context going back to 1989/90 for the
35 development of contingency fund mechanisms in Yukon to address water variability risks
36 borne by ratepayers.

1 As summarized in the response to YUB-YEC-2-9(e) the context for each jurisdiction is
2 different; and as such, beyond the high level principle that ratepayers bear risks related
3 to water variability (which is respected in each of the referenced jurisdictions), the
4 specific contingency mechanisms or approaches for addressing water-related risk in
5 each jurisdiction is unique and may not be directly relevant to the Yukon context. By way
6 of example (see YUB-YEC-2-9(e) for specific references), the following are noted
7 regarding contingency funds in other jurisdictions that address in some way thermal or
8 other cost variability due to hydro generation changes related to water variability:

- 9
10 • Northwest Territories Power Corporation (NTPC) has a dedicated Fuel and
11 Water Rate Stabilization Fund (RSF) – however, the RSF as approved by the
12 NWT Public Utilities Board has been very limited in its ability to address rate
13 stabilization related to water variability and is combined in its purpose with fuel
14 price deferral account functions.
15
- 16 • Manitoba Hydro uses retained earnings (rather than a formal rate stabilization
17 fund) as a reserve to address water variability impacts on its costs and rates as
18 well as other cost risks - however, Manitoba Hydro is not rate base regulated,
19 and since the late 1980s has been rate regulated by the Manitoba Public Utilities
20 Board with a focus on long-term rate stability that includes provision to allow for
21 increased reserves (retained earnings) when conditions so allow (a target to
22 move to 25% equity to debt [versus less than 10% equity] was established in the
23 first half of the 1990s). YUB-YEC-2-9(e) - Attachment 1 provides relevant
24 Manitoba PUB directions that highlight concerns about drought and adequate
25 equity funds being built up through rates - and demonstrate that regulator
26 concerns about risk as reflected in Board Orders go beyond only drought-related
27 impacts [see pages 7-8 of Attachment 1 from YUB-YEC-2-9(e)].
28
- 29 • Newfoundland and Labrador Hydro (NLH) maintains a complex Rate Stabilization
30 Plan (RSP) that addresses water variability impacts along with many other
31 factors – however, YEC's review of NLH's mechanisms indicates that there is no
32 apparent relevance for Yukon DCF proceedings of examining further the Orders
33 and filings related to the NLH RSF.
34
- 35 • BC Hydro maintains a wide range of deferral accounts, including deferral
36 accounts that result in ratepayers being responsible for changes in energy costs
37 due to variances in water availability for the average water inflows used to set

- 1 rates – however, YEC's review of the BC Hydro experience has not indicated any
- 2 specific elements that would assist in addressing Yukon DCF issues.

1 **TOPIC: Water Storage Levels**

2
3 **REFERENCE: YEC 2016 Resource Plan**

4
5 **PREAMBLE: YEC Proposes to increase water storage capacity in the**
6 **Southern Lakes system and in Mayo Lake**

7
8 **QUESTION:**

- 9
10 a) Please confirm the statement in the preamble to this question.
11
12 b) If part (a) is confirmed please provide an update to the status and any pertinent
13 details of increasing the water levels for those areas.
14
15 c) Are increased water levels in the aforementioned areas included in YEC's 2017-
16 18 GRA forecast? Please explain.
17
18 d) The YEC website refers to a document titled "A Southern Lakes Enhanced
19 Storage Concept Overview". Please provide a copy of this document for the
20 record of this proceeding.
21

22 **ANSWER:**

23
24 **(a) and (b)**

25
26 Not confirmed. The projects do not necessarily increase water levels in Marsh Lake or
27 Mayo Lake. The following is specifically noted regarding each of these projects and how
28 they impact storage and lake water levels:
29

- 30 • **Marsh Lake Storage Enhancement Project (Southern Lakes):** The Marsh
31 Lake Storage Project (recently renamed the Southern Lakes Enhanced Storage
32 Project, or SLESP) is a means of enhancing winter energy at the Whitehorse
33 Rapids generating station to displace higher cost thermal generation that would
34 otherwise be required. As reviewed in the 2012/13 GRA, the project includes
35 capital improvements to the Lewes Lake control structure, shoreline mitigation,
36 First Nation consultation and an amendment to YEC's water licence to increase
37 the full supply level by 0.3 meters and reduce the low supply level by 0.1 meters.

1 This additional water storage would be available to YEC for hydro generation
2 over the winter period.

- 3
- 4 • **Mayo Lake Storage Enhancement Project:** The Mayo Lake Enhanced Storage
5 Project (MLESP) will not increase water levels in Mayo Lake. Specifically, the
6 project will amend the Mayo Generation Station Water Use Licence to provide for
7 up to one metre of additional draw down of Mayo Lake that would enhance the
8 long-term average renewable power generation capability of the Mayo hydro
9 facility and displace diesel generation that would otherwise be required.

10

11 Both projects are still in planning stages with earliest in service in 2022 and will not affect
12 lake levels or storage in either Mayo Lake or Marsh Lake in the test years.

13

14 For further information see Section 5.3.1.8 and Section 5.3.1.9 of the 2017/18 GRA as
15 well as responses to the following Round 1 IRs:

- 16
- 17 • For Marsh Lake Storage Enhancement Project (Southern Lakes): YUB-YEC-1-
18 84; UCG-YEC-1-35 and YCS-YEC-1-10.
 - 19
 - 20 • For Mayo Lake Storage Enhancement Project: YUB-YEC-1-85; YUB-YEC-1-48;
21 UCG-YEC-1-36; JM-YEC-1-8; JM-YEC-1-9 and YCS-YEC-1-11.

22

23 **(c)**

24

25 No, increased water levels in the Southern Lakes or Mayo Lake are not included in the
26 2017/18 generation forecasts as these projects are not expected to be completed within
27 the test years. Specifically, both are forecast to remain in WIP at the end of 2018 with
28 potential in service by 2022 [see 2017/18 GRA, Tab 5, page 5-32].

29

30 **(d)**

31

32 Please see Appendix 5.3 of the 2016 Resource Plan at link below. A pdf of this
33 document is filed as part of the response to YUB-YEC-2-29.

34

35 [http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.3 Southern Lak](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.3_Southern_Lakes_Concept_Project_Proposal.pdf)
36 [es Concept Project Proposal.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.3_Southern_Lakes_Concept_Project_Proposal.pdf)