



**YUKON ENERGY
CORPORATION**
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July 13, 2018

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

Dear Mr. Laking:

Re: Yukon Energy Corporation 2017/18 General Rate Application - Undertakings

On July 3, 2018 Yukon Energy provided responses to two undertakings, and sought additional time to complete the remaining 26 undertakings, as staff required to do this work had planned vacation time during the week of July 2-6. Yukon Energy noted that it would endeavor to provide responses to all outstanding undertakings by July 13, 2018.

Yukon Energy has completed 24 of the 26 outstanding undertakings, and these are attached. Yukon Energy's transcript review to address any required corrections is also attached.

The two remaining undertakings are Undertaking #35 and Undertaking #36 to provide 2017 and 2018 updates related to actual results. These undertakings have taken more work than initially anticipated. Yukon Energy expects to provide these early the week of July 16, 2018.

If you have any questions, please contact the undersigned.

Yours truly,

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

Ed Mollard
Chief Financial Officer

Attachments

Yukon Energy 2017-18 GRA: YUB Hearing June 26-28, 2018 – Transcript Review by YEC

General

- Title page for each day's transcript - Says "Yukon Electrical Company Limited", should read "Yukon Energy Corporation"
- Undertaking List throughout transcript – this is being addressed separately by YEC's filings with the Board

Volume 1- June 26, 2018

- P36: 15 – "surveying Whitehorse Cooper tailings" should read "serving Whitehorse Copper Tailings"
- P87: 6-11 and P115:15-21– Mr. Mollard's references in these sections to "the early '80s" should have been to "the early '90s"; further, his references in these sections to "a short term model" should have been to "the short term forecasts". At P115:18-21, the Low Water Reserve Account was approved in the 1991/92 GRA (not in 1989 as stated in transcript), and used short term forecasts for hydro generation (not long term average hydro forecasts as stated in transcript). [As stated at P115:22-23, the DCF was established as part of the negotiated settlement for the 1996/97 GRA - the long-term average hydro forecast was first adopted when the DCF was established.]
- P46: 15 - "XM models" should read "YECSIM models"
- P128: 16 – "project certain people" should read "protect certain people"
- P154: 16 – "secondly" should read "secondary"
- P157: 8 – "ER payment" should read "ERA payment"
- P158: 6 – "is approved" should read "as approved"

Volume 2 – June 27, 2018

- P236: 18 – "in 20 years" should read "in 20 percent of the years"
- P239: 6-11 – Mr. Osler says that the 490 GW.h load LTA "went to the same DCF table" as the other load scenarios in the Table at page 3 of JM-YEC-1-21 revised, referencing Table 3.4-1 of the Application. Mr. Osler wants to correct this statement. Table 3.4-1 of the Application assumes only the Minto mine load with overall load net of wind only up to 485 GW.h. Assessments of LTA hydro and thermal generation with the addition of VGC load (which was assumed for the 490 GW.h load scenario) required and utilized adjusted YECSIM analysis to reflect the changed seasonal grid load shape with this added major industrial load (with its focus on summer season load) – the adjusted

YECSIM analysis otherwise included the same water years and Mayo restrictions as adopted for Table 3.4-1 of the Application.

- P240:6 – “have mines connected” should read “have no mines connected”
- P277: 23 - reference here to “Manitoba Hydro” should read “Quebec Hydro”
- P326: 19-20 – “any royal LNG (verbatim) units” should read “any additional LNG units”
- P386: 7 – “site management” should read “side management”
- P402: 1 – “YUD-YEC-1-83” should read “YUB-YEC-1-83”

Volume 3 – June 28, 2018

- References to “Enercan” 483: 9, 483:12, 484: 19 – should read “NRCan”
- P540:2-5 - Mr. Mollard was to check on general provisions in the GRA for wage increases for the test years, and confirm if this was 2 percent in each test year. On review, Mr. Mollard confirms that the GRA assumed 2 percent wage increase in 2017 and 1.75% wage increase in 2018.
- P532:24 to P533:1 – Mr. Mollard states that the notes to Table 1 of YUB-YEC-2-26 “those calculation [in Table 1] are net of amortization contributions of \$0.099 million”. On review, Mr. Mollard wants to correct this to read “those calculation [in Table 1] are before deduction of amortization contributions of \$0.099 million”.
- P595:18 – To clarify, Mr. Osler’s reference to “this particular utility in British Columbia” was to FortisBC Energy Inc. (FBC), which is also referenced to as FortisBC Electric.
- P597:11-12: Mr. Osler accepted, subject to check, that a Stage 2 process is currently ongoing. Subsequent review of the BCUC website has failed to identify any current or ongoing Stage 2 BCUC process.
- P629:13-14 – where reads “it was for the benefit of the shareholders, and it was going to be using for that purpose...” it should read “it was not for the benefit of the shareholders, and it was not going to be used for that purpose...”

List of Undertakings from 2017/18 GRA Hearing

#	Transcript Reference	Response Provided
1.	Page 69, lines 24-25 & page 70, line 1	Exhibit B-23
2.	Page 79-80	Page 113, lines 10-18
3.	Page 93-94	Page 219, lines 10-15 & page 220, lines 1-5
4.	Page 111, lines 14-19	Page 221, lines 1-4
5.	Page 192	Page 221, lines 15-24
6.	Page 193	Page 221, lines 15-24
7.	Page 209	Page 209, lines 12-14
8.	Page 210, lines 21-24	Page 220, lines 14-19
9.	Page 228, lines 21-13	Page 231, lines 5-8
10.	Page 259, lines 4-7	Undertaking removed & replaced with #11.
11.	Page 261, lines 4-7	Page 262, lines 22-25 & page 263, lines 1-4
12.	Page 264, lines 18-23	July 3, 2018 Correspondence
13.	Page 266, lines 20-25 & page 267, lines 1-2	July 3, 2018 Correspondence
14.	Page 272, lines 12-15	Page 299, lines 9-22
15.	Page 273, lines 20-22	Page 299 line 25, & page 300, lines 1-3
16.	Page 305, lines 7-10	July 13 Correspondence
17.	Page 312, lines 19-25	July 13 Correspondence
18.	Page 338, lines 20-23	July 13 Correspondence
19.	Page 395, lines 8-10	Page 434, lines 15-17
20.	Page 402, lines 11-16	July 13 Correspondence
21.	Page 453, lines 22-25	July 13 Correspondence
22.	Page 454, lines 8-12	July 13 Correspondence
23.	Page 454, lines 19-23	July 13 Correspondence
24.	Page 472, lines 22-24	July 13 Correspondence
25.	Page 497, lines 508	July 13 Correspondence
26.	Page 498, lines 4-7	July 13 Correspondence
27.	Page 509 lines 21-25 & 510, line 1	July 13 Correspondence
28.	Page 521, lines 3-5	July 13 Correspondence
29.	Page 529, lines 8-11	July 13 Correspondence
30.	Page 533, lines 3-7	July 13 Correspondence
31.	Page 535, lines 10-12	July 13 Correspondence
32.	Page 535, lines 2-23	July 13 Correspondence
33.	Page 535, line 24 to 536, line 21	July 13 Correspondence
34.	Page 543, lines 20-25	July 13 Correspondence
35.	Page 551, line 3 to page 553, line 5	Update Tab 7 of the GRA with 2017 actual results; and provide separate updates using the LTA forecast and the ST forecast.
36.	Page 553, line 20 to Page 556, line 16	Provide a 2018 revenue requirement forecast that includes industrial and secondary sales load forecast updates per the Opening Statement using both short-term and long-term average fuel requirements.
37.	Page 593, lines 22-25	July 13 Correspondence
38.	Page 600, lines 18-21; Page 621, line 8 to Page 622, line 23.	July 13 Correspondence
39.	Page 601, lines 13-16	July 13 Correspondence
40.	Page 615, lines 18-22	July 13 Correspondence
41.	Page 637, lines 18-23	July 13 Correspondence

Undertaking # 16 at Page 305, line 7-10

Undertaking to provide a reconciliation of three numbers: \$51,863,000, \$49,723,000 and \$47,071,000 from UCG-YEC-2-18, and the 2017 unaudited financial statements [provided as UCG-YEC-1-42 Attachment 1, page A-42].

Yukon Energy Response:

The requested reconciliation of preliminary 2017 YEC revenue numbers is provided in the table at the bottom of the response. The final 2017 YEC Total Sales Revenue equals the following (\$000):

• Existing Base Rate Firm Sales:	\$38,727
• Rider J on Firm Sales – pre-interim rate:	\$ 6,952
• Secondary Sales:	<u>\$ 635</u>
• Total Revenue at Existing pre-GRA rates	\$46,314
• Interim Rider J revenue	\$ 931
• Revenue accrued to reflect GRA applied for rates	<u>\$4,319</u>
• Utility Electric Sales per Regulatory Income Statement	\$51,564
• Other Income per Regulatory Income Statement	<u>\$ 319</u>
• Total Utility Revenue per Regulatory Income Statement	<u>\$51,883</u>

Report	Reference	Amount	Amount Description	Accounting Principles
Preliminary Section 25 (March 2018)	UCG-YEC-2-42, Attachment 1, Page A-42	\$ 51,883	Total Revenue	Regulatory
Preliminary Section 25 (March 2018)	UCG-YEC-2-42, Attachment 1, Page A-5	\$ 49,723	Total Revenue	IFRS
Preliminary Actual (April 2018)	UCG-YEC-2-18, Table 2.1	\$ 47,071	Total Sales Revenue	Regulatory
Reconciliation of Preliminary Regulatory Revenue to Draft Financial Statements Total Revenue				
Total Revenue per Regulatory Income Statement		\$ 51,883		
Adjustments for compliance with IFRS				
DCF Transfer		\$ (2,775)		
Funding from Parent		\$ 565		
Fuel Price Adjustment		\$ 50		
Total Revenue per Draft Financial Statements		\$ 49,723		
Reconciliation of Preliminary Regulatory Revenue to Preliminary Total Sales Revenue				
Total Revenue per Regulatory Income Statement		\$ 51,883		
Adjustments				
Other Revenue		\$ (319)		
Rate Increase Accrual included in Regulatory Income		\$ (4,319)		
Secondary Sales Adjustment - Rider F rebate		\$ (174)		
Total Sales Revenue per Preliminary Total Sales Revenue		\$ 47,071		

Undertaking # 17 at Page 312, line 19-25 and page 313, lines 1-5

Undertaking to clarify why the CEA SAIFI five-year average of 2.81 was less than the Yukon Energy five-year average of 10.23 (as shown in Figure 2.1 at page 3.3-10 of the Application, Exhibit B-1).

Yukon Energy Response:

As noted in the Application, as a small grid YEC typically experiences a higher SAIFI frequency rate (i.e., frequency of customer interruptions) than the CEA index. Figure 2.1 at page 3.3-10 of the Application shows the YEC SAIFI at 5.66 to 15.06 during the three years 2014-2016, consistently well above the CEA SAIFI average 2.81 for the last five years.

To explain this variance, several issues contribute:

1. We have significant transmission line exposure due to the long distances of our transmission vs the number of customers that we serve;
2. We have an isolated grid which makes our system sensitive to outages of generation plants (e.g. loss of supply) in a way that inter-connected utilities in southern Canada would not; and
3. We have a radial grid with no redundancy in transmission. Again, this makes our system susceptible to event-based outages on our transmission lines (foreign interference; lightning; adverse weather).

Part of this increased frequency of interruptions is due to the YEC reporting standard which includes any outage that affects a whole YEC service area, or a community served by AEY which receives power from YEC, or an industrial customer, even though there may be fewer than 50 customers affected by the outage. Figure 2.1 at page 3.3-10 of the Application illustrates a spike in outage incidents during 2015 due to lightning and weather incidents being greater than normal with many occurring on the L250 line between Mayo and Elsa.

As noted in the Application at page 3.3-10 in Figure 2.1, the YEC SAIDI (hours of interruption per customer) and CAIDI (hours of interruption per occurrence) tend to be consistently well below the CEA average.

Undertaking # 18 at Page 338, 20-23

Undertaking to provide sole-sourced contracts for feasibility projects leading up to the construction of the LNG plant and the underlying contracts.

Yukon Energy Response:

As reported in response to YUB-YEC-1-70, Planning & Permitting actual costs for the LNG Project approximated \$2.687 million.

YEC has not been able within the context of the current proceeding to provide the requested information on which of the 3rd party contracts were sole sourced. These details are resident in hard copy contract files which have been archived off-site.

IRs in the Part 3 proceeding (YUB-YEC-1-1 and YCS/LE-YEC-1-11) indicated that the then estimated planning and permitting costs included the following (costs broken out based on February 14, 2014 Update estimate of \$2.51 million – response to YCS/LE-YEC-1-11 indicated \$0.7 million was in-house costs and \$1.8 million was 3rd Party costs):

- Supply & Transportation (\$0.41 million - excluded \$0.25 million of Fort Nelson supply-cost investigations not related to the LNG Project).
- Preliminary Engineering (\$0.32 million – this excluded \$0.29 million of preliminary engineering related to diesel plant that was not related to the LNG Project).
- Permitting & Regulatory (\$0.78 million – this was for YESAB related activities, with \$0.124 million in-house and \$0.658 million 3rd Party - the Part 3 Application costs were not included, as these were addressed separately as costs for that proceeding; also excluded \$0.1 million Life Cycle Assessments costs not required for regulatory review of the Project).
- Project Management & Owners Costs (\$0.99 million).

Undertaking # 20 at Page 402, line 11-16

Undertaking to provide the total cost for the 2016 Resource Plan that is planned to be put into rate base and the costs broken down into internal costs, and the costs for consultant groups and which consultant group was hired.

Yukon Energy Response:

The Application specifies a total cost of \$2.004 million into rate base in 2017 for the Resource Plan Update 2016 (see Section 5.3.1.6 and Table 5.7). The cost estimate broken down as requested as follows:

- Internal Costs (Labour, AFUDC, other) \$0.624 million
- External Costs – Contracts (12) under \$30k \$0.124 million
- External Costs – Other Contracts (14) \$1.256 million

External contracts over \$30,000 are listed below. Where relevant, referenced Resource Plan appendices that the consultant provided are identified.

Table 1: External Contracts over \$30,000

Consultant	Report / RP Appendix / Summary	Cost
Aasman Brand Communications	Public engagement, presentation, document production	\$0.135 million
ArticCan Energy Service	Appendix 5.1: Greenhouse Gas Emission Life Cycle Assessment of Resource Options	\$0.071 million
BC Hydro	Portfolio analysis and capacity expansion model	\$0.056 million
CBER, Envint, V3 Energy	Appendix 5.9: Wind Site Inventory	\$0.069 million
Hatch	System optimization (VISTA).	\$0.128 million
ICF	Appendix 4.5: Electric Vehicle Investigation	\$0.074 million
Ince, David	Technical Advisor (TAC member)	\$0.057 million
InterGroup, EDI, Ecofor, CNC	Appendix 5.2: Environmental, Social and Economic Attributes of Resource Options	\$0.160 million
Itron	Appendix 4.3: Long Term Load and Demand Forecast 2016-2035	\$0.094 million
KGS Group	Appendix 5.5: Aishihik Turbines Uprate Study Appendix 5.6: Mayo Hydro (MHO) Future Facility Options Concept Design Report Appendix 5.10: Geothermal Review and Site Inventory	\$0.055 million
Knight Piesold	Appendix 5.7: Small Hydro Screening Assessment	\$0.174 million

Consultant	Report / RP Appendix / Summary	Cost
	Appendix 5.16: Pumped Storage Assessment	
Midgard	Appendix 5.17: Moon Lake Pumped Storage Conceptual Study Report Appendix 5.21: Transmission Options Evaluation	\$0.073 million
Stantec	Appendix 5.12: Final FEED Report Front End Engineering Design (FEED) Study Yukon Bioenergy Demonstration Project in Haines Junction, Yukon Appendix 5.15: Thermal Energy Plan Development Study	\$0.053 million
Yukon Government, Bureau of Statistics	Appendix 3.1: Electricity Values Report	\$0.056 million

Undertaking # 21 at Page 453, line 22-25

Mr. Mollard made an undertaking to provide the cost of the transformer that was installed as part of the Mayo to Dawson transmission line project in 2004.

Yukon Energy Response:

This information is not readily available. This project was put into rates as part of the 2005 proceeding. Subsequent to the approval from the YUB, detailed project records have been put in long term storage. From current accounting records, YEC can report that the value of work put into the Dawson diesel plant as part of this project was \$681,000. The cost of the noted transformer would be included in this amount.

Undertaking # 22 at Page 454, line 18-12

Undertaking to advise as to whether, at the time the transformer was built in 2004, there were ground clearance and fencing height standards for transformers.

Yukon Energy Response:

YEC does not have ready access to the standards that would have applied at the time of construction (2004). However, YEC can confirm that the design-build contract with the constructor specified that all works were to be compliant with the Canadian Electrical Code, the Alberta Electrical and Communication Utility Code (Yukon does not have its own code) and the Building Code of Canada among others.

Undertaking # 23 at Page 454, line 19-23

Undertaking to advise as to whether the transformer that was installed as part of the Mayo to Dawson transmission Line project in 2004 was built to the standards at the time.

Yukon Energy Response:

YEC does not have ready access to the standards that would have applied at the time of construction (2004). However, YEC can confirm that the design-build contract with the constructor specified that all works were to be compliant with the Canadian Electrical Code, the Alberta Electrical and Communication Utility Code (Yukon does not have its own code) and the Building Code of Canada among others.

Undertaking # 24 at Page 472, line 22-24

Undertaking to advise as to whether the study that recommended SCADA and communications upgrades included an analysis to quantify the benefits to YEC and its customers resulting from enhanced reliability.

Yukon Energy Response:

The BBA study commissioned to update YEC's Communications Needs Assessment did not attempt to quantify the reliability benefits resulting from communications upgrades.

A number of the proposed project components resulted in an estimated annual savings in operating expenses. Although not all location upgrades resulted in cost savings, overall annual operating expense savings are estimated at \$9,000.

The report describes other benefits of the upgrades as follows:

- Reduction of unnecessary travels;
- Ability to implement a redundant Disaster Recover Site;
- Effectiveness in troubleshooting process;
- Faster response to technical problems;
- Better logging and diagnosis;
- Increase of OT and IT networks availability;
- Possibility to deploy remote configurations and updates;
- Enhanced security; and
- The OT lead hand could act as a backup resource to the IT lead hand and vice versa.

Undertaking # 25 at Page 497, line 5-8

Undertaking to verify the RTUs at Aishihik were installed in 1975 and that there has been no replacement of those RTUs at Aishihik.

Yukon Energy Response:

There are currently two RTUs at the Aishihik Plant, one that was installed in 1975 and another installed as part of the Aishihik Third Turbine project. The project component referenced in the applications (exhibit B1, page 181, lines 10-15) involves the migration of the controls from the old RTU to the new one. The old RTU will be subsequently removed.

Undertaking # 26 at Page 498, line 4-7

Undertaking to advise how many of the RTUs on the YEC system are of a similar vintage to the one in Whitehorse (S150) and what the timeline for replacement is.

Yukon Energy Response:

There are currently four RTUs on the YEC system of a similar vintage to the one in S150 that is being replaced.

- The unit in MacIntyre Substation (S170) is scheduled to be replaced in 2019.
- The unit in Whitehorse Hydro Plant P125 is currently not scheduled for replacement as it is currently functioning well; however, it is being closely monitored.
- There are two RTUs in the Whitehorse Diesel Plant. The one serving the WD3 Mirrlees engine is not expected to be replaced due to the minimal remaining life of the engine. There are no immediate plans to replace the RTU serving WD4 through WD7.

Undertaking # 27 at Page 509, line 21-25 and Page 510, line 1

Undertaking to provide a listing of existing positions in YEC functions that they currently serve that would otherwise be done by outside consultants, and then the labour charges related to that.

Yukon Energy Response:

Board Order 2013-01 regarding YEC's 2012/13 GRA directed YEC to demonstrate in its next GRA that the FTE complement levels approved in Order 2013-01 have effectively reduced the costs or use of outside consultants. FTE increases approved in Order 2013-01 in this regard included Resource Planning and Environment (6 FTE increase) and Finance, Customer Accounting & Purchasing (4.19 FTE increase).

Information summarized below confirms use of internal YEC resource planning, environment and finance positions carrying out capital activities plus administration O&M activities that would otherwise likely have been assigned to external consultants. Information also documents a material reduction in consultant costs for capital (including deferred) project activities since the last GRA. Note this analysis only captures those aspects of this work that would otherwise have been completed by an external consultant; all positions noted have other duties that do not meet this criteria (i.e. internal employee functions).

Table 1: YEC Positions – Work that Otherwise Done by Consultants (2013-2016)

Position/Project	Year	2013	2014	2015	2016	Total	Task Description
Senior Regulatory Analyst							
Regulatory Support		28,163	14,510	12,939	14,165	69,777	Regulatory support and financial analysis with respect to: - 2017-18 GRA - DCF/ERA hearing - VG PPA - Secondary sales rate change
Environmental Coordinator							
Integrated Resource Plan				2,296	42,790	45,086	GIS mapping, PM resource option updates, consultation and engagement
Aishihik Hydro Re-Licensing				14,125	29,180	43,305	Project management, GIS & data management, report review, consultation and stakeholder engagement
Waste to Energy Feasibility		21,129				21,129	Project management, communications and engagement with public
BioGas Feasibility			8,167	7,298		15,465	Project management, communications and engagement with public
LNG Feasibility & Construction		9,569	4,676	389		14,634	GIS & mapping support, EMS site audits
Climate Change Study		2,005	5,966	5,419	5,582	18,972	Project management, communications and engagement with public
EV Technical Study				4,756	6,918	11,674	Project management, review consultant reports, reporting and engagement
Vegetation Management Study					4,541	4,541	Project management, technical research, economic analysis, reporting and recommendations.
						174,806	
Resource Planner							
Integrated Resource Plan				24,238	107,333	131,571	Load forecast modelling, data analysis and results interpretation, stakeholder engagement, reporting and project management
LNG Thermal Plant		41,635	58,415	19,637	2,639	122,326	Project management - storage acquisition, stakeholder engagement, data analysis, participation in regulatory review
Mt Sumanik Wind Feasibility			552	20,034	2,537	23,123	Project Management, data analysis and reporting
Southern Lakes Enhanced Storage Project		1,182	5,800	1,545		8,527	Business case development, power benefit modelling, groundwater modelling
Whitehorse Diesel Plan Assessment		6,704				6,704	Project management, business case analysis, cost estimation
Moon Lake Hydro Project				5,834	507	6,341	PM, business case analysis, project planning
Load Forecasting				2,909		2,909	short term load forecast framework development
Mayo Lake Enhanced Storage Project				1,852	586	2,438	Business case development, power benefit modelling
Ferry Hill Wind Feasibility		783	368			1,151	Project Management
						305,090	
Energy Conservation Adviser							
Demand Side Management		97,802	130,374	93,057	53,555	374,788	Project management, stakeholder (internal and external) and community engagement, local market data collection, report writing and editing, energy savings and cost effectiveness modelling, regulatory support and panel member, program design, Energy conservation equipment research and business case development
Integrated Resource Plan				19,470	87,020	106,490	Project management, reporting writing and editing, stakeholder and community engagement, survey design
LED Streetlight Conversion		10,019	3,212	8,194	3,834	25,259	Project management, data collection and analysis, report writing, community engagement, equipment research and rate design options analysis
						506,537	

Changes in Outside Consultant Costs

Table 2 below summarizes outside consultant costs for the years 2009-2011 as provided in response to YUB-YEC-1-8 revised in the 2012/13 GRA and subsequent actual annual consultant costs for 2012 to 2017.

These outside consultant costs are concentrated in capital (including deferred) project activities, followed by administration O&M activities.

Average annual consultant costs for capital projects since 2012 have been materially lower (i.e., \$6.7 million per year, or 58%, lower) compared to the 2009-2012 period.

In contrast, administration O&M costs for consultants since 2012 have been higher (i.e., \$0.2 million per year, or 36%, higher) compared to the 2009-2012 period. The unusually high costs in 2014 of \$1.118 million reflected Mayo monitoring, sampling and ramping protocol work (\$0.199 million) as well as recruitment service fees (\$0.127 million).

Table 2: Actual Outside Consultant Costs for 2009-2017 years, \$000

Year	Capital Consulting Cost	Admin O&M Consulting Cost	Operations O&M Consulting Cost
Actual consultant costs 2009-2013 (\$000)			
2009	\$9,798	\$561	\$0
2010	\$10,758	\$466	\$43
2011	\$9,605	\$733	\$61
2012	\$16,321	\$761	\$0
Average	\$11,621	\$630	\$26
Actual consultant costs after 2013-2017 (\$000)			
2013	\$3,958	\$853	\$15
2014	\$6,637	\$1,118	\$25
2015	\$4,171	\$751	\$0
2016	\$5,406	\$794	\$9
2017	\$4,286	\$773	\$3
Average	\$4,892	\$858	\$10

Undertaking # 28 at Page 519, line 7 to Page 521, line 5

Undertaking to clarify the following:

1. Why depreciation expense varies for 2017 and 2018 under existing versus proposed scenarios, given that PPE balances are the same (see Exhibit B-1, Tab 7, schedule 3 – and statement in YUB-YEC-1-17 that attributes impact to deferred overhauls coming into rate base with GRA); and
2. Why the amortization dollars differ for existing versus proposed scenarios as shown in Exhibit B-1, Tab 7, Schedule 6, and how related contributions were addressed for 2017 and 2018.

Yukon Energy Response:

Depreciation is different under the existing versus the proposed scenarios as the proposed scenarios reflect the depreciation of assets that were previously held in WIP due to previous YUB Orders until the filing of this GRA (e.g., \$6.3 million of deferred overhauls brought into rate base under the proposed scenarios at the start of 2017). The PPE balances are determined prior to depreciation and therefore do not change, i.e., there is simply a change in classification of PPE between WIP and completed projects.

Amortization is different under the existing versus the proposed scenarios as the proposed scenarios reflect the amortization of deferred costs that were previously held in WIP due to previous YUB Orders until the filing of this GRA (e.g., projects with deferred costs forecast at less than \$1 million during the 2012/13 GRA) as well as closing of projects with the proposed scenarios (e.g., Gladstone Diversion). Contributions related to assets previously held in WIP were correspondingly held in WIP until filing of this GRA.

Undertaking # 29 at Page 529, line 8-11

Undertaking to summarize the changes between the 2012/13 Planning Cost Accounting Policy (as referred to in Board Order 2013-01) and the Planning Cost Accounting Policy provided as Appendix 5.1 to the current GRA.

Yukon Energy Response:

The changes to the Planning Cost Accounting Policy provided in Appendix 5.1 of the 2017/18 GRA compared to the Planning Cost Accounting Policy provided in the 2012/13 GRA were reviewed in the response to YUB-YEC-1-75.

This IR response noted as follows:

- Yukon Energy previously submitted an updated Planning Cost Accounting Policy for the Board's review and approval as part of the 2012/13 General Rate Application (see Appendix 5.1 of the 2012/13 GRA for the Planning Cost Accounting Policy filed at that time). The Board in Order 2013-01 noted that it did not accept the planning cost accounting policy [see paragraph 405 of Order 2013-01]. The Board specifically noted that the Board and interveners must be given the opportunity to test the prudence of all costs incurred by YEC in respect of deferred costs "... and considered "the policy as proposed would allow the inclusion of these costs without any prior scrutiny by the Board and interveners."
- The Planning Cost Accounting policy was subsequently revised to take into consideration the concerns raised by the Board in Order 2013-01. Overall, in many cases wording was changed/ added to provide greater clarity compared to provisions included in the 2012/13 version [this applies to section 2.1 and new section 2.2]. Key changes to the policy compared to the 2012/13 version are as follows:
 - **Removal of reference to "Reasonable Assurance Test"**: Section 2.3 in the 2017/18 version was altered to review reference to the "Reasonable Assurance Test" for deferral of planning costs without amortization¹ that was included in the 2012/13 version of the Planning Cost Accounting Policy. Reference to this has been removed to address the Board's


¹ The 2012/13 policy noted that "planning costs deferred without amortization must meet a "Reasonable Assurance Test": (a) Future expenditures will not be recognized as work-in-progress assets until such time as there is reasonable assurance that a Corporation commitment to construction will be made; (b) in the event a project is abandoned after this step, accrued costs will be amortized over 10 years."

concerns noted in Order 2013-01.² Section 4 was added to provide greater clarity that while YEC will close out and begin amortization of studies as prescribed by the policy, all deferred costs will be subject to a prudence review by the YUB prior to any change in customer rates.

- **Insertion of new Section 2.3:** Addressing how viability of planning cost projects will be assessed on an ongoing basis.
- **New Section 2.5:** Added to clarify how planning costs will be amortized in the event a project does not proceed. The 2012/13 version of the policy included provision for a “transition policy for 2012 & 2013 Test Years”. This was considered a “one-time” transition approach for cost in WIP at that time and intended to mitigate rate impacts from 5-year amortization of existing WIP costs for projects incurred that exceeded \$1 million. The current section 2.5 seeks to continue with this approach in order to continue to mitigate rate impacts from projects in WIP that are being closed out and that have costs in excess of \$1 million.

In order to facilitate review of changes a blackline of the new Planning Cost Account Policy compared to the 2012/13 version is provided as an attachment to this undertaking.

² The 2012/13 version of this provision [including the Reasonable Assurance Test] did not seek, or intend, to include in rates any deferred or other costs that had not been subject to review and approval by the Board. However, there was significant confusion regarding this element at the 2012/13 GRA which led to the amendments included in Appendix 5.1 of the 2017/18 GRA.

	FINANCE POLICY FA-016	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Chief Financial Officer	Planning <u>Cost Accounting Policy</u>
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2012	February 2015	<u>President & CEO/Chief Financial Officer</u>

1.0 Purpose

- 1.1 The purpose of this policy is to ~~outline~~define the accounting policy for costs incurred in relation to Planning~~planning~~ activities.
- 1.2 Planning ~~and study costs~~activities can include, but are not limited to, the following:
- New Generation Supply planning;
 - Pre-feasibility and feasibility;
 - Environmental;
 - Water management;
 - Fisheries;
 - Reconnaissance;
 - Survey and investigation; and
 - Water license renewal studies

2.0 Policy

~~2.1~~

2.1 The following planning and study costs will be recorded as an expense of the period in which they are incurred:

- a. Planning and study costs which are pure research in nature, ~~or are related.~~ It should be noted that costs of this type, if any, are not expected to ~~ongoing operations, shall be recorded as an expense of the period in which they are incurred, with the exception of planning and study costs be significant.~~
- b. Planning and study costs related to ongoing operations ~~that~~, unless it can be demonstrated that these costs provide long-term or multi-year benefits to the system ~~which will be deferred.~~

2.2 When the expected outcome of planning and study costs is to enhance the service potential or extend the useful life of an existing asset or to add new assets to the system, the related costs shall be capitalized to, and amortized ~~according this policy~~ on the same basis as, the related asset.

2.23 Planning ~~costs deferred without amortization~~ cost project categories:

- a. New generation supply – New supply projects, whether being built for energy or capacity or both, must ~~meet a “Reasonable Assurance Test”~~; include an economic analysis that demonstrates a net benefit to rate payers. For energy projects, this analysis

will typically compare a project life cycle costs to a thermal option¹; although other criteria may be warranted depending on the circumstances. Because of the large dollars and complex nature of these project, the Corporation employs a stage gate process² to financing. At each stage, the project team has to justify the economics of the project prior to receiving funding for the next stage. In this way, the Corporation minimizes the risk of spending capital dollars on unsupportable projects.; or

~~a. Future expenditures will not be recognized as work in progress assets³ until such time as there is reasonable assurance that a Corporation commitment to construction will be made.⁴~~

~~**b. In the event a project is abandoned after this step, accrued**~~

~~b. **Regulatory** - Where a project is driven by regulatory requirement (e.g. water licence renewal), the legal background will be documented on the project approval. Note the cost of regulatory proceedings initiated as part of project assessment (as defined in a) will form part of the cost of constructed asset as described in 2.2 above.~~

~~c. **System Improvements** – Relates to studies on existing infrastructure. The focus of the study is generally on a) end of life components; or b) system equipment failing to perform or performing inappropriately due to a change in operating circumstances. The objective of the study is to assess options for replacement. The assessment will look at the cost of upgrade versus the benefit achieved (e.g. improved reliability, increase functionality or flexibility, etc.).~~

2.4 Where a determination is made that a project is, or continues to be, economically viable, all project expenditures will be held in WIP until the project is completed.

2.5 If the project does not proceed, the capitalized development costs shall be amortized on a straight-line basis as follows, commencing with the next rate application period following the decision not to proceed with the project.

~~a. Where accumulated planning and studies costs are less than \$1 million – the planning and studies costs will be amortized over 10five years.~~

~~b. 2.3 PlanningWhere accumulated planning and studies costs incurred in relation to major projects that do not meet Reasonable Assurance have exceeded \$1 million – the planning and studies costs will promptly be closed out in annual stages, and amortized over 5ten years⁵.~~

¹ Lowest cap-ex, highest op-ex supply solution.

² See Attachment A attached for a description of this process.

³ That is, carried beyond each year end as a deferred cost without amortization.

⁴ Such assurance would be consistent with a decision by YEC to define a specific project location, approach, technology, etc, and/or to prepare and file a YESAB Project Proposal, enter into substantive negotiations with First Nations or project partners, preparation of engineering designs and tender materials, and arrange project financing where needed (i.e., the YEC “Commitment to Proceed” test).

⁵ This approach is adopted primarily for rate stability reasons, and is relevant for YUB regulation but not necessarily for internal IFRS accounting.

- ~~a. Costs will not be carried/deferred beyond periods of approximately 12 months — and all costs incurred within the 12-month period will be closed-out and amortized — over 5 years.~~
- ~~b. All projects will be scrutinized as part of the year-end financial review to ensure — the requirement for annual milestones and close-outs is being met.~~
 - ~~i. Tangible products or reports shall be required within the deferral period in order to demonstrate a useful “asset”.~~
 - ~~ii. If there is no demonstrable tangible product or report, the costs incurred to date will be closed-out and the balances will be written off to income in that year.~~

2.46 Planning and study costs related to water license renewals shall be deferred and amortized over the term of the renewed license.

3.0 Application

3.1 Management should use its best judgment in determining which of the above categories each specific study applies to.

~~4.0 — Transition Policy for 2012 & 2013 Test Years~~

~~4.1 — A one-time special transition approach for costs presently in WIP is to be implemented — over 2012 and 2013 test years. Transition measures are intended to mitigate rate impacts — from 5-year amortization of existing WIP costs incurred prior to Reasonable Assurance — and that have climbed to over \$1 million in the past few years.~~

~~4.2 — Where appropriate, current balances for Major Projects in WIP will be crystallized and — amortized over 10 years as follows:~~

- ~~a. Allow 10-year amortization for current (2011) major WIP projects that close-out with costs exceeding \$1 million⁶; and~~
- ~~b. Allow delay of close-out until end of 2012 for eligible projects with ongoing costs assumed in 2012⁷.~~

4.0 Rate Impact

4.1 For clarity, this policy only addresses the accounting treatment of costs. In keeping with standard regulatory process, the utility is required to file with the YUB to adjust rates for changes in corporate revenue requirement. In summary, YEC will close and begin amortization of studies as prescribed by this policy. Any rate changes created by these costs will be subject to a prudence review by the YUB prior to the rate change.

⁶This includes Marsh Lake Storage, Atlin Storage, Gladstone, Geothermal, and Waste to Energy WIP projects, including 2012 forecast spending for the major projects close-out delayed until end of 2012.

⁷The following projects are assumed to have close-out delayed until the end of 2012: Marsh Lake Storage, Gladstone and Waste to Energy.

Undertaking # 30 at Page 533, line 3-7

Undertaking to provide the composition of the deferred cost expense amounts, as listed in Tab 7, Schedule 5, Line 7, by study (i.e., by categories in the table in YUB-YEC-2-26) on a pre and post contribution basis for actual 2016 and proposed 2017 and 2018 amounts.

Yukon Energy Response:

Please see the table provided below for details on deferred cost amortization amounts for Tab 7, Schedule 5, Line 7. No feasibility contributions were deducted in 2017 and 2018; however, feasibility contributions were deducted in 2016.

Deferred Cost Amortization (Tab 7, Sched. 5, Line 7) (\$000's)	Forecast			Forecast	
	Actual 2016	Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Regulatory					
Pre contribution	425	153	622	88	577
Contributions	-	-	-	-	-
Net Regulatory	425	153	622	88	577
Hearing Cost Reserve Account	550	550	55	550	55
Feasibility					
Pre contribution	1,209	867	2,372	852	2,492
Contributions	- 1,184	-	-	-	-
Net Feasibility	25	867	2,372	852	2,492
Relicensing					
Pre contribution	582	582	582	515	515
Contributions	-	-	-	-	-
Net Relicensing	582	582	582	515	515
Dam Safety					
Pre contribution	-	-	30	-	30
Contributions	-	-	-	-	-
Net Dam Safety	-	-	30	-	30
Brushing	-	-	222	-	222
Amortization of deferred costs	1,581	2,152	3,883	2,006	3,891

Please see table below for details on deferred cost contributions for Tab 7, Schedule 5, Line 10,

	Actual 2016	Actual 2017	Forecast		Forecast	
			Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Feasibility Contributions	-	1,325	783	786	702	705
Regulatory Contributions	-	99	-	99	-	99
Customer contributions and government funding	4,102	4,115	4,119	4,122	4,130	4,134
Fire insurance recoveries	262	262	262	262	262	262
Amortization of Contributions and Fire Insurance Recoveries (Tab 7, Schedule 5, Line 10)	4,364	5,801	5,164	5,269	5,094	5,200

Undertaking # 31 at Page 535, lines 10-12

Undertaking to reconcile the differences in terminology and amounts for “regulatory costs” in Tables of YUB-YEC-1-12 and YUB-YEC 2-26.

Yukon Energy Response:

The response to YUB-YEC-2-26 Attachment 1 shows amortization of proposed Regulatory Costs of \$0.622 million in 2017 and \$0.578 million in 2018 (prior to deduction of contributions). The components of these amounts are:

	2017	2018
Rate Case Amortization	374	309
DSM Amortization	<u>248</u>	<u>269</u>
	<u>622</u>	<u>578</u>

Rate case amortization is part of the net change in Rate Case Assets in Table 4 of YUB-YEC-1-12; the related balance sheet account is separately tracked from Deferred Studies (Tab 7, Schedule 1 – Deferred studies is displayed on lines 8-12 while Rate Case is separately disclosed under line 18).

DSM amortization can be seen in Table 2 of YUB-YEC-1-12.

The amortization of balance of the accounts described in Table 2 of YUB-YEC-1-12 can be mapped directly to Amortize deferred costs reported in YUB-YEC-2-26 (subject to adjustment for contributions related to feasibility of (\$786) in 2017 and (\$705) in 2018).

Undertaking # 32 at Page 535, line 2-23

Undertaking in regards to the prior undertaking (#31) to advise if the different categories and amounts (as between the two IRs [YUB-YEC-1-12 and YUB-YEC-2-26]) are net of contributions, and any related differences in terminology.

Yukon Energy Response:

See response to undertaking #31.

Undertaking # 33 at Page 535, line 24 to page 536, line 21.

Undertaking to confirm where DSM amortization costs for 2017 and 2018 are in YUB-YEC-2-26 table (these amounts are included at line 7 of schedule 5, and table 2 of YUB-YEC-1-12).

Yukon Energy Response:

In YUB-YEC-2-26, DSM amortization costs are included under Amortization of Regulatory Costs.

Undertaking # 34 at Page 543, line 20-25

Undertaking to advise as to how the GRA forecast numbers compare in 2017 and to June 2018, with the actual and currently expected 2018 expenditures for the environmental management cost category (reference YUB-YEC-1-11).

Yukon Energy Response:

Table 3.9 of the Application shows forecast Environmental Management costs of \$0.278 million in 2017. Actual Environmental Management costs in 2017 were \$0.252 million.

Table 3.9 of the Application shows forecast Environmental Management costs of \$0.238 million in 2018. Actual Environmental Management costs to June 30, 2018 are not yet available. Actual Environmental Managements costs to March 31, 2018 were \$0.011 million compared to the March 31, 2018 GRA forecast of \$0.016 million. Current actual forecast costs for 2018 are \$0.239 million.

Undertaking # 37 at Page 593, line 22-25

Undertaking to explain the difference in the levels of new debt financing between the two forecasts (original and alternative) for 2017 and 2018 (reference page 3-22 in Application).

Yukon Energy Response:

The transcript referenced the following levels of new debt financing between the two forecasts (original and alternative) for 2017 and 2018 (reference page 3-22 in Application and 3-24 in Alternative filings):

- 2017:
 - Application \$23.821 million
 - Alternative \$23.742 million
- 2018:
 - Application \$7.004 million
 - Alternative \$7.246 million

The above new debt financing forecasts are supposed to reflect Tab 7, Schedule 11 forecasts for each test year. Review of the related Tab 7, Schedule 11 indicates that the 2018 number above for the “Alternative” forecast is incorrect (it is the number for “Existing” versus “Proposed” for 2018) – the correct number is \$7.001 million.

The minor reductions to new debt reflect the minor reductions in mid-year rate base related to working capital reductions (due to lower fuel costs) of \$0.144 million in 2017 and \$0.050 million in 2018 (see response to YUB-YEC-2-23 for details on working capital changes, and YUB-YEC-2-24 for impacts on debt cost portion of return on rate base).

Undertaking # 38 at Page 600, line 22-25, and Page 621, line 8 to Page 622, line 23

Undertaking to advise as to whether FortisBC Electric has a deferral or contingency account (and if so, how such an account differs from YEC's DCF) for changes in hydro-generation from GRA forecasts due to changes in forecast water levels, as such changes affect thermal generation fuel costs, with the result that such cost variances are ultimately borne by ratepayers.

Yukon Energy Response:

The current risk premium assessment for FortisBC Electric (FBC) is based on the earlier revenue requirement and resource plan BCUC decision from 2012.¹ As reviewed below, these BCUC decisions result in FBC power purchase expense variances (e.g., price changes, and purchase volume changes of each resource due to water variability or other factors) being ultimately 100% borne by ratepayers. As regards supply volume purchase variances related to load, FBC revenue variances due to load are also flowed 100% through to ratepayers, i.e., the FBC does not bear load forecast risks (unlike YEC).

In its 2012 decision, BCUC approved FBC's proposal for the Power Purchase Expense Variance Deferral Account (PPEVDA) as well as the proposed Revenue Variance Deferral Account.² The FBC 2012-2013 Revenue Requirements Application described these deferral accounts to include the following:³

1. PPEVDA: includes 100% deferral of power purchase expense variances during the test years, such deferred amounts to be flowed through to customers in subsequent years (so that customers only pay for the actual amount of power purchased), including provision for the following:
 - a. Load variances due to variances in customer growth, usage, or weather;
 - b. Unit price variances from forecast, including market prices compared to forecast and regulated price changes (BC Hydro rates) not known at the time of the application;
 - c. FBC's ability to displace BC Hydro purchases with lower-cost market purchases;
 - d. True-up of BPPA (Brilliant plant PPA for hydro generation) costs; or

¹ BCUC, FBC 2012-13 Revenue Requirements Application and Review of Integrated System Plan Decision, August 15, 2012.

² Ibid., pages 115-116.

³ FBC 2012-2013 Revenue Requirements Application, June 30, 2011, Tab 4, section 4.1.5 and 4.1.5.1.

- e. Factors related to the operation of the CPA (Canal Plant Agreement) affecting FBC's usage or timing of hydro generation entitlements.
2. Revenue Variance Deferral Account: This deferral account performs the same as the PPEVDA for sales revenues, i.e., 100% of variances in FBC's sales revenue are charged to the account.

In summary, FBC's PPEVDA fully defers to customers all variances in resource unit prices (similar to Rider F for YEC) as well as water variability (similar to the DCF for YEC). The FBC PPEVDA also fully defers to customers both the cost and revenue variance related to any impact from changes to load or sales.

Unlike YEC, FBC is not exposed to thermal cost risks given its access to renewable generation resource options. FBC's existing resource stack includes four existing hydro plants operated under the CPA with BC Hydro directly dispatching and FBC receiving guaranteed entitlement energy and capacity provided that the generating plants are available to be dispatched. FBC's usage of its plants to meet system requirements is therefore insulated under the CPA from hydrology risk, but is still subject to plant outages.⁴ FBC also has a long-term contract to purchase the whole output of the four hydro generating units of the Brilliant Plant, which is also a CPA entitlement plant.⁵ Other FBC supply arrangements⁶ include a Power Purchase Agreement with BC Hydro, capacity blocks from the hydro Waneta Expansion project, and ability to import electricity from the Mid-C market via existing transmission connections.

Overall, FBC's existing resource stack offers a lot of options and protections not available to YEC, given FBC's location adjacent to BC Hydro and other power supply sources. The FBC deferral account flow through of purchase power cost variances to ratepayers is not associated with a need for the same rate stability elements of the DCF contingency fund - and no analysis has been provided in the FBC resource plans to suggest a need for such rate stability elements related to potential variances in water availability.

⁴ FortisBC's 2016 Long Term Electric Resource Plan (LTERP), as filed with the BCUC on November 30, 2016, and specifically Appendix L titled "Planning Reserve Margin Report." Page 8.

⁵ Ibid.

⁶ Ibid., page 9 and 10.

Undertaking # 39 at Page 601, line 13-16

In discussion of comparative risk factors affecting YEC and FortisBC Electric, Mr. Osler provided an undertaking to verify as to whether FortisBC Electric utilizes an N-1 criteria for capacity planning purposes.

Yukon Energy Response:

The response varies depending on the time period addressed for FortisBC Electric (FBC) as regards determination of its Planning Reserve Margin (PRM). The current risk premium assessment for FBC relevant to YEC's current GRA is based on the earlier Resource Plan and revenue requirement BCUC decision from 2012.¹ However, FBC's subsequent 2016 Resource Plan has updated its capacity planning criterion.

2012 Resource Plan

The 2012 FBC Resource Plan proposed a PRM at 5% of Load Responsibility plus the Single Largest Utilized Contingency.² The Waneta Expansion (WAX) Capacity Purchase Agreement (WAX CAPA) was assessed to be a very large unit-contingency reserve accounting for a significant proportion of FBC's resource portfolio (up to 38% in some months).³

However, the August 15, 2012 BCUC decision on this FBC submission rejected the PRM proposal.⁴ FBC evidence during the proceeding suggested that the formula proposed in the Application for determining PRM may overstate PRM requirements, and that a probabilistic approach was now being examined. The BCUC concluded that a significant amount of work was still needed to develop a methodology to determine an appropriate PRM, and therefore denied the proposal to implement the PRM at that time.

2016 Resource Plan

¹ BCUC, FBC 2012-13 Revenue Requirements Application and Review of Integrated System Plan Decision, August 15, 2012.

² FortisBC 2012 Long Term Resource Plan, June 30, 2011, section 1.2.4. The selected PRM was based on the Midgard Report "FortisBC Planning Reserve Margin" attached as Appendix D to the 2012 Long Term Resource Plan.

³ Midgard Consulting Inc., Planning Reserve Margin Reserve Report (Appendix D to FBC 2012 Long Term Resource Plan), March 29, 2011; page 1, page 10. The PRM varied by month, and was estimated at 21% of peak in January 2020 (12% average for entire year 2020). The largest single contingency for most months (i.e., during peak winter months) was one WAX unit. Focus on "utilized" contingency addressed monthly variance, e.g., spring freshet months when WAX CAPA will not be required to serve load. Midgard determined that LOLE was not necessary or even practical to determine for FBC at that time (pages 17-18).

⁴ BCUC, FBC 2012-13 Revenue Requirements Application and Review of Integrated System Plan Decision, August 15, 2012. Section 5.1.3 and Section 7.2.2.

Available information⁵ indicates that FBC has currently (2016) adopted LOLE (Loss-Of-Load-Expectation) as the reliability metric for assessment of PRM adequacy, and targets a 1 day in 10 years or 0.1 day (or 2.4 hours) per year threshold. Further, FBC currently meets this criteria.

Although N-1 is not specifically addressed currently as a criteria for FBC capacity planning purposes, FBC is a member of the North West Power Pool (NWPP) contingency reserve sharing group, and is required to hold an amount of capacity equal to 3 percent of load and 3 percent of generation for contingency reserve. Under the Canal Plant Agreement (CPA) FBC also holds 2 percent of its capacity for regulating reserves.⁶

Overall, FBC's existing resource stack includes four existing hydro plants operated under the CPA with BC Hydro directly dispatching and FBC receiving guaranteed entitlement energy and capacity provided that the generating plants are available to be dispatched. FBC's usage of its plants to meet system requirements is therefore insulated under the CPA from hydrology risk, but is still subject to plant outages.⁷ FBC also has a long-term contract to purchase the whole output of the four hydro generating units of the Brilliant Plant, which is also a CPA entitlement plant.⁸ Other FBC supply arrangements⁹ that further reduce risk to FBC include a Power Purchase Agreement with BC Hydro, capacity blocks from the hydro Waneta Expansion project, and ability to import electricity from the Mid-C market via existing transmission connections.

⁵ FortisBC's 2016 Long Term Electric Resource Plan (LTERP), as filed with the BCUC on November 30, 2016, and specifically Appendix L titled "Planning Reserve Margin Report." The Planning Reserve Margin (PRM) is defined at page ES-1 of Appendix L as the dependable capacity above the expected peak demand.

⁶ Ibid., page 5.

⁷ Ibid., page 8.

⁸ Ibid.

⁹ Ibid., page 9 and 10.

Undertaking # 40 at Page 615, line 18-22

Undertaking to advise as to whether it is correct to categorize the last bullet in YUB-YEC-1-36 at PDF 1-58 as a manual adjustment to the estimates of the model.

Yukon Energy Response:

The referenced wording to be explained is in the last bullet of the response to YUB-YEC-1-36, which reads as follows:

“In the event that actual thermal requirements in above average water years are higher than estimated in the LTA simulations, the estimated LTA requirement would be increased above the levels currently estimated.”

The quote is not assuming any manual adjustment to the model results. This quote refers to the potential increase in LTA thermal requirements if the model is adjusted in future in response to actual thermal results in above average water years being consistently above the current model estimate.

In summary, the quote references a potential future adjustment to the YECSIM model (i.e., in a future GRA) in the event it is determined that the current model underestimates thermal requirements in above average water years. The outcome of such an adjustment, it was suggested, would likely be to increase future LTA requirements above levels currently estimated – however, to be cautious, this can only be confirmed at such time as any future model adjustments are completed.

The referenced quote can only be understood in the context of the overall IR question and prior response to the question. As background, YUB-YEC-1-36 addressed the following quote from page 3.4-4 of the Application:

“Other thermal generation requirements (i.e., expected generation not addressed by the LTA assessments) that may occur under higher-than-median water conditions will be assessed as required in future GRAs.”

Prior to the referenced quote, the IR response outlined evidence indicating that actual thermal generation in higher-than-median water conditions in recent years has been higher than suggested by the current YECSIM model used for this GRA.

Undertaking # 41 at Page 637, line 18-23

Undertaking to provide an example as to how the ERA would work if its operation results in YEC making a payment to AEY in relation to the ERA account.

Yukon Energy Response:

The key conditions required for a payment from YEC to AEY under the terms of the ERA adjustment provisions of rate schedule (RS) 42 are:

- Actual wholesales are less than GRA approved wholesales: and
- The resulting reduction in YEC's costs (due to LTA thermal cost savings) is greater than the resulting reduction on YEC revenues (due to the reduced RS 42 charge and reduced YEC rider revenues from AEY customers):

The attached example in Table 1 focuses on the 2012 situation where an ERA of \$501k was charged to AEY (the one such case since 2012), and simply reverses the actual ERA filing as approved for 2012. The following key changes are assumed to reverse the actual ERA filing:

1. Assumed GRA decision for 2012 test year is changed as follows:
 - a. GRA approved wholesale forecast (row A2) – changed from 296.0 to 310.264 GW.h
 - b. GRA approved firm grid load forecast, net of expected wind (row B3) – changed from 405.314 to 423.310 GW.h
2. Actual loads and Fish Lake generation for 2012 test year are changed as follows:
 - a. Actual firm wholesale forecast (row A1) – changed from 310.264 to 296.0 GW.h
 - b. Actual firm grid load forecast, net of expected wind (row B2) – changed from 423.310 to 405.314 GW.h
 - c. Actual Fish Lake generation adjustment (expected LTA less actual – row A3) – changed from +0.992 GW.h to -0.992 GW.h

Based on the above changes, Table 1 indicates an ERA rebate to AEY of \$501k (rather than the ERA charge to AEY of \$501k that was actually approved for 2012 actual loads and the GRA forecasts as approved in fact by the Board).

Table 1: Summary ERA – Hypothetical 2012 Reversed

	2012	
A Wholesales Variance for AEY (MW.h)		
Actual wholesales	296,000	A1
GRA approved wholesales assuming Fish Lake LTA generaiton	310,264	A2 [See note 1]
Fish Lake generation adjustment (expected LTA less actual)	(992)	A3 [See note 2]
Change in wholesales for ERA	(13,272)	A4=A1-A2-A3
B YEC Cost Impact per kW.h change in Wholesales		
Losses (%)	8.80%	B1 [Table 2.2 GRA]
Total YEC's actual generation net of secondary, LTA wind & FL (MWh)	405,314	B2 [See note 2]
GRA approved load forecast, net of expected wind (MWh)	423,310	B3 [See note 1]
YEC incremental generation relative to GRA approved (MW.h)	(17,996)	B4=B2-B3
YEC's actual LTA Thermal Generation (MWh)	7,926	B5 [See note 2]
GRA LTA Thermal Generation (MWh)	15,622	B6 [See note 1]
YEC Incremenal thermal generation relative to GRA approved (MWh)	(7,696)	B7=B5-B6
Incremental thermal generation for incremenal total generation (%)	42.77%	B8=B7/B4
Thermal Generation cost per GRA (\$/kW.h)	0.2871	B9 [See note 1]
YEC thermal cost change (\$/kWh wholesales)	0.1336	B10=B9*B8*(1+B1)
C YEC Revenue Impact per kW.h change in Wholesales		
Rate Schedule 42 Energy Charge (\$/kW.h wholesales)	0.08298	C1
Average YEC rider applicable to AEY retails (\$/kWh wholesales)	0.00663	C2 [See note 3]
D Net thermal cost impact on YEC (\$000)		
Wholesale Change: Cost Impact (YEC thermal generation costs)	(1,773)	D1=A4*B10
Wholesale Change: Revenue Impact (YEC revenues)	(1,272)	D2=A4*(C1+C2)+A3*C1
Cost change>revenue cost change ("Yes"=1, "No"=0)	1	D3=is D1>D2 (absolute)
ERA Charge (rebate) to AEY [Net added cost (cost saving) for YEC]	(501)	D4=D3*(D1-D2)

Notes: 1. Hypothetical Compliance Filing re: an approved Board Order.
2. Table 1 to hypothetical DCF Annual Filing for 2012
3. YEC Rider J and R revenues from AEY retail customers, divided by wholesales net of Fish Lake adjustments, each number for last six months of 2012 (when Rider J applicable); applied to 71.8% of change in wholesales (portion in last six months of 2012).