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November 30, 2017

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

Dear Mr. Laking:

Re: Utilities Consumers Group (UCG) Motion and John Maissan (JM) Motion re: Yukon Energy Corporation (YEC) Responses to Information Requests

In correspondence dated September 28, 2017, UCG made application for further information from Yukon Energy arguing that the information provided in 18 responses filed September 22, 2017 was not fully responsive; and on October 3, 2017 JM also filed correspondence requesting more complete responses from YEC for seven interrogatory responses.

On November 15, 2017, the Board issued Order 2017-09 directing YEC to provide revised responses to UCG and JM in accordance with Appendix A to Order 2017-09 by November 30, 2017. In particular, the Board noted as follows regarding the "further and better IR responses" required to be provided to UCG and JM:

- With regard to **UCG-YEC-1-4(a)**, the Board noted that YEC's response referred to responses provided to **JM-YEC-1-23(a)**, **YUB-YEC-1-5(a)** and **UCG-YEC-1-23(a-e).** The Board noted that while YEC had provided a detailed response to UCG, the underlying calculations that form the basis for Tables 1 and 2 in IR response YUB-YEC-1-5 and Table 1 of IR response JM-YEC-1-23 were not provided. The Board directed YEC to provide the underlying calculations for these tables in an Excel worksheet with formulas intact.

- With regard to **UCG-YEC-1-5**, the Board noted that while YEC provided the requested tables in its IR response, the tables were not provided in an Excel workbook showing the

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underlying calculations. The Board directed YEC to provide Tables 3.1 to 3.15 in an Excel workbook with formulas intact.

- With regard to **JM-YEC-1-21**, the Board noted that YEC's response to the motion indicated that updated information was being assessed and could be provided at such time as a PPA application related to the Victoria Gold mine was provided for review and approval of the Board. The Board directed that as YEC has updated information it should respond fully to this IR and explain "how the impacts listed on page 3.4-12 of the Application would change with the addition of the Victoria Gold mine at 62 GW.h per year [with the Minto mine load]".

In accordance with the Board's directions in Order 2017-09, Yukon Energy provides with this correspondence revised responses to the following IRs:

- In response to information requested in UCG-YEC-1-4(a), supporting Excel files for JM-YEC-1-23(a) and YUB-YEC-1-5(a);
- A revised response to UCG-YEC-1-5 that includes the supporting Excel files; and
- A revised response to JM-YEC-1-21 that includes the supporting Excel files.

If you have any questions regarding the above please call.

Yours truly,

E Mollard

Ed Mollard
Chief Financial Officer

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Appendix 3.4 Page 3.4-12 Re. summary highlights impacts with a $16 million DCF cap option.

QUESTION:

a) Please explain how these impacts would change with the addition of the Victoria Gold mine at 62 GWh per year (year 1) to the grid.

ANSWER:

(a)

The 450 GW.h load option examined in this section is a good proxy for the impact of the Victoria Gold mine absent the Minto mine.

Assessment of the 450 GW.h load relative to the 420 GW.h load forecast for 2018 with a $16 million DCF cap option indicates the following changes in impacts (see page 3.4-33):

- Helps to reduce the frequency of rate riders; and

- Increases slightly the peak year charges, i.e., a modest further increase in the DCF cap would likely be needed to remove this change.

REVISED RESPONSE

Yukon Energy has prepared an assessment of a new load scenario (in addition to the three load scenarios reviewed in Appendix 3.4, Attachment 3.4.2) using the YECSIM model that assumes the 2018 GRA load forecast (with the Minto mine) and assumed grid generation capabilities plus the addition of Victoria Gold's Eagle Gold mine at 63 GW.h/year sales.[1] Assuming average line losses at 8.8%, this load scenario assumes 490 GW.h/year of firm generation requirement. This load scenario is examined at DCF cap

[1] This level of sales is consistent with YEC's recent VGC PPA Application for forecast sales in 2020 to the Eagle Gold mine (at 63 GW.h/year), assuming that grid electricity is first supplied to this mine in March 2019 and that initial gold production occurs in June 2019. There is no prospect of this mine being connected to the grid in 2018.

options of +/- $8 million, $16 million and $22 million (the higher cap option is included to reflect the higher load).

Attached to this revised response are the following supporting revised GRA tables to include this new load scenario (see Attachment 1 to this response for the supporting revised excel file):

- Table 3.4–4: Average Annual Thermal Generation.
- Figure 3–1: Duration Curve – Grid Generation Variability over 35 Water Years.
- Table 3.4-5: Summary – DCF Cap Options – 420 & 450 & 490 GW.h/year.
- Table 3.4-8A: +/-$8 Million DCF Cap with 490 GW.h Load.
- Table 3.4-8B: +/-$16 Million DCF Cap with 490 GW.h Load.
- Table 3.4-8C: +/-$22 Million DCF Cap with 490 GW.h Load.

At the load range of 490 GW.h/year and LNG assumptions, a DCF cap increase to $16 million from the current $8 million would have the following positive impacts:

a. Increased years not needing rate riders, from 20 to 26 (out of 35) water years. This change relates to reducing the number of years with charges as well as rebates.

b. Reduction in drought year rate rider charges – no reduction in the peak drought year charge (at $11.79 million); reduces average charge year amount (for years with rate rider charges) from $4.7 million to $3.6 million.

At the load range of 490 GW.h/year and LNG assumptions, a DCF cap increase to $22 million from the current $8 million would have the following positive impacts:

a. Increased years not needing rate riders, from 20 to 28 (out of 35) water years. This change relates to reducing the number of years with charges as well as rebates.

b. Major reduction in drought year rate rider charges – reduces the peak drought year charge from $11.79 million to $5.27 million; reduces average charge year amount (for years with rate rider charges) from $4.73 million to $1.97 million.

Table 3.4-4: Average Annual Thermal Generation (Averaged Load Years for 35 Water Years)

	Average Thermal Generation by water year (GW.h)				Distribution of Annual Water Year Levels					
Water Year	**Load at 420 GW.h [approx. 2018 GRA load level]**	**Load at 380 GW.h [approx. 2018 GRA load level no mines]**	**Load at 450 GW.h [approx. 2018 GRA load level plus 30 GW.h new mine load]**	**Load at 490 GW.h [approx. 2018 GRA load level plus VG load]**		**% of Years not less than**	**Load at 420 GW.h [approx. 2018 GRA load level]**	**Load at 380 GW.h [approx. 2018 GRA load level no mines]**	**Load at 450 GW.h [approx. 2018 GRA load level plus 30 GW.h new mine load]**	**Load at 490 GW.h [approx. 2018 GRA load level plus VG load]**
1981	0.2	0.0	0.7	20.1	1	3%	107.5	55.2	117.0	125.5
1982	0.2	0.0	0.7	51.8	2	6%	58.3	18.7	76.8	120.4
1983	0.2	0.0	0.7	52.7	3	9%	53.8	6.1	71.2	113.1
1984	0.4	0.0	31.0	85.5	4	11%	50.1	0.6	70.8	105.9
1985	0.3	0.0	43.9	66.5	5	14%	35.4	0.0	61.2	101.6
1986	0.4	0.0	48.0	59.2	6	17%	33.2	0.0	58.6	85.5
1987	0.2	0.0	27.7	46.0	7	20%	31.2	0.0	54.2	66.5
1988	0.2	0.0	32.4	46.7	8	23%	24.0	0.0	48.0	66.2
1989	0.2	0.0	12.9	21.8	9	26%	16.7	0.0	43.9	65.4
1990	0.2	0.0	14.9	33.5	10	29%	14.2	0.0	35.3	64.0
1991	0.2	0.0	3.3	16.0	11	31%	13.8	0.0	32.4	61.9
1992	0.2	0.0	1.6	5.8	12	34%	12.6	0.0	31.4	59.8
1993	0.2	0.0	2.8	12.6	13	37%	11.4	0.0	31.2	59.2
1994	0.2	0.0	2.5	50.5	14	40%	6.5	0.0	31.0	53.3
1995	6.5	0.0	61.2	113.1	15	43%	5.1	0.0	30.1	52.7
1996	50.1	0.0	71.2	120.4	16	46%	3.7	0.0	27.7	51.8
1997	53.8	18.7	76.8	101.6	17	49%	1.9	0.0	26.5	51.1
1998	31.2	0.6	70.8	105.9	18	51%	1.6	0.0	25.5	50.5
1999	107.5	55.2	117.0	125.5	19	54%	0.4	0.0	24.4	50.4
2000	58.3	0.0	58.6	59.8	20	57%	0.4	0.0	22.7	46.7
2001	35.4	0.0	24.4	28.6	21	60%	0.3	0.0	21.2	46.0
2002	24.0	0.0	31.4	38.1	22	63%	0.2	0.0	14.9	44.1
2003	14.2	0.0	30.1	65.4	23	66%	0.2	0.0	12.9	38.1
2004	33.2	6.1	54.2	66.2	24	69%	0.2	0.0	10.3	33.5
2005	16.7	0.0	21.2	64.0	25	71%	0.2	0.0	4.1	28.6
2006	12.6	0.0	25.5	61.9	26	74%	0.2	0.0	3.3	28.6
2007	13.8	0.0	35.3	53.3	27	77%	0.2	0.0	2.8	21.8
2008	11.4	0.0	22.7	44.1	28	80%	0.2	0.0	2.5	20.1
2009	1.9	0.0	10.3	28.6	29	83%	0.2	0.0	1.9	16.0
2010	5.1	0.0	31.2	50.4	30	86%	0.2	0.0	1.6	16.0
2011	3.7	0.0	26.5	51.1	31	89%	0.2	0.0	1.6	12.6
2012	1.6	0.0	4.1	16.0	32	91%	0.2	0.0	1.0	11.4
2013	0.2	0.0	1.6	6.2	33	94%	0.2	0.0	0.7	6.8
2014	0.2	0.0	1.0	6.8	34	97%	0.2	0.0	0.7	6.2
2015	0.2	0.0	1.9	11.4	35	100%	0.2	0.0	0.7	5.8
LTA (Average)	13.9	2.3	28.6	51.1			13.9	2.3	28.6	51.1
Median	1.6	0.0	25.5	50.5			1.6	0.0	25.5	50.5

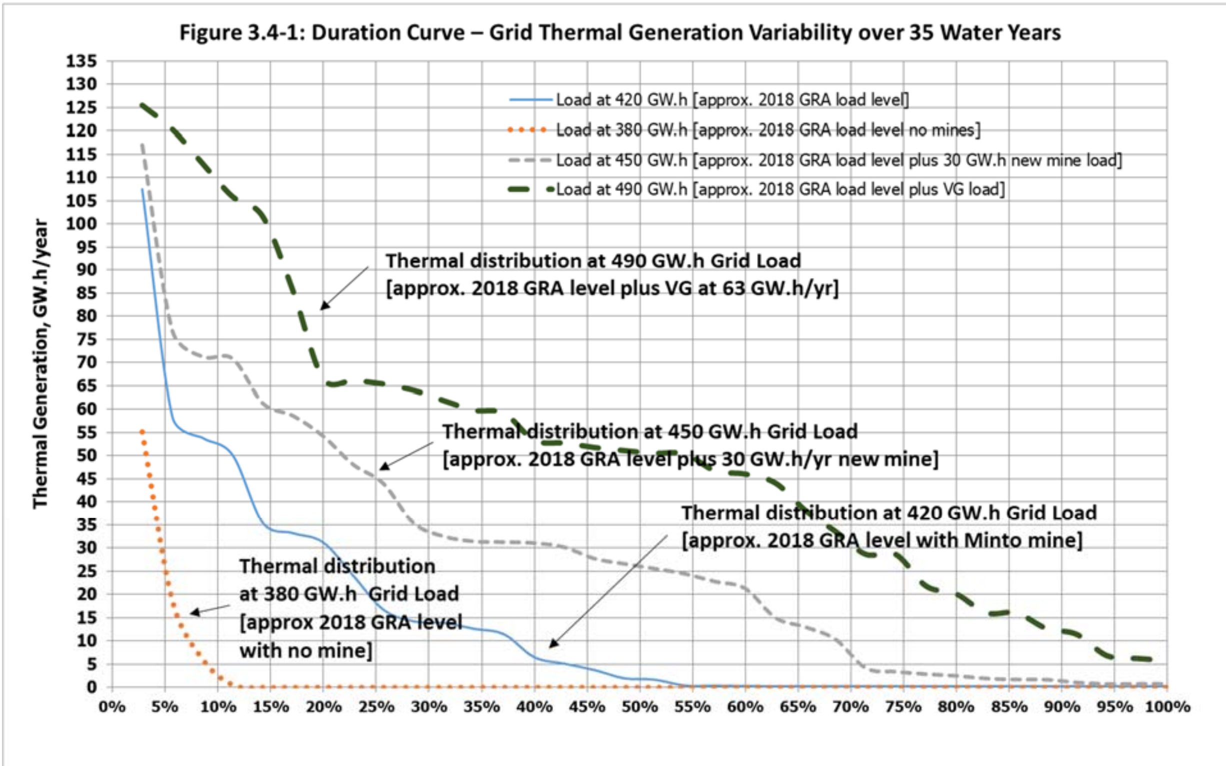
Figure 3.4-1: Duration Curve – Grid Thermal Generation Variability over 35 Water Years
Thermal Generation, GW.h/year
Load at 420 GW.h [approx. 2018 GRA load level]
Load at 380 GW.h [approx. 2018 GRA load level no mines]
Load at 450 GW.h [approx. 2018 GRA load level plus 30 GW.h new mine load]
Load at 490 GW.h [approx. 2018 GRA load level plus VG load]
Thermal distribution at 490 GW.h Grid Load [approx. 2018 GRA level plus VG at 63 GW.h/yr]
Thermal distribution at 450 GW.h Grid Load [approx. 2018 GRA level plus 30 GW.h/yr new mine]
Thermal distribution at 420 GW.h Grid Load [approx. 2018 GRA level with Minto mine]
Thermal distribution at 380 GW.h Grid Load [approx 2018 GRA level with no mine]
0 5 10 15 20 25 30 35 40 45 50 55 60 65 70 75 80 85 90 95 100 105 110 115 120 125 130 135
0% 5% 10% 15% 20% 25% 30% 35% 40% 45% 50% 55% 60% 65% 70% 75% 80% 85% 90% 95% 100%

Table 3.4-5: Summary - DCF Cap Option Impacts - 420 & 450 & 490 GW.h/yr. Loads with Minto Mine and Victoria Gold Mine

	420 GW.h/year load (13.9 GW.h/yr LTA thermal)		450 GW.h/yr load (28.6 GW.h/yr LTA thermal)		490 GW.h/yr load (50.9 GW.h/yr LTA thermal)		
	"+/-" DCF Cap ($million)		"+/-" DCF Cap ($million)		"+/-" DCF Cap ($million)		
	8	**16**	**8**	**16**	**8**	**16**	**22**
	Table 3.4-6A	Table 3.4-6B	Table 3.4-7A	Table 3.4-7B	Table 3.4-8A	Table 3.4-8B	Table 3.4-8C
DCF at 90% LNG and 10% Diesel							
Number of water years (out of 35) with							
No rate rider impact	16	21	20	26	20	26	28
Rider rebates	12	8	8	4	7	3	2
Max rebate	8	6	1	1	1	1	1
Rider charges	7	6	7	5	8	6	5
Rider Impact ($M/yr)							
Max Rebate	-2.16	-2.16	-5.06	-4.14	-7.17	-6.08	-1.05
Peak Charge	13.63	4.67	14.00	8.24	11.79	11.79	5.27
Average charge year	4.18	2.20	4.82	3.54	4.73	3.64	1.97
Net impact after 35 yrs	5.90	-2.10	8.00	5.06	8.00	14.70	8.70
DCF at 100% Diesel							
Number of water years (out of 35) with							
No rate rider impact	11	17	17	22	17	21	24
Rider rebates	15	11	10	7	9	6	4
Max rebate	9	8	1	1	1	1	1
Rider charges	9	7	8	6	9	8	7
Rider Impact ($M/yr)							
Max Rebate	-3.59	-3.59	-7.34	-7.09	-11.93	-11.93	-10.12
Peak Charge	24.66	17.27	23.28	23.28	19.60	19.60	19.60
Average charge year	6.58	6.17	8.34	8.45	8.17	7.19	6.50
Net impact after 35 yrs	8.00	7.12	8.00	16.00	8.00	16.00	22.00

Table 3.4-8A: +/- $8 Million DCF Cap with 490 GW.h Load
Impact of DCF at Cap - 2018 Example - Load at 490 GWH

Cap assumed at		**$8.00**	**million**						
LTA		51.06	GW.h						
LNG cost		0.1467	$/kWh		Blend cost	0.1583		90%	LNG (balance diesel)
Diesel cost		0.2633	$/kWh						
		DCF at 100% Diesel				**DCF at 90% LNG, 10% Diesel**			
		DCF start in 1981 - No Cap ($ Million)		**DCF - With Cap ($ million)**		**DCF start in 1981 - No Cap ($ Million)**		**DCF - With Cap ($ million)**	
Water Year	**Thermal GW.h**	**Annual**	**Total**	**Charge or (Rebate)**	**Total**	**Annual**	**Total**	**Charge or**	**Total**
1981	20.09	8.15	8.15	-$0.15	8.00	4.90	4.90		4.90
1982	51.77	-0.19	7.97		7.81	-0.11	4.79		4.79
1983	52.72	-0.44	7.53		7.38	-0.26	4.53		4.53
1984	85.50	-9.07	-1.54		-1.69	-5.45	-0.92		-0.92
1985	66.48	-4.06	-5.60		-5.75	-2.44	-3.37		-3.37
1986	59.19	-2.14	-7.74		-7.89	-1.29	-4.65		-4.65
1987	46.01	1.33	-6.41		-6.56	0.80	-3.85		-3.85
1988	46.73	1.14	-5.27		-5.43	0.68	-3.17		-3.17
1989	21.78	7.71	2.44		2.28	4.64	1.47		1.47
1990	33.52	4.62	7.06		6.90	2.78	4.24		4.24
1991	16.00	9.23	16.29	-$8.14	8.00	5.55	9.80	-$1.80	8.00
1992	5.77	11.93	28.22	-$11.93	8.00	7.17	16.97	-$7.17	8.00
1993	12.64	10.12	38.33	-$10.12	8.00	6.08	23.05	-$6.08	8.00
1994	50.52	0.14	38.47	-$0.14	8.00	0.08	23.13	-$0.08	8.00
1995	113.08	-16.33	22.14	$0.33	-8.00	-9.82	13.31		-1.82
1996	120.37	-18.25	3.89	$18.25	-8.00	-10.97	2.34	$4.79	-8.00
1997	101.60	-13.31	-9.42	$13.31	-8.00	-8.00	-5.66	$8.00	-8.00
1998	105.90	-14.44	-23.86	$14.44	-8.00	-8.68	-14.35	$8.68	-8.00
1999	125.51	-19.60	-43.46	$19.60	-8.00	-11.79	-26.13	$11.79	-8.00
2000	59.80	-2.30	-45.76	$2.30	-8.00	-1.38	-27.52	$1.38	-8.00
2001	28.57	5.92	-39.84		-2.08	3.56	-23.96		-4.44
2002	38.14	3.40	-36.44		1.32	2.05	-21.91		-2.39
2003	65.39	-3.77	-40.21		-2.45	-2.27	-24.18		-4.66
2004	66.16	-3.98	-44.19		-6.43	-2.39	-26.57		-7.05
2005	64.04	-3.42	-47.61	$1.84	-8.00	-2.06	-28.63	$1.11	-8.00
2006	61.86	-2.85	-50.45	$2.85	-8.00	-1.71	-30.34	$1.71	-8.00
2007	53.34	-0.60	-51.05	$0.60	-8.00	-0.36	-30.70	$0.36	-8.00
2008	44.10	1.83	-49.22		-6.17	1.10	-29.60		-6.90
2009	28.61	5.91	-43.31		-0.26	3.55	-26.04		-3.34
2010	50.39	0.18	-43.13		-0.08	0.11	-25.94		-3.24
2011	51.09	-0.01	-43.14		-0.09	0.00	-25.94		-3.24
2012	16.01	9.23	-33.91	-$1.14	8.00	5.55	-20.39		2.31
2013	6.21	11.81	-22.10	-$11.81	8.00	7.10	-13.29	-$1.41	8.00
2014	6.81	11.65	-10.45	-$11.65	8.00	7.01	-6.28	-$7.01	8.00
2015	11.39	10.45	0.00	-$10.45	8.00	6.28	0.00	-$6.28	8.00
Average	51.06								
			Net	8.00			Net	8.00	

Table 3.4-8B: +/- $16 Million DCF Cap with 490 GW.h Load
Impact of DCF at Cap - 2018 Example - Load at 490 GWH

Cap assumed at	**$16.00 million**			
LTA	51.06 GW.h			
LNG cost	0.1467 $/kWh	Blend cost	0.1583	90% LNG (balance diesel)
Diesel cost	0.2633 $/kWh			

		DCF at 100% Diesel				**DCF at 90% LNG, 10% Diesel**			
		DCF start in 1981 - No Cap ($ Million)		**DCF - With Cap ($ million)**		**DCF start in 1981 - No Cap ($ Million)**		**DCF - With Cap ($ million)**	
Water Year	**Thermal GW.h**	**Annual**	**Total**	**Charge or (Rebate)**	**Total**	**Annual**	**Total**	**or (Rebate**	**Total**
1981	20.09	8.15	8.15		8.15	4.90	4.90		4.90
1982	51.77	-0.19	7.97		7.97	-0.11	4.79		4.79
1983	52.72	-0.44	7.53		7.53	-0.26	4.53		4.53
1984	85.50	-9.07	-1.54		-1.54	-5.45	-0.92		-0.92
1985	66.48	-4.06	-5.60		-5.60	-2.44	-3.37		-3.37
1986	59.19	-2.14	-7.74		-7.74	-1.29	-4.65		-4.65
1987	46.01	1.33	-6.41		-6.41	0.80	-3.85		-3.85
1988	46.73	1.14	-5.27		-5.27	0.68	-3.17		-3.17
1989	21.78	7.71	2.44		2.44	4.64	1.47		1.47
1990	33.52	4.62	7.06		7.06	2.78	4.24		4.24
1991	16.00	9.23	16.29	-$0.29	16.00	5.55	9.80		9.80
1992	5.77	11.93	28.22	-$11.93	16.00	7.17	16.97	-$0.97	16.00
1993	12.64	10.12	38.33	-$10.12	16.00	6.08	23.05	-$6.08	16.00
1994	50.52	0.14	38.47	-$0.14	16.00	0.08	23.13	-$0.08	16.00
1995	113.08	-16.33	22.14		-0.33	-9.82	13.31		6.18
1996	120.37	-18.25	3.89	$2.58	-16.00	-10.97	2.34		-4.79
1997	101.60	-13.31	-9.42	$13.31	-16.00	-8.00	-5.66		-12.80
1998	105.90	-14.44	-23.86	$14.44	-16.00	-8.68	-14.35	$5.48	-16.00
1999	125.51	-19.60	-43.46	$19.60	-16.00	-11.79	-26.13	$11.79	-16.00
2000	59.80	-2.30	-45.76	$2.30	-16.00	-1.38	-27.52	$1.38	-16.00
2001	28.57	5.92	-39.84		-10.08	3.56	-23.96		-12.44
2002	38.14	3.40	-36.44		-6.68	2.05	-21.91		-10.39
2003	65.39	-3.77	-40.21		-10.45	-2.27	-24.18		-12.66
2004	66.16	-3.98	-44.19		-14.43	-2.39	-26.57		-15.05
2005	64.04	-3.42	-47.61	$1.84	-16.00	-2.06	-28.63	$1.11	-16.00
2006	61.86	-2.85	-50.45	$2.85	-16.00	-1.71	-30.34	$1.71	-16.00
2007	53.34	-0.60	-51.05	$0.60	-16.00	-0.36	-30.70	$0.36	-16.00
2008	44.10	1.83	-49.22		-14.17	1.10	-29.60		-14.90
2009	28.61	5.91	-43.31		-8.26	3.55	-26.04		-11.34
2010	50.39	0.18	-43.13		-8.08	0.11	-25.94		-11.24
2011	51.09	-0.01	-43.14		-8.09	0.00	-25.94		-11.24
2012	16.01	9.23	-33.91		1.14	5.55	-20.39		-5.69
2013	6.21	11.81	-22.10		12.95	7.10	-13.29		1.41
2014	6.81	11.65	-10.45	-$8.61	16.00	7.01	-6.28		8.42
2015	11.39	10.45	0.00	-$10.45	16.00	6.28	0.00		14.70
Average	51.06								
			Net	16.00			Net	14.70	

Table 3.4-8C: +/- $22 Million DCF Cap with 490 GW.h Load

Impact of DCF at Cap - 2018 Example - Load at 490 GWH

Cap assumed at	**$22.00 million**		
LTA	51.06 GW.h		
LNG cost	0.1467 $/kWh	Blend cost 0.1583	90% LNG (balance diesel)
Diesel cost	0.2633 $/kWh		

		DCF at 100% Diesel				DCF at 90% LNG, 10% Diesel			
		DCF start in 1981 - No Cap ($ Million)		DCF - With Cap ($ million)		DCF start in 1981 - No Cap ($ Million)		DCF - With Cap ($ million)	
Water Year	**Thermal GW.h**	**Annual**	**Total**	**Charge or (Rebate)**	**Total**	**Annual**	**Total**	**Charge or**	**Total**
1981	20.09	8.15	8.15		8.15	4.90	4.90		4.90
1982	51.77	-0.19	7.97		7.97	-0.11	4.79		4.79
1983	52.72	-0.44	7.53		7.53	-0.26	4.53		4.53
1984	85.50	-9.07	-1.54		-1.54	-5.45	-0.92		-0.92
1985	66.48	-4.06	-5.60		-5.60	-2.44	-3.37		-3.37
1986	59.19	-2.14	-7.74		-7.74	-1.29	-4.65		-4.65
1987	46.01	1.33	-6.41		-6.41	0.80	-3.85		-3.85
1988	46.73	1.14	-5.27		-5.27	0.68	-3.17		-3.17
1989	21.78	7.71	2.44		2.44	4.64	1.47		1.47
1990	33.52	4.62	7.06		7.06	2.78	4.24		4.24
1991	16.00	9.23	16.29		16.29	5.55	9.80		9.80
1992	5.77	11.93	28.22	-$6.22	22.00	7.17	16.97		16.97
1993	12.64	10.12	38.33	-$10.12	22.00	6.08	23.05	-$1.05	22.00
1994	50.52	0.14	38.47	-$0.14	22.00	0.08	23.13	-$0.08	22.00
1995	113.08	-16.33	22.14		5.67	-9.82	13.31		12.18
1996	120.37	-18.25	3.89		-12.58	-10.97	2.34		1.21
1997	101.60	-13.31	-9.42	$3.89	-22.00	-8.00	-5.66		-6.80
1998	105.90	-14.44	-23.86	$14.44	-22.00	-8.68	-14.35		-15.48
1999	125.51	-19.60	-43.46	$19.60	-22.00	-11.79	-26.13	$5.27	-22.00
2000	59.80	-2.30	-45.76	$2.30	-22.00	-1.38	-27.52	$1.38	-22.00
2001	28.57	5.92	-39.84		-16.08	3.56	-23.96		-18.44
2002	38.14	3.40	-36.44		-12.68	2.05	-21.91		-16.39
2003	65.39	-3.77	-40.21		-16.45	-2.27	-24.18		-18.66
2004	66.16	-3.98	-44.19		-20.43	-2.39	-26.57		-21.05
2005	64.04	-3.42	-47.61	$1.84	-22.00	-2.06	-28.63	$1.11	-22.00
2006	61.86	-2.85	-50.45	$2.85	-22.00	-1.71	-30.34	$1.71	-22.00
2007	53.34	-0.60	-51.05	$0.60	-22.00	-0.36	-30.70	$0.36	-22.00
2008	44.10	1.83	-49.22		-20.17	1.10	-29.60		-20.90
2009	28.61	5.91	-43.31		-14.26	3.55	-26.04		-17.34
2010	50.39	0.18	-43.13		-14.08	0.11	-25.94		-17.24
2011	51.09	-0.01	-43.14		-14.09	0.00	-25.94		-17.24
2012	16.01	9.23	-33.91		-4.86	5.55	-20.39		-11.69
2013	6.21	11.81	-22.10		6.95	7.10	-13.29		-4.59
2014	6.81	11.65	-10.45		18.61	7.01	-6.28		2.42
2015	11.39	10.45	0.00	-$7.05	22.00	6.28	0.00		8.70
Average	51.06								
			Net	22.00			Net	8.70	

TOPIC:

REFERENCE: June 22, 2017 Application, page 4
YEC states that it is requesting approval of a forecast revenue requirement of $48.544 million for 2017 and $49.864 million for 2018.

PREAMBLE:

QUESTION:

a) Please confirm that the YUB-approved revenue requirements for 2012 and 2013 were $38.850 million and $42.263 million respectively.

b) Please provide a table similar to Table 3.1 showing YUB-approved revenue requirement components and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column and include footnotes identifying the YUB orders that approved the revenue requirements.

c) Please provide a table similar to Table 3.2 showing YUB-approved fuel and purchased power costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

d) Please provide a table similar to Table 3.3 showing YUB-approved non-fuel O&M expenses and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

e) Please provide a table similar to Table 3.4 showing YUB-approved employee complement and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

f) Please provide a table similar to Table 3.5 showing YUB-approved production costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

g) Please provide a table similar to Table 3.6 showing YUB-approved transmission costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

h) Please provide a table similar to Table 3.6.1 showing YUB-approved brushing costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

i) Please provide a table similar to Table 3.7 showing YUB-approved distribution costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

j) Please provide a table similar to Table 3.8 showing YUB-approved general O&M costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

k) Please provide a table similar to Table 3.9 showing YUB-approved administration costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

l) Please provide a table similar to Table 3.10 showing YUB-approved insurance and reserve for injuries and damages costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

m) Please provide a table similar to Table 3.12 showing YUB-approved property taxes costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

n) Please provide a table similar to Table 3.13 showing YUB-approved rate base components and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

o) Please provide a table similar to Table 3.14 showing YUB-approved depreciation and amortization costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

p) Please provide a table similar to Table 3.15 showing YUB-approved cost of capital and actuals for 2012, 2013, 2014, 2015 and 2016.

ANSWER:

(a)

Confirmed.

(b) through **(p)**

Please see below copies of the tables as requested from Tab 3 of the Application for the years 2012 to 2016.

REVISED RESPONSE

The supporting excel file for the tables requested from Tab 3 of the Application for the years 2012 to 2016 is provided as Attachment 1 to this response.

Table 3.1
Yukon Energy Revenue Requirement
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fuel and Purchased Power	$ 2,316	$ 3,743	62%	$ 3,200	$ 3,878	21%	$ 1,569	-60%	$ 2,756	76%	$ 2,159	-22%
Non-Fuel Operating and Maintenance	17,210	17,769	3%	18,111	19,381	7%	19,957	3%	19,580	-2%	20,470	5%
Depreciation and Amortization	7,927	8,225	4%	8,604	9,500	10%	7,783	-18%	8,690	12%	7,816	-10%
Return on Rate Base	11,396	7,346	-36%	12,348	11,139	-10%	11,938	7%	10,829	-9%	12,242	13%
Revenue Requirement/Revenue	$ 38,850	$ 37,083	-5%	$ 42,263	$ 43,897	4%	$ 41,247	-6%	$ 41,855	1%	$ 42,686	2%

Table 3.2
Fuel and Purchased Power
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fuel	$ 2,276	$ 3,715	63%	$ 3,160	$ 3,848	22%	$ 1,528	-60%	$ 2,720	78%	$ 2,114	-22%
Purchased Power	40	28	-30%	40	30	-26%	41	38%	36	-12%	45	26%
Total Fuel and Purchased Power	$ 2,316	$ 3,743	62%	$ 3,200	$ 3,878	21%	$ 1,569	-60%	$ 2,756	76%	$ 2,159	-22%

Note:
1. Fuel costs reflect long-term average thermal generation fuel costs at forecast firm loads, maintenance and run-up requirements, and forecast fuel prices.

Table 3.3
Non-Fuel Operating and Maintenance Expenses
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 9,155	$ 9,635	5%	$ 9,348	$ 10,604	13%	$ 11,172	5%	$ 11,068	-1%	$ 11,739	6%
Production	1,449	1,552	7%	1,437	1,639	14%	1,795	10%	1,595	-11%	1,906	19%
Transmission	760	785	3%	853	1,266	49%	594	-53%	680	15%	709	4%
Distribution	201	786	292%	226	322	43%	553	72%	541	-2%	284	-47%
General O&M	1,094	901	-18%	1,154	1,224	6%	1,321	8%	1,382	5%	1,156	-16%
Administration	3,179	2,691	-15%	3,646	2,778	-24%	2,947	6%	2,585	-12%	2,726	5%
Insurance and Reserve for Injuries/Damages	1,061	1,097	3%	1,121	1,216	8%	1,243	2%	1,256	1%	1,263	1%
Property Taxes	312	322	3%	326	331	1%	331	0%	473	43%	686	45%
Total OM&A (Tab 7, Schedule 10)	$ 17,210	$ 17,769	3%	$ 18,111	$ 19,381	7%	$ 19,957	3%	$ 19,580	-2%	$ 20,470	5%

Table 3.4
Employee Complement History

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
President	4.50	4.50	0%	4.50	5.00	11%	5.00	0%	5.46	9%	5.09	-7%
Communications	1.00	1.00	0%	1.00	1.00	0%	1.00	0%	1.00	0%	1.00	0%
Human Resources & Info. Mgmt.	6.25	6.18	-1%	6.25	6.16	-1%	6.12	-1%	6.13	0%	5.20	-15%
Resource Planning and Environment	7.00	7.00	0%	7.00	7.00	0%	6.00	-14%	6.00	0%	6.00	0%
Finance, Cust. Acctg. & Purchasing	17.00	17.06	0%	17.00	16.96	0%	17.63	4%	16.81	-5%	16.87	0%
Operations	41.25	42.10	2%	41.25	42.83	4%	42.15	-2%	42.79	2%	44.15	3%
Engineering Services	13.00	12.00	-8%	13.00	12.00	-8%	13.00	8%	13.00	0%	13.00	0%
Health, Safety & Environment	2.00	2.00	0%	2.00	2.00	0%	2.00	0%	2.00	0%	2.00	0%
Total	92.00	91.84	0%	92.00	92.95	1%	92.90	0%	93.19	0%	93.31	0%

Note:
1. The employee complement numbers are net of allocation to YDC.

Table 3.5
Production Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 3,003	$ 3,262	9%	$ 3,057	$ 3,671	20%	$ 3,792	3%	$ 3,876	2%	$ 4,133	7%
Diesel	425	446	5%	439	444	1%	569	28%	430	-24%	548	27%
LNG									61		224	269%
Hydro	938	872	-7%	909	1,024	13%	1,107	8%	1,024	-8%	1,058	3%
Wind	27	34	25%	18	17	-2%	43	146%	3	-93%	14	388%
Operation Supervision	59	199	235%	72	154	115%	77	-50%	78	2%	62	-21%
Total Production	$ 4,452	$ 4,813	8%	$ 4,494	$ 5,310	18%	$ 5,588	5%	$ 5,472	-2%	$ 6,039	10%

Table 3.6
Transmission Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 431	$ 508	18%	$ 440	$ 577	31%	$ 507	-12%	$ 562	11%	$ 621	10%
Brushing Cost	505	561	11%	639	948	48%	1,161	22%	1,069	-8%	1,034	-3%
Deferred Brushing							(748)	na	(632)	-15%	(550)	-13%
Net Brushing Cost	505	561	11%	639	948	48%	413	-56%	437	6%	484	11%
Other Non-Labour	255	224	-12%	214	318	49%	180	-43%	243	35%	225	-7%
Total Transmission	$ 1,190	$ 1,293	9%	$ 1,293	$ 1,843	43%	$ 1,100	-40%	$ 1,242	13%	$ 1,330	7%

Note:
1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year, distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

Table 3.6.1
Brushing Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Transmission Brushing	505	561	11%	639	948	48%	1,161	22%	1,069	-8%	1,034	-3%
Distribution Brushing	93	157	69%	113	113	0%	262	131%	160	-39%	39	-76%
Total Brushing	598	718	20%	752	1,062	41%	1,424	34%	1,229	-14%	1,073	-13%
Transmission Deferred	na	na	na	na	na	na	748	na	632	-15%	550	-13%
Distribution Deferred	na	na	na	na	na	na	169	na	95	-44%	21	-78%
Brushing Deferred	na	na	na	na	na	na	917	na	727	-21%	571	-21%
Net Transmission Brushing	505	561	11%	639	948	48%	413	-56%	437	6%	484	11%
Net Distribution Brushing	93	157	69%	113	113	0%	93	-18%	65	-30%	18	-72%
Net Brushing Expense	$ 598	$ 718	20%	$ 752	$ 1,062	41%	$ 507	-52%	$ 502	-1%	$ 502	0%

1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

Table 3.7
Distribution Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 579	$ 758	31%	$ 592	$ 794	34%	$ 912	15%	$ 746	-18%	$ 837	12%
Brushing Cost	93	157	69%	113	113	0%	262	131%	160	-39%	39	-76%
Deferred Brushing							(169)	na	(95)	-44%	(21)	-78%
Net Brushing Cost	93	157	69%	113	113	0%	93	-18%	65	-30%	18	-72%
Other Non-Labour	108	630	483%	113	209	84%	460	120%	476	3%	266	-44%
Total Distribution	$ 780	$ 1,544	98%	$ 819	$ 1,117	36%	$ 1,465	31%	$ 1,288	-12%	$ 1,121	-13%

Note:
1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

Table 3.8
General Operating and Maintenance
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 245	$ 217	-11%	$ 250	$ 261	4%	$ 414	59%	$ 368	-11%	$ 366	-1%
Transportation	427	184	-57%	451	569	26%	550	-3%	505	-8%	459	-9%
Maintenance of Company Owned Properties	581	665	14%	611	565	-8%	552	-2%	673	22%	501	-26%
SCADA Communication	86	53	-39%	93	90	-3%	219	144%	203	-7%	197	-3%
Total General O&M	$ 1,339	$ 1,117	-17%	$ 1,405	$ 1,485	6%	$ 1,735	17%	$ 1,749	1%	$ 1,522	-13%

Table 3.9
Administration
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 4,897	$ 4,891	0%	$ 5,008	$ 5,301	6%	$ 5,547	5%	$ 5,516	-1%	$ 5,783	5%
Resource Planning	26	89	242%	26	18	-31%	9	-50%	6	-33%	14	138%
Communications	105	102	-3%	105	155	47%	100	-36%	144	44%	129	-10%
Customer Accounting	190	197	3%	191	232	21%	224	-3%	214	-4%	208	-3%
Environmental Mgmt	338	330	-2%	569	230	-60%	350	52%	273	-22%	166	-39%
General	910	438	-52%	1,099	590	-46%	741	26%	438	-41%	613	40%
Information Systems	569	536	-6%	607	481	-21%	488	1%	557	14%	576	3%
Fish Hatchery	182	154	-16%	187	169	-9%	124	-27%	162	30%	157	-3%
Safety	177	121	-32%	189	164	-13%	150	-8%	165	10%	172	4%
Training	260	146	-44%	260	161	-38%	154	-5%	169	10%	143	-15%
Recruitment	120	260	116%	120	124	3%	280	125%	296	6%	231	-22%
Board of Directors	180	112	-38%	168	150	-10%	255	70%	99	-61%	160	62%
Union	23	49	113%	23	117	407%	0	-100%	0		0	
Regulatory Affairs	34	2	-95%	34	113	232%	0	-100%	39		99	152%
Material Management	33	147	344%	35	58	66%	55	-5%	17	-69%	41	138%
Contracting	15	10	-34%	16	12	-25%	8	-35%	5	-44%	14	202%
Professional Development	17	0	-100%	17	4	-77%	9	137%	1	-89%	3	155%
Total Administration	$ 8,076	$ 7,583	-6%	$ 8,654	$ 8,080	-7%	$ 8,495	5%	$ 8,101	-5%	$ 8,509	5%

Table 3.10
Insurance and Reserve for Injuries & Damages
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Insurance	$ 835	$ 871	4%	$ 895	$ 990	11%	$ 1,017	3%	$ 1,030	1%	$ 1,037	1%
Reserve Appropriation (RFID)	226	226	0%	226	226	0%	226	0%	226	0%	226	0%
Total	$ 1,061	$ 1,097	3%	$ 1,121	$ 1,216	8%	$ 1,243	2%	$ 1,256	1%	$ 1,263	1%

Note:

1. The RFID amount for 2012-2016 years reflect annual appropriation of $0.190 million plus amortization of the balance over five year period [$0.036 million/year] to total $0.226 million per YUB Order 2013-01.

Table 3.12
Property Taxes
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Property Taxes	$ 312	$ 322	3%	$ 326	$ 331	1%	$ 331	0%	$ 473	43%	$ 686	45%

Table 3.13
Mid-Year Net Rate Base
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Year-End:												
Net plant in service[1]	$ 219,444	$ 216,964	-1%	$ 222,393	$ 217,202	-2%	$ 216,836	0%	$ 250,737	16%	$ 251,405	0%
Mid-Year:												
Net plant in service												
Before contributions	$ 377,608	$ 376,408	0%	$ 386,941	$ 382,576	-1%	$ 379,478	-1%	$ 402,204	6%	$ 425,340	6%
Less contributions	167,254	167,172	0%	166,023	165,732	0%	162,459	-2%	168,417	4%	174,269	3%
Net plant in service	210,354	209,236	-1%	220,918	216,844	-2%	217,019	0%	233,787	8%	251,071	7%
Mid-year regulatory deferral[2]	2,005	2,559	28%	1,486	1,693	14%	1,367	-19%	2,007	47%	2,061	3%
Working capital	4,108	4,021	-2%	4,280	4,521	6%	4,495	-1%	4,791	7%	4,928	3%
Net Rate Base	$ 216,467	$ 215,816	0%	$ 226,684	$ 223,058	-2%	$ 222,881	0%	$ 240,585	8%	$ 258,060	7%

Notes:
[1] Net plant in service at year end is gross property, plant and equipment plus deferred study and relicensing costs, less work in progress, depreciation, amortization, customer contributions, reserve for future removal and site restoration, deferred fire gain, and disallowed assets.
[2] This reflects the regulatory deferred costs (see Tab 5, Tables 5.3 to 5.8), excluding DSM and the balance of the hearing reserve account (see Table 3.14.1).

Table 3.14
Depreciation and Amortization
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fixed Asset Depreciation	$ 8,406	$ 8,503	1%	$ 8,989	$ 8,894	-1%	$ 8,906	0%	$ 9,828	10%	$ 10,615	8%
Less: Customer contribution	(3,536)	(3,584)	1%	(3,569)	(3,677)	3%	(3,691)	0%	(3,624)	-2%	(4,102)	13%
Less: Amortization of fire insurance recoveries	(262)	(270)	3%	(262)	(262)	0%	(262)	0%	(262)	0%	(262)	0%
Less: Disallowed Depreciation	(4)	(4)	0%	(16)	(16)	0%	(16)	0%	(16)	0%	(16)	0%
Plus: Amortization of deferred charges	3,324	3,580	8%	3,462	4,561	32%	2,846	-38%	2,764	-3%	1,581	-43%
Total Depreciation & Amortization	$ 7,927	$ 8,225	4%	$ 8,604	$ 9,500	10%	$ 7,783	-18%	$ 8,690	12%	$ 7,816	-10%

Notes:

1. Disallowed depreciation reflects fixed asset depreciation amounts for disallowed assets per YUB Orders: $0.004 million (YUB 1992-1) and $0.012 million (YUB 2013-01).

Table 3.15
Cost of Capital

	2012 GRA compliance	Actual 2012	Change	2013 GRA compliance	Actual 2013	Change	Actual 2014	Change	Actual 2015	Change	Actual 2016	Change
Average Cost of Debt	3.27%	3.47%	0.20%	3.58%	3.38%	-0.20%	3.22%	-0.16%	2.00%	-1.21%	2.10%	0.10%
Return on Equity	8.25%	3.30%	-4.95%	8.25%	7.42%	-0.83%	8.44%	1.01%	8.10%	-0.34%	8.69%	0.59%
Average Cost of Capital	5.26%	4.78%	-0.48%	5.45%	4.99%	-0.46%	5.36%	0.36%	4.50%	-0.86%	4.74%	0.24%